171 FERC ¶ 61,134
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick, Bernard L. McNamee,
and James P. Danly.

Alaska Gasline Development Corporation — Docket No. CP17-178-000

ORDER GRANTING AUTHORIZATION UNDER SECTION 3
OF THE NATURAL GAS ACT

(Issued May 21, 2020)

1. On April 17, 2017, Alaska Gasline Development Corporation (AGDC) filed an application under section 3 of the Natural Gas Act (NGA)[1] and Part 153 of the Commission's regulations[2] for authorization to site, construct, and operate facilities in the State of Alaska for the liquefaction and export of natural gas produced in the North Slope of the State of Alaska (Alaska LNG Project). For the reasons discussed in this order, we will authorize AGDC's proposed project, subject to the conditions discussed and attached herein.

I. Background and Proposal

2. AGDC is an independent, public corporation of the State of Alaska structured within the Department of Commerce, Community, and Economic Development. The Alaska State Legislature provided AGDC with the authority and primary responsibility for developing a liquefied natural gas (LNG) project on the State's behalf.[3]

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[1] 15 U.S.C. § 717b (2018).

[2] 18 C.F.R. pt. 153 (2019).

[3] ALASKA STAT. § 31.25.005.

3. The Alaska LNG Project consists of: a gas treatment plant located in the Prudhoe Bay Unit of Alaska's North Slope, and two natural gas pipelines connecting production units to the gas treatment plant; an approximately 806.9-mile-long, 42-inch-diameter pipeline (Mainline Pipeline) capable of transporting up to 3.9 billion cubic feet of gas per day (Bcf/day) from the gas treatment plant to the liquefaction facilities; 344,000 horsepower (hp) of compression located at eight compressor stations along the Mainline Pipeline; and liquefaction facilities on the Kenai Peninsula designed to produce up to 20 million metric tons per annum (MMTPA) of LNG (Liquefaction Facilities) for export.[4] AGDC estimates that the cost of the facilities will be between $40 and $45 billion.

4. Specifically, AGDC proposes to construct the following facilities:

- a gas treatment plant in Prudhoe Bay on the North Slope consisting of three parallel treatment trains for the removal of carbon dioxide and hydrogen sulfide from the feed gas, each sized to process up to 1.3 Bcf/day of gas (Prudhoe Bay Treatment Plant);

- 1.0 miles of 60-inch-diameter pipeline on the North Slope, which will extend from the Prudhoe Bay Unit gas production facility to the Prudhoe Bay Treatment Plant (Prudhoe Bay Unit Gas Transmission Line);

- 62.5 miles of 32-inch-diameter pipeline on the North Slope, which will extend from the Point Thomson Unit gas production facility to the Prudhoe Bay Treatment Plant (Point Thomson Unit Gas Transmission Line);

- 806.9 miles of 42-inch-diameter pipeline, which will extend from the Prudhoe Bay Treatment Plant and terminate at the Liquefaction Facilities on the Kenai Peninsula (Mainline Pipeline);[5]

- a compressor station with three gas-fired turbine compressor units, totaling 68,000 hp, located at Mainline Milepost (MP) 76.0 in the North Slope Borough (Sagwon Compressor Station);

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[4] The supply of natural gas for the Alaska LNG Project is located at the Prudhoe Bay and Point Thomson production units on the North Slope.

[5] The Mainline Pipeline will cross the North Slope, Fairbanks North Star, Denali, Matanuska-Susitna, and Kenai Peninsula Boroughs and the Yukon-Koyukuk Census Area. AGDC states that along the mainline there will be at least five gas interconnection points to allow for future in-state deliveries of natural gas.

- a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 148.5 in the North Slope Borough (Galbraith Lake Compressor Station);

- a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 240.1 in the Yukon-Koyukuk Census Area (Coldfoot Compressor Station);

- a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 332.6 in the Yukon-Koyukuk Census Area (Ray River Compressor Station);

- a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 421.6 in the Yukon-Koyukuk Census Area (Minto Compressor Station);

- a compressor station with one 42,000 hp gas-fired turbine compressor unit, located at Mainline MP 517.6 in the Denali Borough (Healy Compressor Station);

- a compressor station with one 33,000 hp gas-fired turbine compressor unit, located at Mainline MP 597.4 in the Matanuska-Susitna Borough (Honolulu Creek Compressor Station);

- a compressor station with one 33,000 hp gas-fired turbine compressor unit, located at Mainline MP 675.2 in the Matanuska-Susitna Borough (Rabideux Creek Compressor Station);

- a stand-alone gas heater station, located at Mainline MP 749.1 in the Matanuska-Susitna Borough (Theodore River Heater Station);

- liquefaction facilities capable of producing up to 20 MMTPA for export, located on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula, consisting of feed gas mercury and water removal facilities, fractionation facilities, three liquefaction trains, two 240,000 cubic meter tanks, and marine facilities capable of accommodating two LNG carriers simultaneously (Liquefaction Facilities); and

- various appurtenances.

5. On November 21, 2014, the Department of Energy's Office of Fossil Energy (DOE/FE) authorized Alaska LNG Project, LLC[6] to export, on a long-term, multi-contract basis, 20 MMTPA, or 2.55 Bcf/day, of LNG to nations with which the United States has a Free Trade Agreement (FTA).[7] On May 28, 2015, DOE/FE granted conditional authorization for the exportation of 20 MMTPA[8] of natural gas to nations that do not have an FTA.[9] AGDC states that it is in negotiations with producer members of Alaska LNG Project, LLC to obtain an option to purchase the LLC, which, as noted above, holds the DOE/FE export license and also owns the land for the Liquefaction Facilities site. AGDC states that it will make the required filings at DOE/FE to authorize a change in control over ownership of the export license to AGDC.

II. Procedural Issues

A. Notice, Interventions, Protests, and Comments

6. Notice of AGDC's application was published in the *Federal Register* on May 5, 2017, with motions to intervene due by May 22, 2017.[10] Timely, unopposed motions to intervene were filed by: Alyeska Pipeline Service Company; BP Exploration (Alaska) Inc. and BP Alaska LNG LLC, jointly; Center for Biological Diversity; Chickaloon Native Village Traditional Council; City of Valdez, Alaska; Conoco Phillips Company, ConocoPhillips Alaska LNG Company, and ConocoPhillips Alaska Natural Gas Corporation, jointly; ExxonMobil Alaska LNG LLC; ExxonMobil Alaska Production

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[6] The Alaska LNG Project, LLC's September 2014 Letter requesting prefiling for the Alaska LNG Project identified five partners: ExxonMobil Alaska LNG LLC, ConocoPhillips Alaska LNG Company, BP Alaska LNG LLC, TransCanada Alaska Midstream LP, and the Alaska Gasline Development Corporation.

[7] *See Alaska LNG Project, LLC*, FE Docket No. 14-96-LNG, Order No. 3554 (Nov. 21, 2014) (authorizing exports for a 30-year term, beginning on the earlier of the date of first exportation or 12 years from the date of DOE/FE's authorization) (DOE/FE Order No. 3554).

[8] This quantity is not additive to the volume approved to be exported to free trade nations set forth in DOE/FE Order No. 3554.

[9] *See Alaska LNG Project, LLC*, FE Docket No. 14-96-LNG, Order No. 3643 (May 28, 2015) (authorizing exports for a 30-year term, beginning on the earlier of the date of first exportation or 12 years from the date of DOE/FE's authorization) (DOE/FE Order No. 3643).

[10] 82 Fed. Reg. 21,223.

Inc.; Northern Alaska Environmental Center; Sierra Club; and National Parks Conservation Association.[11] On January 9, 2018, the Matanuska-Susitna Borough filed a motion to intervene out of time and comments. This late intervention was granted on February 27, 2018. On August 10, 2018, the Kenai Peninsula Borough filed a motion to intervene out of time, which was granted on September 11, 2018.

7. Sierra Club and the Center for Biological Diversity protested AGDC's application, arguing that the environmental impacts of the proposed project outweigh any benefits, and therefore, the project is not consistent with the public interest. Additionally, we received a number of comments in support of the project. On June 6, 2017, AGDC filed an answer to the comments by the Center for Biological Diversity and Sierra Club. Although the Commission's Rules of Practice and Procedure do not permit answers to protests,[12] we will accept the answers herein because they clarify the concerns raised and provide information that has assisted in our decision making. These concerns are addressed in the final Environmental Impact Statement (EIS) for the Alaska LNG Project and below.

B. Request for Evidentiary Hearing

8. In its motion to intervene, the Center for Biological Diversity requested a formal hearing on AGDC's application, "including the environmental impacts of and public need for the project."[13] Although our regulations provide for a hearing, neither the NGA nor our regulations require that such hearings be formal (i.e., trial-type) hearings. When the written record provides a sufficient basis for resolving the relevant issues, it is the Commission's practice to provide for a "paper hearing."[14] That is the case here. The

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[11] Timely, unopposed motions to intervene are automatically granted pursuant to Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214 (2019). In addition, on September 30, 2019, National Parks Conservation Association's Motion to Intervene and Protest was timely filed pursuant to the Commission's regulation at section 380.10(a), which states that "[a]ny person who files a motion to intervene on the basis of a draft environmental impact statement will be deemed to have filed a timely motion, in accordance with § 385.214, as long as the motion is filed within the comment period for the draft environmental impact statement." 18 C.F.R. § 380.10(a) (2019).

[12] 18 C.F.R. § 385.213(a)(2).

[13] May 22, 2017 Center for Biological Diversity Motion to Intervene at 7.

[14] *See Dominion Cove Point LNG, LP,* 148 FERC ¶ 61,244, at P 283 (2014), *reh'g denied,* 151 FERC ¶ 61,095 (2015). Moreover, the courts have repeatedly recognized that even where there are disputed issues "[the Commission] need not conduct such a [evidentiary] hearing if they may be adequately resolved on the written record."

issues raised in this proceeding have been adequately argued, and a determination can be made on the basis of the existing record in this proceeding. All interested parties have been afforded a full opportunity to present their views to the Commission through written submissions. We find that there is no material issue of fact that we cannot resolve on the basis of the written record in the proceeding. Therefore, we will deny the request for a formal, trial-type hearing.

III. Discussion

A. Jurisdiction Over the Alaska LNG Project

9. We acknowledge at the outset that the physical footprint of the Alaska LNG Project diverges significantly from any LNG facility for which the Commission has previously considered an application. As described above, the Alaska LNG Project includes a gas treatment plant located in the Prudhoe Bay Unit of Alaska's North Slope, two natural gas pipelines connecting production units to the gas treatment plant, liquefaction facilities on the Kenai Peninsula, and an approximately 806.9-mile-long, 42-inch-diameter pipeline connecting the gas treatment plant to the liquefaction facilities. While the Commission has previously authorized remotely located gas treatment facilities and shorter pipeline segments as part of an LNG terminal,[15] we have never exerted NGA section 3 jurisdiction over a project of this size. However, the scope of these facilities is a function of the unique nature of Alaska. Most pipelines delivering domestic gas to LNG export terminals have been subject to the Commission's NGA section 7 jurisdiction over interstate pipelines; but there are no existing interstate pipelines in Alaska and the pipeline proposed here will carry no gas in interstate commerce. In addition, there is no existing intrastate transmission system linking the North Slope production area to Alaska's market areas, which are relatively small and located a significant distance from the North Slope; nor is there a robust intrastate transmission system linking other instate production to multiple markets.

10. Section 3(e)(1) of the NGA states that "[t]he Commission shall have the exclusive authority to approve or deny an application for the siting, construction, expansion, or

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Moreau v. FERC, 982 F.2d 556, 568 (D.C. Cir. 1993). *See also Envtl Action v. FERC,* 996 F.2d 401, 413 (D.C. Cir. 1993); *Ala. Power Co. v. FERC,* 993 F.2d 1557, 1565 (D.C. Cir. 1993).

[15] *See Freeport LNG Development, L.P.*, 107 FERC ¶ 61,278 (2004), *order granting reh'g and clarification*, 108 FERC ¶ 61,253 (2004) (authorizing a 9.6-mile-long pipeline under section 3 of the NGA).

operation of an LNG terminal."[16] NGA section 2(11) defines LNG terminal as "all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, *transport*, gasify, liquefy, or process natural gas that is … exported to a foreign country from the United States … but does not include … any pipeline or storage facility subject to the jurisdiction of the Commission under [section 7]."[17]

11. In addition to the traditional (liquefaction and terminaling) LNG terminal facilities to be located on the Kenai Peninsula, AGDC's proposed Alaska LNG Project includes gas treatment facilities on the North Slope and the pipeline facilities necessary to transport gas from the North Slope to the liquefaction facilities. The definition of LNG terminal in NGA 2(11) is broad enough to encompass these facilities. Accordingly, consistent with section 2(11) of the NGA, we consider them part of AGDC's proposed LNG terminal.[18]

B. Public Interest Standard Under Section 3 of the NGA

12. Because the proposed facilities will be used to export natural gas to foreign countries, the construction and operation of the proposed facilities and site of their location require approval by the Commission under section 3 of the NGA.[19] While

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[16] 15 U.S.C. § 717b(e)(1) (2018).

[17] *Id.* § 717a(11).

[18] Prior to the passing of the Energy Policy Act of 2005, which introduced the definition of LNG terminal, the Commission declined to exercise any discretionary authority it may have had under section 3 of the NGA to regulate the siting, construction, and operation of a natural gas pipeline which would have transported gas from the North Slope of Alaska to the tidewater coast of Alaska at Valdez, for the purpose of exporting Alaskan North Slope gas to Asian markets. *See Yukon Pac. Corp.*, 39 FERC ¶ 61,216 (1987), *reh'g denied*, 40 FERC ¶ 61,164 (1987).

[19] The regulatory functions of NGA section 3 were transferred to the Secretary of Energy of the U.S. Department of Energy (DOE) in 1977 pursuant to section 301(b) of the Department of Energy Organization Act, (Pub. L. No. 95-91, 42 U.S.C. §§7101 *et seq*.§). The Secretary of Energy subsequently delegated to the Commission the authority to approve or disapprove the construction and operation of natural gas import and export facilities and the site at which such facilities shall be located. The most recent delegation is in DOE Delegation Order No, 00-004.00A, effective May 16, 2006. The Commission does not authorize importation or exportation of the commodity itself. Rather, applications for authorization to import or export natural gas must be submitted to the DOE. *See EarthReports, Inc. v. FERC*, 828 F.3d 949, 952-53 (D.C. Cir. 2016)

section 3 provides that an application for the exportation or importation of natural gas shall be approved unless the proposal "will not be consistent with the public interest," section 3 also provides that an application may be approved "in whole or in part, with such modification and upon such terms and conditions as the Commission may find necessary or appropriate."[20] NGA section 3(a) further provides that, for good cause shown, the Commission may make such supplemental orders as it may find "necessary or appropriate."[21]

13. Commenters state that the Commission must consider the numerous adverse environmental impacts of the proposed project when determining whether the siting, construction, and operation of the facilities are consistent with the public interest.[22] With respect to non-environmental issues, Sierra Club contends that the Commission must go beyond a simple cost-benefit analysis and consider whether most people will be made worse off by the project, even if a few people will experience benefits.[23] Sierra Club further asserts that the Commission cannot simply rely on the DOE's assessment of the public interest, because DOE "merely considers exports of natural gas in the abstract . . . [and] is not focused on the impacts of the actual infrastructure."[24] Center for Biological Diversity asserts that the AGDC has failed to provide support for the contention that the project as proposed "are a 'necessity' for Alaska" and points to facts that oil companies have pulled out of the project and "the surplus of LNG on the world market" as indicia

(detailing how regulatory oversight for the export of LNG and supporting facilities is divided between the Commission and DOE).

[20] 15 U.S.C. §§ 717b(a) and 717b(e)(3) (2018). For a discussion of the Commission's authority to condition its approvals of LNG facilities under section 3 of the NGA, *see, e.g., Distrigas Corp. v. FPC*, 495 F.2d 1057, 1063-64 (D.C. Cir. 1974), *cert. denied*, 419 U.S. 834 (1974), and *Dynegy LNG Production Terminal, L.P.*, 97 FERC ¶ 61,231 (2001).

[21] 15 U.S.C. § 717b(a).

[22] Sierra Club May 22, 2017 Motion to Intervene at 3; Center for Biological Diversity May 22, 2017 Motion to Intervene at 5-6 (noting the project will also lead to increased natural gas production and exacerbate climate change effects).

[23] Sierra Club May 22, 2017 Motion to Intervene at 4-5.

[24] *Id*. at 5.

that the project is not consistent with the public interest.[25] Center for Biological Diversity also contends the project could negatively impact taxpayers in Alaska[26]

14. Section 3(a) of the NGA provides, in part, that "no person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so."[27] As noted above, in 1977 the Department of Energy Organization Act transferred the regulatory functions of section 3 of the NGA to the Secretary of Energy. Subsequently, the Secretary of Energy delegated to the Commission authority to "[a]pprove or disapprove the construction and operation of particular facilities, the site at which such facilities shall be located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports."[28]

15. However, the Secretary, has not delegated to the Commission any authority to approve or disapprove the import or export of the commodity itself.[29] Nor is there any indication that the Secretary's delegation authorized the Commission to consider the economic issues raised in these proceedings as part of the Commission's public interest determination, thus duplicating and possibly contradicting the Secretary's own decisions. Therefore, we decline to address commenters' economic claims (e.g., the state of world demand for LNG), which are relevant only to the exportation of the commodity of natural gas, which is within DOE's exclusive jurisdiction, and are not implicated by our limited action of reviewing proposed terminal sites. The Commission's authority under NGA section 3 applies "only to the siting and the operation of the facilities necessary to

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[25] Center for Biological Diversity May 22, 2017 Motion to Intervene at 6.

[26] *Id*.

[27] 15 U.S.C. § 717b(a).

[28] DOE Delegation Order No. 00-004.00A.

[29] *See supra* note 19; *see also Freeport LNG Development, L.P.*, 148 FERC ¶ 61,076, *reh'g denied*, 149 FERC ¶ 61,119 (2014), *aff'd sub nom. Sierra Club v. FERC*, 827 F.3d 36 (D.C. Cir. 2016) (*Freeport*) (finding that because the Department of Energy, not the Commission, has sole authority to license the export of any natural gas through LNG facilities, the Commission is not required to address the indirect effects of the anticipated export of natural gas in its National Environmental Policy Act (NEPA) analysis); *Sabine Pass Liquefaction, LLC*, 146 FERC ¶ 61,117, *reh'g denied*, 148 FERC ¶ 61,200 (2014), *aff'd sub nom. Sierra Club v. FERC*, 827 F.3d 59 (D.C. Cir. 2016) (*Sabine Pass*).

accomplish an export[,]"[30] while "export decisions [are] squarely and exclusively within the [DOE]'s wheelhouse . . . .[31] Similarly, issues related to the impacts of natural gas development and production and the ultimate use of the product[32] are related to DOE's authorization of the export and not the Commission's siting of the facilities.[33]

16. As the U.S. Court of Appeals for the D.C. Circuit has explained, the NGA section 3 standard that a proposal "shall" be authorized unless it "will not be consistent with the public interest[,]"[34] "sets out a general presumption favoring such authorization[s]."[35] To overcome this favorable presumption and support denial of an NGA section 3 application, there must be an "affirmative showing of inconsistency with the public interest."[36] We have reviewed AGDC's application to determine if the siting, construction, and operation of its facilities as proposed would not be consistent with the public interest.[37] As noted above, the Alaska State Legislature provided AGDC with the authority and primary responsibility for developing an LNG project on the State's behalf. The proposed project will be located on commercial, private, federal, and state-owned

[30] *Trunkline Gas Co., LLC,* 155 FERC ¶ 61,328, at P 18 (2016).

[31] *Sierra Club v. FERC,* 827 F.3d at 46.

[32] Center for Biological Diversity May 22, 2017 Motion to Intervene at 6.

[33] *Sierra Club v. FERC*, 827 F.3d at 46.

[34] 15 U.S.C. § 717b(a). In addition, NGA section 3(c) provides that the exportation of gas to FTA nations "shall be deemed to be consistent with the public interest." 15 U.S.C. § 717b(c). As noted above, AGDC has received authorization to export to FTA nations. *See supra* P 5.

[35] *EarthReports v. FERC*, 828 F.3d at 953 (quoting *W. Va. Pub. Servs. Comm'n v. U.S. Dep't of Energy*, 681 F.2d 847, 856 (D.C. Cir. 1982)); *see also Sierra Club v. U.S. Dep't of Energy*, 867 F.3d 189, 203 (D.C. Cir. 2017).

[36] *Sierra Club v. U.S. Dep't of Energy*, 867 F.3d at 203 (quoting *Panhandle Producers & Royalty Owners Ass'n v. Econ. Regulatory Admin.*, 822 F.2d 1105, 1111. (D.C. Cir. 1987)).

[37] *See National Steel Corp.*, 45 FERC ¶ 61,100, at 61,332-33 (1988) (observing that DOE, "pursuant to its exclusive jurisdiction, has approved the importation with respect to every aspect of it except the point of importation" and that the "Commission's authority in this matter is limited to consideration of the place of importation, which necessarily includes the technical and environmental aspects of any related facilities.").

land. The gas treatment plant would be on state land designated for oil and natural gas development within the North Slope Borough. Although the Mainline Pipeline corridor will be within 100 feet of existing cleared corridors for only about 20 percent of its length, it is generally sited along existing corridors for most of its length.[38] Specifically, commencing at the gas treatment facility, the Mainline Pipeline would generally follow the existing Trans Alaska Pipeline System (TAPS) crude oil pipeline and adjacent highways south to Livengood, Alaska. From Livengood, the Mainline Pipeline would head south-southwest to Trapper Creek following the George Parks and Beluga Highways. The Liquefaction Facilities will be sited in an industrial area on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula.

17. Consistent with the urgings of the Sierra Club and the Center for Biological Diversity, among others, Commission staff has prepared a comprehensive EIS thoroughly analyzing all environmental impacts properly associated with our action of approving the siting and operation of the Alaska LNG Project. As discussed below, the final EIS finds that, while some impacts would be permanent and significant, such as impacts on permafrost, most impacts would not be significant or would be reduced to less-than-significant levels with the implementation of avoidance, minimization, and mitigation measures recommended in the final EIS[39] and adopted by this order. In addition, as a potential offset to the unsupported allegation of harm to Alaskan taxpayers posited by the Center for Biological Diversity, we note that the project would have economic and local/regional public benefits, including increased employment opportunities and household income from both project construction and operation, and beneficial impacts from project operation such as increased employment and household income.[40] We find that the various arguments raised regarding the Alaska LNG Project do not amount to an affirmative showing of inconsistency with the public interest that is necessary to overcome the presumption in section 3 of the NGA.

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[38] Final EIS at 4-265.

[39] As part of its environmental review, staff developed mitigation measures it determined would appropriately and reasonably reduce the environmental impacts resulting from project construction and operation. AGDC has committed to implementing 40 of the recommended mitigation measures set forth in the draft EIS. *See Id.* at Appendix X. As AGDC has committed to implementing these mitigation measures, they were removed as recommendations from the final EIS; however, in accordance with Environmental Condition 1 below, AGDC would be required to follow all mitigation it has committed to implementing during construction and operation.

[40] *Id*. at 4-1026.

18. In accordance with the Memorandum of Understanding signed on August 31, 2018, by the Commission and the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA),[41] PHMSA undertook a review of the proposed Liquefaction Facilities' ability to comply with the federal safety standards under Part 193, Subpart B, of Title 49 of the Code of Federal Regulations.[42] On February 4, 2020, PHMSA issued a Letter of Determination (LOD) indicating that AGDC has demonstrated that the siting of the Alaska LNG Project complies with these federal safety standards. If the project is subsequently modified so that it differs from the details provided in the documentation submitted to PHMSA, further review would be conducted by PHMSA.

19. AGDC is proposing to operate its LNG terminal under the terms and conditions mutually agreed to by its customers and will solely bear the responsibility for the recovery of any costs associated with construction and operation of the terminal and associated facilities. Accordingly, AGDC's proposal does not trigger NGA section 3(e)(4).[43]

20. In view of the above, after careful consideration of the entire record of this proceeding, including the findings and recommendations of the final EIS, we find that, subject to the conditions imposed in this order, AGDC's proposal is not inconsistent with the public interest. Therefore, we will grant AGDC's application.

C. Environmental Analysis

21. To satisfy the requirements of the National Environmental Policy Act of 1969 (NEPA),[44] Commission staff prepared an EIS to evaluate the potential environmental impacts of the proposed project. A number of agencies participated as cooperating agencies in the preparation of the EIS: the Bureau of Land Management (BLM); the National Oceanic Atmospheric Administration's National Marine Fisheries Service (NMFS); the National Park Service (NPS); the U.S. Army Corp of Engineers (COE); the U.S. Coast Guard (Coast Guard); DOE; PHMSA; the U.S. Environmental Protection

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[41] *Memorandum of Understanding Between the Department of Transportation and the Federal Energy Regulatory Commission Regarding Liquefied Natural Gas Facilities* (Aug. 31, 2018), https//www.ferc.gov/legal/mou/2018/FERC-PHMSA-MOU.pdf.

[42] 49 C.F.R. pt. 193, subpt. B (2019).

[43] 15 U.S.C. § 717b(e)(4) (governing orders for LNG terminal offering open access service).

[44] 42 U.S.C. § 4321 *et seq*. (2018). *See also* the Commission's NEPA regulations at 18 C.F.R. pt. 380 (2019).

Agency (EPA); and the U.S. Fish and Wildlife Service (FWS). Cooperating agencies have jurisdiction by law or special expertise with respect to resources potentially affected by the proposed action participate in the preparation of the NEPA analysis.

22. Commission staff began the environmental review of the project during the Commission's pre-filing process in September 2014 (Docket No. PF14-21-000). The pre-filing process encourages the early involvement of interested stakeholders and regulatory agencies to identify and resolve environmental issues before an application is filed with the Commission. Commission staff participated in a number of public meetings as part of the pre-filing process, including 14 open house meetings hosted by AGDC in the project area from October 2014 through January 2015. Subsequently, staff held a nine-month public scoping period, ending on December 4, 2015. Staff held 12 public scoping meetings in the communities in the project area. As discussed in more detail below, staff held a supplemental scoping period to solicit comments regarding the Denali National Park and Preserve Alternative. During this supplemental period staff held a public forum and solicited written comments.

23. On June 28, 2019, the Commission issued a Notice of Availability of the draft EIS, establishing an October 3, 2019 deadline for filing comments. Notice of the availability of the draft EIS was published in the *Federal Register* on July 8, 2019.[45] The draft EIS addressed the issues raised during the scoping period, as well as the 248 written scoping comment letters received from federal and state agencies, elected officials, Alaska Native tribes, non-governmental organizations, affected landowners, individuals, groups, and companies. A separate notice issued on July 26, 2019, provided the dates and locations of eight public comment meetings to allow interested parties to present oral comments on the draft EIS. The transcripts of the public comment sessions and all written comments on the draft EIS are part of the public record for the project.[46]

24. On March 6, 2020, the Commission issued the final EIS for the project and on March 12, 2020, a public Notice of Availability of the final EIS was published in the *Federal Register*.[47] The final EIS addresses: geological resources and hazards; soils and sediments; water resources; wetlands; vegetation; wildlife resources; aquatic resources; threatened, endangered, and other special status species; land use, recreation, and special

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[45] 84 Fed. Reg. 32,451 (July 8, 2019).

[46] Transcripts of each scoping meeting, summaries of the meetings and conference calls, and all written comments are available for viewing on the FERC website (http://www.ferc.gov). *See also Appendix CC* to the March 3, 2020 final EIS, *Responses to Comments on the Draft EIS.*

[47] 85 Fed. Reg. 14,470 (March 12, 2020).

interest areas; visual resources; socioeconomics; transportation; cultural resources; subsistence; air quality; noise; public health and safety; reliability and safety; cumulative impacts; and alternatives to the proposed action. We received 116 letters commenting on the draft EIS; and 35 individuals made oral comments during the public comment meetings. The final EIS addresses all substantive comments received on the draft EIS.[48]

25. The final EIS concludes that project construction and operation would have significant impacts on permafrost, wetlands, forests, and caribou, specifically the Central Arctic Herd, as well as some sensitive noise receptors. Emissions from the Prudhoe Bay Treatment Plant and Liquefaction Facilities could have a significant impact on regional haze and acid deposition in some Class I and Class II nationally designated areas, although mitigation measures could be implemented by the State of Alaska during the air permitting phase that would reduce these impacts.

a. Issues Relating to the NEPA Process

26. We received several comments concerning the NEPA process. Some commenters requested an extension of time to file comments on the draft EIS.[49] The Commission's standard comment period on a draft EIS is 45 days, which is consistent with CEQ's regulations.[50] Here, the Commission provided a 90-day comment period. We find that this was sufficient time to review and comment on the draft EIS. Moreover, in preparing the final EIS, Commission staff considered late-filed comments on the draft EIS to the extent practicable.

27. Several commenters argued the draft EIS was deficient because of what they deemed missing information,[51] or other "serious deficiencies."[52] Commenters assert a corrected or supplemental draft EIS should have been issued for comment to address these issues. We disagree. The draft EIS is a draft of the agency's proposed final EIS

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[48] Additional comments on the draft EIS were filed after the close of the comment period, which were addressed in the final EIS to the extent practicable.

[49] *See e.g.*, Trustee for Alaska's October 3, 2019 Comments at 1.

[50] *See* 40 C.F.R. § 1506.10(c) (2019).

[51] Earthjustice, Chickaloon Village Traditional Council, Sierra Club, Northern Alaska Environmental Center, Defenders of Wildlife, Cook Inletkeeper, and The Wilderness Society (jointly, Earthjustice) October 3, 2019 Comments at 32-33; Center for Biological Diversity October 3, 2019 Comments at 8-9.

[52] Trustees for Alaska October 3, 2019 Comments at 17.

and, as such, its purpose is to elicit suggestions for change. A draft is adequate when, as here, it allows for "meaningful analysis" and "make[s] every effort to disclose and discuss" major points of view on the environmental impacts.[53]

28. There was no need to issue a supplemental draft EIS. The CEQ regulations require agencies to prepare supplements to a draft or final EIS if: (i) the agency makes substantial changes to the proposed action that are relevant to environmental concerns; or (ii) there are significant new circumstances or information relevant to environmental concerns and bearing on the proposed action or its impact.[54] Here, the final EIS, which incorporates comments filed on the draft EIS, contains ample information for the Commission to fully consider and address the environmental impacts associated with the Alaska LNG Project. The additional material in the final EIS relates to issues discussed in the draft EIS and did not result in any significant modification of the project that would require additional public notice or issuance of a revised draft EIS for further comment.

29. We also reject commenters' claim that allowing AGDC to submit new information and create mitigation plans after the public comment period closes "circumvents the purposes of NEPA and applicable NEPA regulations."[55] NEPA does not require a complete mitigation plan be actually formulated at the onset, but only that the proper procedures be followed for ensuring that the environmental consequences have been fairly evaluated.[56] In addition, NEPA does not require every study or aspect of an analysis to be completed before an agency can issue a final EIS, and the courts have held that agencies do not need perfect information before it takes any action.[57] The final EIS

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[53] 40 C.F.R. § 1502.9(a) (2019); *see also Nat'l Comm. for the New River, Inc. v. FERC*, 373 F.3d 1323, 1328 (D.C. Cir. 2004) (*Nat'l Comm. for the New River*) (holding that FERC's draft EIS was adequate even though it did not have a site-specific crossing plan for a major waterway where the proposed crossing method was identified and thus provided "a springboard for public comment") (quoting *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989) (*Methow Valley Citizens Council*)).

[54] 40 C.F.R. § 1502.9(c) (2019).

[55] Trustee for Alaska's October 3, 2019 Comments at 1.

[56] *See Methow Valley Citizens Council*, 490 U.S. at 352-53.

[57] *U.S. Dep't of the Interior v. FERC*, 952 F.2d 538, 546 (D.C. Cir. 1992); *State of Alaska v. Andrus*, 580 F.2d 465, 473 (D.C. Cir. 1978), *vacated in part sub nom. W. Oil & Gas Ass'n v. Alaska*, 439 U.S. 922 (1978) ("NEPA cannot be 'read as a requirement that [c]omplete information concerning the environmental impact of a project must be

identified baseline conditions for all relevant resources. Final mitigation plans will not present new environmentally significant information nor pose substantial changes to the proposed action that would otherwise require a supplemental EIS. As we have explained in other cases, practicalities require the issuance of orders before completion of certain reports and studies because large projects, such as this, take considerable time and effort to develop.[58] Accordingly, post-authorization studies may properly be used to develop site-specific mitigation measures.

30. As discussed further below, the final EIS recommends, and we require in this order, that AGDC not commence construction of the project until it provides certain outstanding information[59] and confirms it has received all applicable authorizations required under federal law.[60]

31. Based on the above, we find that the Commission has provided the public a meaningful opportunity to participate in the NEPA process (as well as our larger application review process) and that doing so has resulted in a sufficient record to fully inform the Commission decision. Accordingly, we deny the requests to "correct" claimed deficiencies in the draft EIS and extend the comment period.

32. Several commenters contend that the draft EIS inappropriately defined the purpose and need[61] of the project too narrowly by relying on AGDC's proposal which, they

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obtained before action may be taken."') (quoting *Jicarilla Apache Tribe of Indians v. Morton*, 471 F.2d 1275, 1280 (9th Cir. 1973)).

[58] *See, e.g.*, *Algonquin Gas Transmission, LLC*, 154 FERC ¶ 61,048, at P 94 (2016)*; East Tennessee Natural Gas Co.*, 102 FERC ¶ 61,225, at P 23 (2003), *aff'd sub nom. Nat'l Comm. for the New River*, 373 F.3d 1323.

[59] For example, Environmental Condition 22 requires AGDC to, prior to construction, file for the review and written approval of the Director of the Office of Energy Projects, or the Director's designee, an updated Unanticipated Contamination Discovery Plan that indicates measures that will be taken if contaminated sediments are discovered in marine water environments, and to update the plan to notify NPS if there is an unanticipated discovery of contamination on NPS property.

[60] Environmental Condition 12.

[61] The draft EIS's stated purpose and need is "to commercialize the natural gas resources of Alaska's North Slope (North Slope), by converting the existing natural gas supply to liquefied natural gas (LNG) for export and providing gas for users within the State of Alaska." Draft EIS at ES-1.

assert, led to an insufficient analysis of alternatives to the project.[62] We disagree. An agency's environmental document must include a brief statement of the purpose and need to which the proposed action is responding.[63] An agency uses the purpose and need statement to define the objectives of a proposed action and identify and then provide legitimate consideration to reasonable alternatives.[64] CEQ has advised that "[r]easonable alternatives include those that are practical or feasible from the technical and economic standpoint and using common sense, rather than simply desirable from the standpoint of the applicant."[65] Courts have upheld federal agencies' use of applicants' project purpose and need as the basis for evaluating alternatives.[66] When an agency is asked to consider a specific plan, the needs and goals of the parties involved in the application should be taken into account.[67]

33. We recognize that a project's purpose and need should not be so narrowly defined as to preclude consideration of what may actually be reasonable alternatives.[68] Nonetheless, an agency need only consider alternatives that will bring about the ends of the proposed action, and the evaluation is "shaped by the application at issue and by the function that the agency plays in the decisional process."[69]

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[62] *See, e.g.*, Center for Biological Diversity October 3, 2019 Comments at 10-11.

[63] *See* 40 C.F.R. § 1508.9 (2019) (for an Environmental Assessment); 40 C.F.R. § 1502.13 (for an EIS).

[64] *See Colo. Envtl. Coal. v. Dombeck*, 185 F.3d 1162, 1175 (10th Cir. 1999).

[65] *Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations*, 46 Fed. Reg. 18,026-27 (Mar. 23, 1981).

[66] *E.g., City of Grapevine v. U.S. Dep't of Transp.*, 17 F.3d 1502, 1506 (D.C. Cir. 1994).

[67] *Citizens Against Burlington, Inc. v. Busey*, 938 F.2d 190, 196 (D.C. Cir. 1991).

[68] *Id.*.

[69] *Id.* at 199; *see also Sierra Club v. U.S. Forest Serv.*, 897 F.3d 582 (4th Cir. 2018) (finding the statement of purpose and need for a Commission jurisdictional natural gas pipeline project that explained where the gas must come from, where it will go, and how much the project would deliver, allowed for a sufficiently wide range of alternatives but was narrow enough that there were not an infinite number of alternatives).

34. For the Alaska LNG Project, the EIS appropriately relied on the applicant's stated purpose and need. We find that doing so did not preordain that the project as originally proposed was the only way to satisfy the specified purpose and need. Indeed, Commission staff identified numerous reasonable alternatives to the project components, which were rigorously evaluated in the EIS.[70] As discussed further below, staff found that the alternatives analyzed would either not meet the projects' purpose and need, would not be technically and economically feasible, or would not offer a significant environmental advantage when compared to the proposed action.

35. We also reject claims that the draft EIS's conclusions about the impacts of the "no action" alternative, and what commenters deem the dismissal of the alternative from further consideration, are arbitrary. Earthjustice asserts the draft EIS did not take a "hard look" at the no action alternative, as it challenges the draft EIS's finding that the no action alternative would not be environmentally advantageous because AGDC or others would likely develop a similar new project.[71] However, the draft EIS clearly states that the no action alternative means the proposed facilities would not be constructed and the associated environmental impacts would not occur, and as a result, the environment would not be affected.[72]

36. The EIS took the requisite hard look at the no action alternative: the resource-by-resource discussion in section 4 of the final EIS first details the existing state of each resource and then describes the environmental impacts of the preferred alternative. Section 5 of the final EIS summarizes staff's conclusions about those impacts. By providing a description of the existing state of each resource and a description of the environmental impacts of the preferred alternative, the final EIS provides the Commission with a meaningful comparison of the effects that would be avoided under a no action alternative.

37. Several commenters assert the Commission must analyze the upstream and downstream air emissions impacts associated with the Alaska LNG Project.[73] They argue that project impacts include the climate consequences of both the upstream greenhouse gases (GHG) emitted by the extraction and processing of the natural gas before it enters

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[70] *Id*. at 3-1 – 3-52.

[71] Earthjustice October 3, 2019 Comments at 5.

[72] Final EIS at ES-6.

[73] *See, e,g.*, Earthjustice October 3, 2019 Comments at 37-38. Institute for Policy Integrity, et.al., October 3, 2019 Comments at 4; Center for Biological Diversity, October 3, 2019 Comments at 17-20.

the pipeline system and downstream greenhouse gases emitted by the combustion of the natural gas in power plants, industrial facilities, heating and cooking appliances, and other end uses.[74] They assert that, contrary to the draft EIS's findings, the downstream GHG emissions of pipelines are an indirect, reasonably foreseeable effect of authorizing the project and must be analyzed and disclosed.[75]

38. Indirect effects are defined as those "which are caused by the action and are later in time or farther removed in distance but are still reasonably foreseeable."[76] Accordingly, to determine whether an impact should be studied as an indirect impact, the Commission must determine whether it is (1) caused by the proposed action; and (2) reasonably foreseeable.[77]

39. Courts have found that an impact is reasonably foreseeable if it is "sufficiently likely to occur that a person of ordinary prudence would take it into account in reaching a decision."[78] Although NEPA requires "reasonable forecasting,"[79] an agency "is not required to engage in speculative analysis[80] or "to do the impractical, if not enough information is available to permit meaningful consideration."[81]

40. Upstream and downstream activities related to the production and transportation of natural gas and ultimate consumption of the exported LNG are not indirect effects of the

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[74] *See, e.g.*, Center for Biological Diversity, October 3, 2019 Comments at 19-21; Earthjustice October 3, 2019 Comments at 38.

[75] Institute for Policy Integrity *et*. al October 3, 2019 Comments at 4-5.

[76] 40 C.F.R. § 1508.8(b) (2019).

[77] *Id.; see also id.* § 1508.25(c).

[78] *EarthReports, Inc. v. FERC*, 828 F.3d at 955 (citations omitted); *see also Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992).

[79] *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1079 (9th Cir. 2011) (quoting *Selkirk Conservation Alliance v. Forsgren*, 336 F.3d 944, 962 (9th Cir. 2003)).

[80] *Id.* at 1078.

[81] *Id.* (quoting *Envtl. Prot. Info. Ctr. v. U.S. Forest Serv.*, 451 F.3d 1005, 1014 (9th Cir. 2006) (internal quotation marks and citation omitted)).

siting, construction, and operation of the proposed LNG terminal.[82] As discussed above, the courts have explained that, because the authority to authorize the LNG exports rests with DOE, NEPA does not require the Commission to consider the upstream or downstream GHG emissions that may be indirect effects of the export itself when determining whether the related LNG export facility satisfies section 3 of the NGA.[83]

41. In this case, as discussed in more detail below, construction and operational emissions associated with the Alaska LNG Project are included in the emissions estimate Commission staff provided. However, the majority of the gas delivered to the LNG terminal will be liquefied for export. The end-use of the LNG is unknown, and, as stated above, the Commission does not have authority over, and need not address the effects of, the anticipated export of the gas.[84]

42. Some commenters assert that the Commission's NEPA analysis is flawed because it does not consider the significance of the project's effects on climate change. Specifically, they claim the draft EIS is deficient because it does not use the Social Cost of Carbon, or a similar tool (e.g., the Social Cost of Methane or the Social Cost of Nitrous Oxide), to evaluate climate change impacts.[85]

43. The Social Cost of Carbon has been described as an estimate of climate change damage associated with an incremental increase in carbon dioxide (CO_2) emissions in a given year.[86] The Commission has provided extensive discussion on why the Social Cost of Carbon is not appropriate in project-level NEPA review and cannot meaningfully inform the Commission's decisions on natural gas infrastructure projects under the

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[82] *See, e.g.*, *Jordan Cove Energy Project, L.P.*, 170 FERC ¶ 61,202, at P 171 (2020); *Annova LNG Common Infrastructure, LLC*, 169 FERC ¶ 61,132, at P 22 (2019).

[83] *See Freeport*, 827 F.3d 36, at 46-47 (2016); *see also Sierra Club v. FERC*, 867 F.3d 1357, 1373 (D.C. Cir. 2017) (*Sabal Trail*) (discussing *Freeport*).

[84] *Freeport*, 827 F.3d at 47.

[85] *See e.g.*, Earthjustice October 3, 2019 Comments at 34-36; Institute for Policy Integrity October 3, 2019; Sabin Center for Climate Change Law, October 3, 2010 Comments.

[86] Interagency Working Group on the Social Cost of Greenhouse Gases, *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866*, at 3 (Aug. 2016), https://www.epa.gov/sites/production/files/2016-2/documents/sc_co2_tsd_august_2016.pdf

NGA.[87] We adopt that reasoning here. Moreover, the Commission has explained it does not use monetized cost-benefit analyses as part of its NEPA review.[88] As discussed further below, and explained in the final EIS, there is no universally-accepted methodology for evaluating the project's impacts on climate change.[89]

b. Major Environmental Issues Addressed in the Final EIS

1. Geology

44. The Alaska LNG Project's route would traverse a range of geologic conditions and resources.[90] AGDC conducted studies to characterize geologic conditions and developed structural and mechanical design elements to address these conditions. AGDC also proposes measures to mitigate or minimize impacts on or near geologic resources during construction and operation, as well as impacts of geologic conditions on the project.

45. Mineral resources are present along the Mainline Pipeline, including about 60 state and four federal mining claims within the project footprint.[91] AGDC has stated that

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[87] *Mountain Valley*, 161 FERC ¶ 61,043, at P 296, *order on reh'g*, 163 FERC ¶ 61,197, at PP 275-297 (2018), *aff'd, Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199, at *2 (unpublished) ("[The Commission] gave several reasons why it believed petitioners' preferred metric, the Social Cost of Carbon tool, is not an appropriate measure of project-level climate change impacts and their significance under NEPA or the Natural Gas Act. That is all that is required for NEPA purposes.").

[88] *See Florida Southeast Connection, LLC*, 162 FERC ¶ 61,233, at PP 39-44 (2018).

[89] Final EIS at 4-1222. *See generally Transcontinental Gas Pipe Line Co., LLC*, 171 FERC ¶ 61,032 (2020) (McNamee, Comm'r, concurring at PP 63-74) (elaborating on how the Social Cost of Carbon is not a useful tool for determining whether GHG emissions are significant and that it is not appropriate for the Commission to establish its own criteria for determining the significance of GHG emissions out of whole cloth).

[90] *Id*. at 4-5 through 4-62.

[91] *Id*. at 4-11. Mineral resources within 0.5 mile of the project were identified by reviewing aerial photographs and publicly available information from the US Geological Survey (USGS), Alaska Department of Natural Resources, Alaska Resource Data File, Alaska State Geo-spatial Data Clearinghouse, and BLM Mineral Assessments. AGDC filed aerial map sets in response to staff information requests for Resource Report 6 (Accession Nos. 20171002-5306 and 20171201-5163). They can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search"

surface and/or subsurface mining would not be allowed within the footprint of the permanent project facilities and access roads; and access to resources in these areas would be permanently blocked to prevent damage to the project.[92] Blasting and drilling activities to access mineral resources proximal to the project would be restricted and evaluated for safety on a case-by-case basis by the appropriate land management agency.

46. Several commenters raised concerns regarding access to existing mining claims or leases near the project construction rights-of-way. As noted by the State of Alaska in its comments on the draft EIS, any limitations on mining must be consistent with state laws and regulations, as determined by the agencies that authorize such activity.[93] For example, AS 38.34.050(c) requires acquisition of a right-of-way permit for a gas pipeline transmission corridor, which is granted by the Alaska Department of Natural Resources (ADNR) Commissioner. However, state land may be closed to multiple purpose use (e.g., mining and pipeline corridor) where the ADNR Commissioner makes a finding that multiple purpose use would be incompatible with significant surface uses on the state land, or when classification is necessary for the development of utility or transportation corridors.[94] If the state declines permitting authorization for portions of the alignment authorized by the Commission, then AGDC would need to file a revised route for review and approval by the Commission and other federal agencies with jurisdiction.[95]

47. AGDC will use granular fill[96] to provide structural support for equipment to travel over permafrost terrain, thus providing a stable surface between equipment and the underlying permafrost. AGDC estimates that project construction would require 31.3 million cubic yards total of granular fill, which would be sourced from about 150 potential off-right-of-way sources with a combined area of about 6,000 acres.[97] Of the potential material sites, only sites that are available for project use and have not been

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from the eLibrary menu and enter 20171002-5306 and 20171201-5163 in the "Numbers: Accession Number" field.

[92] *Id*. at 4-418 – 4-410.

[93] *Id*.

[94] *Id*.

[95] *Id*. at 4-18 - 4-19.

[96] Granular fill refers to coarse-grained particles (consisting of a combination of gravels, sands, and fines) and characterize fill materials deemed suitable for construction.

[97] Final EIS at Appendix C, Table C-8.

assigned for highway or other projects would be developed, in accordance with AGDC's *Gravel Sourcing Plan and Reclamation Measures*.[98] Because specific material sites and volumes have not been finalized, prior to construction AGDC would file with the Commission for review and written approval an updated *Gravel Sourcing Plan and Reclamation Measures*, finalized in coordination with appropriate state and federal agencies, that identifies the material volumes to be acquired from each site.[99]

48. AGDC provided the results of a series of geohazard analyses conducted to determine areas where geologic hazards[100] would be encountered by the project and where potential impacts associated with these hazards would need to be mitigated. Geologic hazards with the potential to affect the project include seismicity, soil liquefaction, mass wasting,[101] tsunamis and seiches,[102] land subsidence, acid rock drainage (ARD), naturally occurring asbestos, volcanism, and hydrologic processes and flooding.

49. AGDC proposed mitigation measures in areas of known seismic hazards, such as avoidance of fault crossings and modification of pipeline geometry to minimize exposure to ground movement along faults.[103] The Mainline Pipeline would be installed aboveground where it crosses the Denali, Northern Foothills, Castle Mountain, and Park Road faults, using designs which will accommodate the maximum predicted horizontal and vertical displacement at the faults.[104] As described in more detail in the reliability and safety section of the EIS, the Liquefaction Facilities will be built in accordance with

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[98] *Id*. at 4-20.

[99] *Id*.

[100] Geologic hazards are natural, physical conditions that can damage lands and structures or injure people. *Id.* at 4.21.

[101] Mass wasting encompasses geologic hazards that involve down-slope movement of several types of materials, including rock, soil, sediment, snow, or ice, at timescales ranging from slow and creeping to fast and catastrophic. *Id*. at 4-29.

[102] Tsunamis are large waves generated by seafloor vertical fault displacement that propagate through water, while seiches are oscillating waves in partially or entirely enclosed waterbodies that can be generated by submarine landslides, submarine and subaerial mass movements, earthquakes, storms, and strong winds. *Id*. at 4-32.

[103] *Id*. at 4-43.

[104] *Id*.

federal standards based on the susceptibility of critical safety systems to ground shaking and the LNG plant's ability to continue functioning during an earthquake.[105] Although the Prudhoe Bay Treatment Plant will not be regulated under these federal standards, the Prudhoe Bay Treatment Plant facilities will be built to withstand earthquakes in accordance with recommended and generally accepted good engineering practices. The EIS recommends, and Environmental Condition 32 requires, that drawings and calculations be provided for the Prudhoe Bay Treatment Plant and Liquefaction Facilities. In addition, Environmental Condition 133 requires AGDC to file design details of the seismic monitoring onsite.[106] AGDC has also committed to monitor the Alaska Earthquake Center seismic network for earthquakes and initiate facility inspections or repairs based on real-time seismic data.[107]

50. Mass wasting and landslides in the project area are most likely to occur along about 33.4 miles of the Mainline Pipeline in the Brooks Range and near the Alaska Range. AGDC indicates it would employ additional mitigation measures to minimize or mitigate impacts in areas with moderate to high potential for soil liquefaction, including the use of heavy-walled pipe, ground improvements, and pressure relief wells.[108] Because liquefaction hazards could result from permafrost degradation, AGDC would implement the measures identified in the *Pipeline Operation and Maintenance Plan* to assess and remediate impacts on permafrost to monitor, mitigate, and manage potential permafrost degradation and resulting impacts, including soil liquefaction and other forms of mass wasting.[109]

51. At the Liquefaction Facilities, the primary mass wasting hazard is erosion of the coastal bluff. To avoid potential impacts, LNG plant structures and foundations for the marine facilities would be set back at least 300 feet inland, erosion and sediment controls would be installed, and a stormwater collection and management system would be implemented.[110] Long-term mitigation would include monitoring the bluff slope and shoreline to determine if additional measures are needed to maintain or enhance

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[105] *Id*. at 4-44.

[106] This Condition has also been revised to clarify that it applies only to the Liquefaction Facilities.

[107] *Id*.

[108] *Id*.

[109] *Id*.

[110] *Id*.

stability.[111] Coastal flooding and erosion could be a concern for the gas treatment facility, which would be sited close to the Beaufort Sea coastline.[112] To address this concern, the EIS recommends, and Environmental Condition 41 requires, AGDC to file a site-specific analysis for coastal erosion and propose a prevention and mitigation plan prior to construction.

52. Acid rock drainage and metal leaching (ARD/ML) processes result from exposure of sulfide minerals and coal to oxygen and water, which oxidizes metals and releases chemical constituents that lower the pH (i.e., acidify) of the drainage. The weathering process that results in ARD/ML may be naturally occurring or triggered by increased exposure of bedrock through trenching or the development of quarries. AGDC identified potential ARD/ML locations that would require site-specific evaluations to be completed prior to construction and will develop a project-wide *ARD/ML Management Plan* based on the results.[113] The EPA recommended monitoring in areas of moderate ARD/ML potential. The EIS recommends, and Environmental Condition 17 requires, AGDC to file a modified project-wide *ARD/ML Management Plan* that includes details for surface and groundwater monitoring in areas of moderate ARD/ML potential. Additionally, AGDC's updated *Gravel Sourcing Plan and Reclamation Measures* would include measures for testing material sites for potential ARD and presence of contaminants, such as mercury, arsenic, antimony, etc., that may render fill material unsuitable for construction of granular fill pads and access roads.[114]

53. AGDC reviewed geotechnical data for the five trenchless crossing locations[115] along the Mainline Pipeline to assess the viability of two potential installation technologies and selected directional micro-tunneling as the appropriate method for all crossing.[116] Prior to construction of the Mainline Facilities,[117] AGDC would file with the Commission, for review and approval final installation design and drilling plans for each

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[111] *Id*.

[112] *Id*. at 4-41.

[113] *Id*. at 4-46.

[114] *Id*.

[115] Middle Fork Koyukuk, Yukon, Tanana, Chulitna, and Deshka Rivers.

[116] Final EIS at 4-51.

[117] Mainline Facilities comprises the eight compressor stations, Theodore River Heater Station, and the Mainline Pipeline.

directional micro-tunneling crossing.[118] The subsurface profile for the Deshka River directional micro-tunneling crossing is projected based on two soil borings; the EIS recommends, and Environmental Condition 18 requires, AGDC to file a revised feasibility crossing study that provides updated site-specific geotechnical information for the Deshka River with additional borings conducted at the proposed crossing location.

54. The final EIS found that, based on AGDC's proposed mitigation measures and design criteria, compliance with applicable regulatory approvals and requirements, and Commission staff's recommended measures, the potential impacts on the AGDC Project from geologic hazards and other natural hazards will be minimal, and the AGDC Project will not significantly impact geologic resources.

2. <u>Soils</u>

55. Soils within the project footprint were evaluated to identify permafrost and major soil characteristics that could affect construction or increase the potential for construction-related impacts on soils. Soil interpretations at the broadest scale are based on Major Land Resource Areas (MLRA) designated by the U.S. Department of Agriculture. The major soil resource concerns identified by the U.S. Department of Agriculture in the 10 MLRAs crossed by the project are disturbance of permafrost soils, wind and water erosion, and soil compaction. Various project construction activities, such as clearing, grading, granular fill placement, and excavations, would affect soil resources. The project would be constructed over the course of about eight years, which would amplify soil impacts typical to pipeline and aboveground facility construction. AGDC would monitor construction, implement industry Best Management Plans (BMP) and project-specific plans to prevent, reduce, and mitigate adverse effects on soils. These plans include: *Project Upland Erosion Control, Revegetation, and Maintenance Plan* (*Project Plan*)*; Spill Prevention, Control, and Countermeasure Plan* (*Spill Prevention Plan*); *Revegetation Plan; Winter and Permafrost Construction Plan; Blasting Plan*; and *Geologic Hazards Assessments*. These plans are designed to accommodate varying field conditions while maintaining standards for protecting soil resources.

56. To minimize impacts from surficial soil erosion, AGDC would implement the measures identified in the *Project Plan* and *Winter and Permafrost Construction Plan*.[119] Right-of-way pre-clearing activities (cutting down trees and brush) would occur in the winter season between 1 and 1.5 years prior to each scheduled construction season. While limiting pre-clearing to the winter season and leaving the understory vegetation and organic mats in place would reduce effects on permafrost, permanent impacts would

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[118] *Id*. at 4-53.

[119] *Id*. at 4-110.

still occur given the time elapsed between pre-clearing and active construction.[120] Temporary erosion and sediment controls would be installed before the onset of conditions that could cause erosion (e.g., spring thaw) or immediately after initial ground disturbance. The controls would be left in place and repaired, replaced, or supplemented, as needed, through the end of construction.

57. AGDC assessed piping erosion[121] based on soil erodibility and topographical conditions, such as where fine-grained cohesionless soils exist within floodplain areas, both close to waterbodies and near the toes of steep slopes. Mitigation measures to be used in areas identified with the potential for piping erosion include the use of subdrains to control meltwater and groundwater recharge, as well as prevent the development of a hydraulic gradient within the erodible soils underneath the pipe.[122]

58. However, AGDC did not complete the same level of analysis for piping erosion potential for the portion of the Mainline Pipeline between MPs 536.1 and 544.3.[123] Accordingly, the EIS recommends, and Environmental Condition 21 requires, AGDC to file an updated assessment of piping erosion potential between MPs 536.1 and 544.3 using the same methodology used for the rest of the Mainline Pipeline (Onshore Geohazard Assessment Methodology and Results summary). If any new areas of piping erosion potential are identified, AGDC would be required to implement the same

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[120] The final EIS at 4-1 discusses the four levels of impact duration that were considered in the analysis: 1) temporary impacts generally occur during the 8-year construction period, with the resource returning to pre-construction condition immediately after restoration or within a few months to a year following the installation of permanent erosion control measures; 2) short-term impacts could continue for up to five years following installation of permanent erosion control measures; 3) long-term impacts would persist for more than five years and for up to thirty years after installation of permanent erosion control measures, with the affected resource eventually recovering to pre-construction conditions; and 4) a permanent impact would not return to pre-construction conditions during the life of the project, which AGDC defines as 30 years. Permanent impacts could also extend beyond the life of the project. For example, the clearing of mature forests would be a permanent impact because it would take several decades for these habitats to attain their pre-construction conditions.

[121] Piping erosion occurs when water conveys fine sands and silts in certain non-cohesive soils between coarse soil particles, which results in fines being removed from the soil matrix, which could lead to the development of voids underneath the pipeline.

[122] *Id*. at 4-113.

[123] *Id*.

mitigation measures that will be implemented for other areas with the potential for piping erosion.

59. Contamination from spills or leaks of fuels, lubricants, and coolant from construction equipment could adversely affect soils. AGDC's *Spill Prevention Plan* specifies measures to minimize the potential for soil contamination from spills or leaks.[124] Facility-specific Spill Prevention Plans would be developed by construction contractors. AGDC and its contractors would use these Spill Prevention Plans to minimize accidental spills of materials that could contaminate soils, and to ensure that inadvertent spills are contained, cleaned up, and disposed of as quickly as possible and in an appropriate manner.[125]

60. AGDC's *Unanticipated Contamination Discovery Plan* provides general procedures for the unanticipated discovery of contamination on land or water and outlines contamination discovery, initial response procedures, site characterization, and hazard assessment to determine the extent, nature, and disposition of the contamination; proper agency and local official notifications; and recordkeeping procedures.[126] Depending on the extent and characteristics of the identified contamination, AGDC would either seek a route adjustment to avoid the contamination or make plans with the appropriate landowner and Alaska Department of Environmental Conservation (ADEC) for excavating or reducing the contamination with disposal at an approved waste disposal site.[127] AGDC would consult with ADEC and/or the EPA if a site is characterized as hazardous.[128]

61. For the Marine Terminal Material Offloading Facility construction, dredging would be required. Dredging activities would cause temporary increases in turbidity and sedimentation in Cook Inlet. AGDC would file a *Project Dredging Plan* with the Commission for review and written approval prior to construction. The State of Alaska observed that, given the history of the Prudhoe Bay area, a plan should be in place in case historical contamination is found during dredging. The *Unanticipated Contamination Discovery Plan* does not include specific measures that would be taken for the unanticipated discovery of contaminated sediments in a marine environment.

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[124] *Id*. at 4-119.

[125] *Id*. at 4-119.

[126] *Id*. at 4-120.

[127] *Id*.

[128] *Id*.

Accordingly, the EIS recommends, and Environmental Condition 22 requires, that AGDC file an updated plan that indicates the measures that will be taken if contaminated sediments are discovered in marine environments, including the appropriate agency notification requirements.[129]

62. Clearing, grading, and trenching of the construction work area would affect permafrost and thermal energy balance due to the removal of vegetation and snow cover. The effects of permafrost alteration due to construction and operation of the Mainline Pipeline could include subsidence and thermokarst[130] development; solifluction,[131] soil creep, and thawed-layer detachment on steep slopes; and increased erosion.[132]

63. To minimize permafrost impacts, the construction measures in the *Winter and Permafrost Construction Plan* include: constructing in thaw-sensitive permafrost during the winter where possible; use of granular work pads or temporary ice pads along the right-of-way, extra works spaces, and aboveground facilities, and for other construction; snow management; and use of temporary and permanent erosion and sediment controls.[133]

64. AGDC would use granular fill in areas of thaw-sensitive permafrost to stabilize the Mainline Pipeline right-of-way, additional temporary workspace areas, and access roads.[134] AGDC would place the granular fill between one and three feet deep to construct a pad. The specific amount of granular fill in any location would depend on the permafrost thaw-susceptibility as well as the construction season, with the summer

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[129] Environmental Condition 22 also requires AGDC to notify NPS in the event of an unanticipated discovery of contamination on NPS property.

[130] Thermokarst is a land surface characterized by very irregular surfaces of marshy hollows and small hummocks formed as ice-rich permafrost thaws. Areas of thermokarst could develop where flowing water produces thermal erosion, a dynamic process that involves the thawing of ground ice, and by mechanical erosion (i.e., hydraulic transport of soils).

[131] "Solifluction" is the gradual movement of wet soil or other material down a slope, especially where frozen subsoil acts as a barrier to the percolation of water. Final EIS at 1181, n.190.

[132] *Id*.

[133] *Id*. at 4-88.

[134] *Id*. at 2-60.

construction season requiring the deepest fill (up to three feet) to prevent rutting.[135] However, the final EIS notes that, based on past construction issues in permafrost in Alaska, and staff's own review of scientific research, staff could not conclude with certainty that granular pads would protect permafrost or minimize impacts on wetlands.[136] While the final EIS finds that granular fill would provide a more stable and safe construction working surface, the installation of granular work pads, particularly for the Mainline Facilities, would conduct solar radiation to the underlying permafrost, thereby causing changes to the subsurface thermal regime and drainage patters in thaw-sensitive areas.[137]

65. To further address the impacts to permafrost associated with granular work pads, the EIS recommends, and Environmental Condition 19 requires, AGDC to assess if winter construction would be feasible in low slope areas (0 to 2 percent grade) proposed for certain construction activities as an alternative to the use of granular fill; and use timber/synthetic mats in place of granular fill in wetlands and uplands underlain by thaw-stable permafrost in low slope areas.

66. AGDC has also worked with the ADNR to determine areas where surface organic layer segregation could occur. AGDC's goal of organic layer segregation is for land stabilization through reestablishment of vegetation. However, AGDC's proposed project *Revegetation Plan* does not currently provide a comprehensive set of information on surface segregation. AGDC would provide a final *Revegetation Plan* that would incorporate all surface layer segregation information, including the milepost ranges in which surface layer segregation would be executed between MPs 0 and 607, and an analysis and justification of where the surface layer would and would not be segregated between MPs 607 and 807. In areas where the surface organic layer would not be segregated, the organic layer would be mixed with subsoil layers during stockpiling and soils would not be put back into the trench in the same order as they were removed, thereby causing permanent impacts on permafrost. The final *Revegetation Plan* would be filed with the Commission for the review and written approval prior to construction of the Mainline Facilities.

67. As discussed in the final EIS, revegetation on gravel and rocky soil could be enhanced by using a higher proportion of fines or small particles in the granular fill. AGDC plans to use granular fill consisting of sands and gravels with less than 12 percent

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[135] *Id*.

[136] *Id*. at 4-89.

[137] *Id*.

fines.[138] Given that a greater proportion of fines could improve the likelihood for successful plant establishment, the EIS recommends, and Environmental Condition 20 requires, AGDC, prior to placement of any granular fill, to conduct aggregate testing to select granular fill with at least 20-percent fines for the surface layer used on all construction workspaces, and file the results of the aggregate tests in its construction status reports filed with the Commission.

68. In its comments on the draft EIS, AGDC asserted that a higher percentage of fine material in the granular fill would not be operationally sound and would potentially increase fugitive dust and increased sediment in runoff without improving the potential for revegetation. As discussed in the final EIS, the 20 percent fine is consistent with what is used in the surface layer for gravel roads; a lower percentage of fines can still be used in the base layer to provide the necessary load capacities; and the potential for fugitive dust, increase sediment in runoff would not likely be any greater than what would occur with an exposed soil surface in construction areas without granular fill.[139] Accordingly, we find the potential for increased plant establishment with the higher percentage of fines warrants our requirement for its use.

69. Operation of the Mainline Pipeline could also cause long-term changes to the thermal energy balance throughout the soil profile. Frost bulb and/or frost heave formation[140] could occur where the pipeline transitions from frozen to unfrozen soil and ground ice development occurs due to the chilled pipeline, placing additional tensile or compressive strain on the pipeline. Site-specific mitigation measures would be developed during the detailed design phase of the project, implementing the Geohazard Mitigation Approach, and may include additional insulation, to maintain unfrozen soils around the pipeline; and concrete coating or other buoyancy compensation where the pipeline is buried across saturated floodplains or active channels.

70. Thawing of discrete massive ice or excess ice features within permafrost can lead to thermokarst development. The settlement of thermokarst topography can then cause changes to natural drainage patterns, increase erosion, and increase thaw induced slope instability. AGDC identified about 34 miles of the Mainline Pipeline that would require the use of heavy-walled steel and/or additional design and monitoring requirements per

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[138] *Id.* at 4-91.

[139] *Id.*

[140] Frost bulb and/or frost heave formation are typically long-term processes driven by freezing of previously unfrozen soils. During construction, there is no thermal process other than the normal seasonal freeze/thaw cycle driving the freezing of unfrozen soils. Thus, the short-term risk of frost bulb and/or frost heave formation during construction is very low.

the PHMSA-approved Strain-Based Design Special Permit (Special Permit). According to the Special Permit conditions, additional areas of permafrost resulting in thaw settlement and pipe strains could be identified as project engineering continues and could be added to the Strain-Based Design Segments by a Design Change Process for the Special Permit. Thermokarst also has the potential to occur adjacent to granular fill work pads, and permafrost thaw could extend up to 20 feet outside of the construction right-of-way. AGDC would monitor conditions adjacent to granular work pads as outlined in the proposed *Revegetation Plan*. AGDC would also manage trench groundwater flow by installing periodic ditch plugs or water bars to stop ditch flow and direct ground and surface water away from the pipeline. Additionally, the pipe would be bedded with thaw-stable, non-frost susceptible materials that would minimize permafrost degradation, pipe thaw settlement, and surface slumping.

71. Continuous monitoring and operation of project facilities would be conducted through the SCADA system, a computer system used for gathering and analyzing data from real-time systems and operating remote facilities. AGDC would control gas temperature during operation of Mainline Facilities by heating and/or cooling gas at compressor stations and using gas heaters and adjusting gas temperatures for seasonal variations in discontinuous permafrost areas to match ground temperatures to the extent possible. AGDC has also developed a *Project Pipeline Operation and Maintenance Plan* that describes operational monitoring methods that would be used on the Mainline Pipeline to determine if changing conditions (including permafrost changes) create an unacceptable risk to the pipeline. The plan provides that surveillance for the Mainline Pipeline would be at intervals not to exceed 45 days and would occur a minimum of 12 times each year.

72. The Prudhoe Bay Treatment Plant would be constructed on granular pads with a minimum thickness of five feet. Construction of associated facilities would incorporate granular work pads, piles, Vertical Support Members (VSM), and thermosiphons to preserve the active layer thickness and underlying permafrost. Operational impacts on permafrost would be minimized by use of VSM technology for the Point Thomson Unit Gas Transmission Line and Prudhoe Bay Unit Gas Transmission Line and aboveground pipelines for the Prudhoe Bay Treatment Plant. AGDC intends to monitor, mitigate, and manage potential permafrost degradation and the resulting impacts at VSMs as part of its *Project Pipeline Operation and Maintenance Plan*.

73. The primary construction concern, with respect to soil integrity, for the Liquefaction Facilities would be soil erosion as no permafrost soils are present at the site. The majority of operational impacts on soils associated with the Liquefaction Facilities would be the conversion of soil to impervious surfaces. Comments were received during the public scoping period about bluff erosion in the area of the Liquefaction Facilities. AGDC assessed existing bluff erosion structures and proposed that the Marine Terminal Material Offloading Facility be constructed using a combi-wall structure from the toe of

the bluff extending offshore and tied back to a sheet pile anchor wall that would be buried under the Material Offloading Facility fill. During operation, AGDC has proposed to conduct annual Light Detection and Ranging (LiDAR) surveys to identify significant changes from baseline conditions along the bluffs.[141] AGDC has identified potential mitigation measures for bluff erosion, including the use of steel sheet piles, armor rock, gabion structures, geocells, geomat, and sand/gravel bags, which would add to the existing structures to help reduce bluff erosion rates.

74. With implementation of the measures discussed above, the final EIS concludes that most project effects on soils would be less than significant; however, the long-term to permanent impacts on permafrost and loss of soils due to granular fill placement, particularly for the Mainline Facilities, would be significant.[142]

3. Water Resources

75. Project construction and operation would result in minor impacts on groundwater resources. The project would cause permanent, but minor, alterations to surface and groundwater hydrology due to impacts on permafrost. Impacts on groundwater would be adequately minimized through AGDC's implementation of proposed mitigation measures, AGDC construction monitoring, and compliance with federal, state, and local regulatory approvals and requirements.

76. Groundwater uses for the project would be primarily related to construction and hydrostatic testing of the Mainline Facilities. No groundwater would be used during construction or operation of the Prudhoe Bay Treatment Plant or Liquefaction Facilities.[143] For the Mainline Facilities, given the remoteness of the construction camps and the monitoring that would take place at wells, and because groundwater volumes would be recharged each year during spring thaw, the potential groundwater drawdown impacts caused by water use at construction camps would likely be minor and temporary.[144]

77. Surface drainage and groundwater could be affected by various construction activities, such as clearing, grading, trenching, and site preparation. Groundwater contamination could result from spills of fuel, oil, or other hazardous materials during

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[141] *Id*. at 4-119.

[142] *Id*. at 5-7.

[143] *Id*. at 4-226.

[144] *Id*.

project construction and operation. To avoid or minimize impacts, AGDC would implement the fueling, storage, containment, and cleanup measures identified in its *Spill Prevention Plan*, and the hazardous material handling procedures provided in its *Procedures and Waste Management Plan.*[145] AGDC would also implement: a *Groundwater Monitoring Plan* in key areas near known contaminated sites; the *ARD/ML Management Plan* that includes mitigation and monitoring measures in areas of high ARD/ML potential; and a *Water Well Monitoring Plan.*[146] In addition, the ARD/ML condition mentioned above would further mitigate impacts on groundwater resources.

78. The Mainline Pipeline would require 553 waterbody crossings, and the Point Thomson Unit Gas Transmission Line would require 106 waterbody crossings. Project construction and operation would result in minor and temporary impacts on surface water quality and streamflow and impacts on freshwater resources would be adequately minimized because AGDC would adhere to the measures included in the *Project Plan and Procedures*, *Spill Prevention Control, and Countermeasure Plan*, *Stormwater Pollution Prevention Plan*, *Fugitive Dust Control Plan*, *Waste Management Plan*, and *Revegetation Plan*.

79. Infrastructure such as granular pads, access roads, pipe storage yards, and disposal sites would permanently fill a portion of some ponds and lakes.[147] Project activities at mainline additional work areas, the Prudhoe Bay Treatment Plant, and the Liquefaction Facilities would affect about 208 acres of waterbodies.[148] AGDC has stated that it would avoid placing permanent granular fill in streams and rivers; however, four additional work areas (two pipe storage yards and two disposal sites) could encroach upon four individual waterbodies[149] where placement of granular fill or spoil could interrupt streamflow.

80. To avoid affecting water flow and quality within these four waterbodies, the EIS recommends, and Environmental Condition 23 requires, AGDC to restrict the placement

[145] *Id.* at 4-155.

[146] *Id*. at 4-222.

[147] *Id*. at Appendix I, Tables I-5 and I-7.

[148] *Id*. Additional information on the Liquefaction Facilities is provided in section 4.3.2.5 of the final EIS.

[149] *Id*. at Appendix I, Table I-5.

of granular fill, spoil, or other materials in these waterbodies, and to file, if relevant, site-specific plans it will use to preserve water flow and quality within the affected streams.

81. Construction activities within marine waters, such as dredging and construction of in-water structures, would result in short-term and localized turbidity and sedimentation that would dissipate, resulting in less than significant impacts. Nearshore construction activities in Prudhoe Bay and Cook Inlet could result in sedimentation in marine waters due to erosion from stormwater runoff and dewatering, but AGDC would implement erosion measures in its *Stormwater Pollution Prevention Plan* (*Stormwater Prevention Plan*) to reduce or avoid impacts and implement Best Management Practices in accordance with the *Project Wetland and Waterbody Construction and Mitigation Procedures* (*Project Procedures*) and ADEC's *Best Management Practices for Gravel/Rock Aggregate Extraction Projects User Manual*.[150]

82. Offshore construction of the Mainline Pipeline through Cook Inlet via the bottom lay method would result in turbidity in the immediate vicinity of the pipe and associated anchoring activities for construction vessels.[151] The increases in turbidity and sediment dispersal would be minimal and short term in nature. Beyond the shoreline crossings, the Mainline Pipeline would remain as a permanent feature on the bottom of Cook Inlet.[152]

83. Surface water withdrawals would be used during construction and operation of all project facilities. Project construction would require the use of surface water for hydrostatic testing, directional micro-tunneling activities, ice road construction, potable water, and activities such as dust control. Operating the project would require water for a variety of activities, including hydrostatic testing, emergency repairs, and potable water. With implementation of the mitigation measures described above, AGDC's commitments, and compliance with applicable permits, impacts from surface water withdrawal, use, and discharge would be minor and short term.

4. **Wetlands**

84. Approximately 3,535 acres of wetlands would be temporarily affected by construction and operation of the project; approximately 8,225 acres of wetlands would be permanently affected, which includes about 6,220 acres of permanent granular fill and about 195 acres of palustrine forested wetlands converted to palustrine emergent and/or palustrine

[150] *Id*. at 4-156.

[151] *Id*. at 4-226.

[152] *Id*. at 4-227.

scrub/shrub wetlands.[153] The remaining 1,809 acres of wetlands would be permanently affected by material sites, disposal sites, a water reservoir, and a stormwater pond.[154] Although AGDC proposes to restore some of the affected wetlands, depending on the construction mode and growing conditions, impacts on the wetlands would range from short term to permanent.[155]

85. Construction of granular fill pads for infrastructure would occur across the project area and result in the permanent loss of wetlands, i.e., extending beyond the nominal design life of the project. The conversion of wetlands to uplands through granular fill placement would affect adjacent wetlands by fragmenting them into smaller sections and changing natural drainage patterns. Wetlands in the Arctic Coastal Plain and Arctic Foothills Subdivisions are known to store large quantities of carbon, which provide carbon sequestration on a massive scale.[156] Wetland loss from granular fill placement in these areas would reduce the capacity to sequester and transform carbon. Adjacent wetlands could also experience increased turbidity and sedimentation because fine particles would be transported from granular fill to adjacent wetlands by stormwater runoff during construction and operation.[157]

86. Compensatory mitigation would likely be required by the COE to offset the loss of wetland and aquatic resource functions for any unavoidable impacts on wetlands or aquatic resources. Methods of providing compensatory mitigation include restoration, establishment, enhancement, or preservation as authorized through the issuance of Department of the Army permits pursuant to Clean Water Act (CWA) section 404 and/or River and Harbors Act section 10.[158] Pursuant to NPS requirements, wetland compensatory mitigation for impacts under NPS regulatory authority would be consistent with the NPS Director's Order 77-1.57.[159] AGDC provided a *Project Wetland Mitigation*

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[153] *Id*. at Table 4.4 3-1.

[154] *Id*. at 4-233.

[155] As noted above, an impact is categorized as permanent impact if the wetland would not return to pre-construction conditions during the life of the project, which AGDC defines as 30 years.

[156] *Id*.

[157] *Id*.

[158] *Id*. at 4-250.

[159] *Id*.

Plan to the COE for review. AGDC is consulting with the COE and other resource management agencies to determine the appropriate form of mitigation offsets for unavoidable impacts on waters of the United States, including wetlands.

5. **<u>Vegetation</u>**

87. Constructing the project would affect about 26,054 acres of vegetation, including 12,440 acres of forest, 8,080 acres of scrub, and 5,534 acres of herbaceous vegetation.[160] These values encompass the smaller areas of operational impact areas that would affect about 7,596 acres, including 3,282 acres of forest, 2,214 acres of scrub, and 2,101 acres of herbaceous vegetation.[161]

88. Project construction and operation would have temporary to permanent effects on vegetation. Impacts associated with all project facilities would include the permanent loss of vegetation due to various types of disturbance, including: the placement of granular fill; installation of aboveground facilities; excavation for material sites; and construction of disposal sites.[162] Most impacts would be minimized with implementation of AGDC's various project-specific plans, including the *Project Plan, Project Procedures, Stormwater Prevention Plan, Revegetation Plan, Spill Prevention Plan, Invasives Plan, Invasive Species Prevention and Management Plan, Winter and Permafrost Construction Plan*, and *Revegetation Plan*, during both construction and operation.

89. Impacts on scrub and herbaceous plant communities would be less than significant based in part on the small areas affected relative to the larger watersheds and their shorter recovery time relative to forest communities. Impacts on other vegetation resources, including rare plants and rare plant communities, aquatic vegetation, and pollinator plant species, would likely not be significant due to a number of factors, including the small areas affected relative to the larger watersheds or the total distribution of the plant community type or species.[163] The final EIS concludes that AGDC's implementation of the EIS recommended mitigation measures along with AGDC's proposed commitments,

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[160] *Id*. at Table 4.5.2-1.

[161] For context, the project would affect less than 1 percent of the estimated 2.1 million acres of forest, 1.7 million acres of scrub, and 0.7 million acres of herbaceous vegetation in the HUC12 watersheds crossed by the project based on the USGS Gap Analysis Project (GAP)/LANDFIRE National Terrestrial Ecosystems land cover data (2018). Final EIS at 4-253.

[162] *Id*. at 4-253.

[163] *Id*.

would contribute to reduced impacts on scrub and herbaceous plant communities, rare plants and rare plant communities, aquatic vegetation, and pollinator plant species.

90. Project construction and operation would result in the permanent loss or conversion of about 8,512 acres of forest, 4,293 acres of scrub, and 2,199 acres of herbaceous vegetation.[164] These permanent impacts would be due to the effects of fill (including the permanent placement of granular fill), excavation (e.g., for material sites), and long-term vegetation maintenance in the permanent Mainline Pipeline right-of-way.

91. Project impacts would be greatest for forest habitats both in terms of quantity and duration since such habitats would take the longest time to recover in the temporary construction workspace (25 to 100 years)—potentially resulting in about 3,891 acres of additional permanent impacts—or would be permanently converted to upland, herbaceous, and scrub communities in the permanent Mainline Pipeline right-of-way.[165] Impacts on forest communities would be significant given the amount of habitat affected and the longer recovery period for this vegetation type.[166] Given that edge effects would not necessarily result in the loss of adjacent forest communities, the impacts from edge effects themselves would not be significant. However, they would result in the long-term to permanent alteration of forest habitat adjacent to the right-of-way and access roads, contributing to the overall significant impacts on forest communities [167]

92. In addition, the potential introduction and dispersal of non-native invasive plant species into a relatively pristine environment, particularly along the Mainline Pipeline right-of-way, could have a significant impact on native plant communities.[168] AGDC proposes measures to minimize potential impacts from non-native invasive plant species, including implementation of the *Invasive Species Prevention and Management Plan* and *Revegetation Plan* during both construction and operation. AGDC's proposal also includes seeding areas with non-native invasive plant species-infestations within the first growing season following construction to reduce the establishment and/or spread of non-

[164] *Id*. at 4-254.

[165] *Id*. at 4-265.

[166] *Id*. at 4-282.

[167] *Id*. at 4-1180.

[168] *Id*. at 4-268.

native invasive plant species prior to natural recruitment. With these measures, impacts will not be significant.[169]

6. Wildlife Resources

93. The Alaska LNG Project would affect about 26,159 acres of terrestrial wildlife habitat.[170] More than 40 terrestrial large and small mammal species are found in the habitats within the project area including moose, black bear, polar bear, brown bear (including grizzly bears, which are a subspecies of brown bear), caribou, Dall sheep, muskoxen, gray wolf, wolverine, fox, Canadian lynx, otter, coyote, and American beaver. Three species—Alaska marmot, American water shrew, and little brown myotis—are classified as sensitive by the Alaska Natural Heritage Program.[171]

94. Construction and operation would affect terrestrial wildlife due to loss or alteration of habitat. Some of these habitats would also be fragmented and experience edge effects. Affected habitats include arctic tundra, boreal forest, and transition forest, as well as the smaller habitat types that occur within them, such as wetlands, riparian areas, meadows, bogs, and scree slopes.[172] Wetland, riverine, and lake habitats would also be affected throughout the project area.

95. Direct injury or mortality of terrestrial wildlife could occur due to construction or maintenance activities or vehicle and equipment collisions. Clearing and grading could affect hibernating mammals and less mobile species. Collision with vehicles and equipment could occur within construction work areas and on access roads or along public roads and highways, but wildlife would be somewhat acclimated to existing traffic on these roads. AGDC will implement measures to minimize collision risks, such as limiting vehicle speeds.

96. Construction of the numerous aboveground facilities (including most new access roads) would result in the permanent loss of wildlife habitat. Temporary loss would occur in areas restored to natural conditions, although recovery times could range from years to decades depending on vegetation type and region. Permanent habitat loss would occur at aboveground facilities, and granular fill sites, along access roads, and in areas where cover types, such as forest, are modified for right-of-way maintenance.

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[169] *Id*.

[170] *Id*. at Table 4.6.1-2.

[171] *Id*. at 4-283.

[172] *Id*. at 4-288.

97. During construction, trenching for the Mainline Pipeline could temporarily block animal movements across the right-of-way, which could disrupt seasonal activities or migration patterns, particularly for large mammals. To reduce these potential impacts, AGDC would coordinate with the Alaska Department of Fish and Game and the FWS to develop procedures to facilitate wildlife movement and minimize migration disruptions due to construction. Where practicable, AGDC would schedule excavation activities to avoid major migrations.

98. Construction and operational activities would generate noise that could affect terrestrial wildlife, although most animals would be capable of avoiding noise that could be physically damaging. impacts on wildlife would be mostly behavioral, such as displacement to adjacent habitats, but project noise could also disrupt breeding, hibernation, predation, and other temporal patterns. However, construction impacts would be short term and localized; whereas, operational impacts would be long-term to permanent, and localized. [173]

99. Terrestrial wildlife could be affected by the presence of humans and use of project facilities, particularly in remote areas with limited human populations. Impacts could include behavioral changes, a decrease in reproduction success due to stress, and mortality from increased hunting and poaching. To minimize impacts, construction camps and waste management systems would be designed to reduce wildlife attraction to camps by food and refuse. Workers would be trained on good housekeeping practices, including implementation of the *Project Waste Management Plan*, to reduce potential for interactions with wildlife. With the implementation of the project construction and restoration plans, the final EIS concludes that impacts described above would be less than significant on most terrestrial species.

100. During scoping, the residents of Nuiqsut and Kaktovik, two communities on the North Slope, expressed concerns about the impacts of oil and gas development, including the proposed project, on caribou and caribou movements.[174] Both villages harvest caribou year-round. Nuiqsut's and Kaktovik's terrestrial subsistence use areas overlap

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[173] *Id*.

[174] Caribou have high economic and recreational value and are an important source of income and nutrition, particularly for these communities. Of all terrestrial mammals harvested, caribou typically represent the most intensely harvested subsistence resource. On the North Slope Region, marine mammal and large land mammal harvests comprise the majority of the total subsistence catch (about 40 percent each). There are years when no bowhead whales are harvested in Nuiqsut and Kaktovik. During these years, Nuiqsut and Kaktovik have historically increased their reliance on the harvest of other resources including large land mammals, such as caribou. *Id*. at 4-755.

with the Prudhoe Bay Treatment Plant (including the Point Thomson Unit Gas Transmission Line) and Mainline Pipeline.

101. The Central Arctic Herd of caribou has the only calving and insect relief habitats affected by the project.[175] The Mainline Pipeline and the Point Thomson Unit Gas Transmission Line combined would cross about 94.2 miles and about 2,270 acres of spring calving habitat and 1,203 acres of insect relief habitat for the Central Arctic Herd.[176] Affected areas would be covered by gravel roads and pads, a material site, a reservoir, and pipelines, resulting in permanent habitat loss. For the Prudhoe Bay Treatment Plant, which includes the Point Thomson Unit Gas Transmission Line that would be elevated 7 feet aboveground, disturbances to these habitats from project operation would be permanent, including the change in the landscape created by the Point Thomson Unit Gas Transmission Line.[177] Because the Point Thomson Unit Gas Transmission Line would be built above ground, it could serve as a barrier during project operations to caribou migration between habitat areas or within specialized habitats.[178] Additionally, unlike the Mainline Facilities, the 62.5-mile-long Point Thomson Unit Gas Transmission Line would run parallel to Prudhoe Bay, which is critical area for insect relief for the Central Arctic Herd.

102. As discussed in the final EIS, a synthesis of previous studies on the effects of pipeline height on caribou crossing success found that older pipelines (i.e., those constructed before the minimum height of five feet above ground level was stipulated by the State of Alaska) constitute barriers to caribou crossings in the absence of crossing ramps.[179] Generally, pipelines elevated to the minimum height of 5 feet are high enough to accommodate caribou crossings during snow-free periods. In the Prudhoe Bay area, the snow-free period begins around June, about the same time as the beginning of the Central Arctic Herd's calving period. Additionally, a portion of the Central Arctic Herd's winter habitat overlaps with the western end of the Point Thomson Unit Gas Transmission Line.

103. While there is limited data on pipeline crossings by caribou in the winter, the available evidence indicates that pipeline heights in the range of seven to eight feet are

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[175] *Id*. at Table 4.6.1-6.

[176] *Id*. at 4-305 – 306; *see also* Table 4.6.1-7.

[177] *Id*. at 4-305.

[178] *Id*. at 4-306.

[179] *Id*. at 4-306.

more likely to be crossed by caribou during those periods than pipelines at lower heights. As noted above, the Point Thomson Unit Gas Transmission Line would be elevated to a height of seven feet above ground.[180] Constructing pipelines at this height would serve to reduce impacts on caribou, but caribou potentially could still exhibit behaviors such as hesitation or avoidance.[181]

104. Additionally, caribou individuals may react differently to infrastructure after repeated exposure, but that effect (habituation) is difficult to measure. While researchers have documented that caribou within the Central Arctic Herd appear to have habituated to certain aspects of the existing infrastructure, factors such as traffic and insect harassment may influence their future behavior.[182] Impacts of general infrastructure on caribou distribution, habitat use, and population trends are not well understood, but studies conclude that roads likely alter caribou migration and that distance to infrastructure may play a role in influencing caribou behavior.

105. Although the final EIS found that drawing definitive conclusions about the impact of the project on caribou movement is not possible at this time, it concluded that the project's permanent impacts on sensitive habitats, along with the project location at the center of the Central Arctic Herd's range, would contribute to significant impacts on the Central Arctic Herd.[183] This conclusion was based on a review of previous studies and comments from stakeholders, including from Alaska subsistence communities that are dependent on caribou.

106. In comments on the draft EIS, AGDC and others contend that the impact assessment on the Central Arctic Herd, was overstated and that temporary, rather than significant, impacts on the Central Arctic Herd would occur.[184] AGDC and others assert that the project footprint would represent a small percentage of available caribou habitat and that project activities would occur when the Central Arctic Herd is not present.[185] However, as discussed in the final EIS, various project facilities—including permanent facilities—would be located within sensitive habitat for the Central Arctic Herd

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[180] *Id*. at 4-291.

[181] *Id*. at 4-306.

[182] *Id*.

[183] *Id*. at 4-312.

[184] *Id*.

[185] *Id*. at 4-306.

throughout the year and the Mainline Pipeline would bisect the known occupancy range for the herd.[186]

107. We concur with the findings set forth in the final EIS but find that additional measures are warranted to address the significant impacts on the Central Arctic Herd. Accordingly, we will require in Environmental Condition 24 that AGDC, following construction of the Prudhoe Bay Treatment Plant and Point Thomson Unit Gas Transmission Line, conduct seasonal monitoring for three years to track caribou herd movement and determine if project infrastructure is creating a barrier to caribou movement. To allow conclusions to be drawn regarding any potential changes, AGDC will also be required to conduct baseline monitoring of caribou movement prior to the start of construction of the Prudhoe Bay Treatment Plant and Point Thomson Unit Gas Transmission Line. No later than six months after completion of the three-year study, AGDC must file a report describing the results of the monitoring, and recommendations to minimize or mitigate any identified issues with caribou movement related to the project, for further consideration and potential action by the Commission.

108. Alaska is home to more than 500 species of birds including raptors, waterbirds, passerines, and upland birds.[187] Birds use the various habitats in the project area for resting, staging, sheltering, foraging, mating/breeding, nesting, and rearing young.[188] Various federally managed lands and state refuges along the path of the project also provide important habitat for birds throughout the project area.[189] The project would affect avian resources as a result of habitat degradation and loss; increased stress, injury, and mortality; disturbance and displacement; and loss of reproductive opportunity.

109. As with terrestrial wildlife, birds would generally avoid the disturbance caused by construction activities. Individuals avoiding these activities would be displaced to adjacent habitat, which could strain resources and resident wildlife. Impacts from operational activities could include injury and mortality from vegetation clearing for pipeline maintenance and inspections; stormwater discharge from the Mainline Pipeline aboveground facilities and the LNG Facilities; flare operation; human activity; and right-of-way maintenance. Finally, impacts on birds would include injury or mortality from an increase in hunting access and/or predation and spills.

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[186] *Id*.

[187] *Id*. at 4-321.

[188] *Id*.

[189] Description and maps of these areas are provided in the final EIS at sections 4.6.1 and 4.9.2.

110. Mitigation measures to avoid or minimize impacts on birds and their habitats are addressed in the *Migratory Bird Conservation Plan*, which sets forth the procedures to be implemented during project construction, operation, and maintenance for avian protection, and through implementation of project-specific plans such as the *Project Plan*, *Project Procedures*, *Winter and Permafrost Construction Plan*, *Lighting Plan*, and *Spill Prevention Plan*.

111. In addition, to the extent practicable, AGDC would conduct land disturbing activities on the Beaufort Coastal Plain during winter. Project-wide, AGDC would generally conduct vegetation clearing, grubbing, and other disruptive activities outside of timing windows recommended by the FWS for nesting birds, but some activities could overlap with nesting seasons.

112. Marine mammals, which are protected under the Marine Mammal Protection Act, may be affected by project construction and operation in the Beaufort Sea and Cook Inlet.[190] Vessel traffic through the Gulf of Alaska, Bering Sea, and the Chukchi Sea could also affect marine mammals. Potential impacts include vessel strikes, noise, and changes to foraging, mating, and migration behaviors.[191]

113. Underwater noise from pile driving, excavation, dredging, screeding,[192] anchor handling, and vessel operations can affect marine mammals' ability to communicate, navigate, avoid predators, mate, and locate food. Underwater noise can also cause habitat degradation, displacement, strandings, and changes in migration patterns. Airborne noise from pile driving, equipment and vessel operations, excavation, and aircraft overflights, could also result in behavioral impacts on marine mammals.[193]

114. To reduce impacts on marine mammals, AGDC would use Protected Species Observers during construction to identify any marine mammals that could come into proximity of project activities. Protected Species Observers would be used to monitor

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[190] This discussion addresses only marine mammals that are not federally listed as threatened, endangered, or other special status species as defined in the Endangered Species Act.

[191] Final EIS at 4-377. Table 4.6.3-2 lists the construction and operational activities with the potential to affect non-Endangered Species Act listed marine mammals and identifies which species could be present during those activities based on habitat, range, and timing of the activity.

[192] Subsea scraping (screeding) levels, pushes, or moves sediments on the sea floor to create a flat surface.

[193] Final EIS at 4-381 – 4-386.

marine mammals during anchor handling procedures and construction activities and minimize exposures of marine mammals to sound levels in excess of NMFS injury thresholds (Level A harassment). Protected Species Observers would have the authority to stop activities immediately, and/or lower noise levels when marine mammals are visible within the shutdown or harassment zones.[194]

115. AGDC committed to having at least two Protected Species Observers on watch during pile driving and at least one Protected Species Observer on watch during pipe laying in Cook Inlet but did not provide information regarding the number of Protected Species Observers for activities in Prudhoe Bay. AGDC also only committed to using land-based Protected Species Observers. Given the area required to be monitored and the lack of information on Protected Species Observers for Prudhoe Bay, the EIS recommends, and Environmental Condition 26 requires, AGDC to file a revised Protected Species Observer deployment plan that includes information on the number of Protected Species Observers for pile driving, anchor handling, and dredging and screeding activities.

116. Using the NMFS Technical Guidance to determine distances to Level A harassment (injury) and Level B harassment (disturbance), AGDC also proposed shutdown and harassment zones for pile driving in Cook Inlet and Prudhoe Bay and anchor handling activities to reduce impacts on marine mammals.[195] AGDC proposed shutdown, harassment, and mitigation zones for pile driving, but the zones did not apply to all activities, and would not match the modeled distances set forth in Appendix L-1, Wildlife and Fish Noise Calculated Results and Estimated Number of Vessel Trips. Further, the zone distances could change based on Marine Mammal Protection Act authorization, which provides NMFS or the FWS authority to authorize the incidental take of small numbers of marine mammals, subject to certain findings and procedures.[196] Accordingly, the EIS recommends, and Environmental Condition 25 requires, AGDC to revise the shutdown distances for all underwater noise-generating activities based on modeled distances or, alternatively, conduct a Sound Source Verification during construction to establish the appropriate shutdown or harassment zones.

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[194] *Id*. at 4-388.

[195] *Id*.

[196] AGDC has applied to NMFS and FWS for appropriate incidental take authorizations under the Marine Mammal Protection Act for construction activities in Cook Inlet and Prudhoe Bay.

117. To reduce impacts on marine mammals resulting from pipeline trench open cuts of shore approaches, AGDC would incorporate the use of the directional micro-tunneling continuation methodology for the shoreline crossings at Beluga Landing South and Suneva Lake, or provide a site-specific justification demonstrating that the methodology would not be feasible.[197] If used, the directional micro-tunneling continuation methodology would eliminate the risk of Level A harassment (injury) impacts on marine mammals from trenching and reduce the distance for Level B harassment (disturbance) impacts on marine mammals in Cook Inlet from up to 1.9 miles to 183 feet.[198]

118. To minimize vessel traffic impacts, AGDC would implement a *Transit Management Plan*, which identifies measures, such as reduced vessel speeds, to reduce traffic and collision. In its vessel contracts, AGDC would require vessels to comply with NMFS' *Vessel Strike Avoidance Measures & Reporting for Mariners*, which recommends, among other provisions, reducing speeds and maintaining separation between vessels and marine mammals, when present.[199] Vessels in transit through the Aleutian Islands would maintain compliance with the International Maritime Organization's Aleutian "Areas to be Avoided."[200]

119. During operation, the increase in vessel traffic would result in an increased risk of spills in marine habitats. To minimize the risk of a spill, AGDC would ensure that all contractors comply with the *Project Emergency Response Vessel Assurance Execution Plan*, and the *Spill Prevention Plan*, and/or *Stormwater Prevention Plan*, as applicable.

120. Vessel operations could introduce aquatic invasive species from ballast water discharge, fouled hulls, and equipment placed overboard. To avoid or minimize impacts, vessels would be required to adhere to federal regulations regarding Ballast Water Management, and AGDC's *Ballast Water Management Plan* that includes measures to minimize the risk of introducing aquatic invasive species.[201] Most impacts would be addressed through implementation of project-specific plans and through

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[197] Final EIS at 4-382.

[198] *Id*.

[199] *Id*. at 4-395.

[200] *Id*.

[201] *Id*. at 4-397.

compliance with federal regulations regarding vessel transit and ballast water discharges.

121. With implementation of the measures described above, AGDC's commitments, and the Environmental Conditions required in this order, the Alaska LNG Project would not result in significant effects on non- Endangered Species Act-listed marine mammals.[202]

7. Aquatic Resources

122. Alaska has a variety of freshwater and marine fish in its interior rivers and streams and coastal waters. Many of these fish are commercially important, such as salmon, walleye pollock, Pacific halibut, cod, and Pacific herring. The Alaska Department of Fish and Game manages freshwater, commercial, and subsistence fisheries as well as marine recreational fishing in Alaska. The Alaska Department of Fish and Game maintains data on anadromous waters and publishes the *Catalog of Waters Important for the Spawning, Rearing, or Migration of Anadromous Fishes,* also known as the Anadromous Waters Catalog, and an associated Atlas.[203] The Anadromous Waters Catalog is not a comprehensive list of all anadromous fish waterbodies in Alaska, but rather a list of waterbodies that have been surveyed by the Alaska Department of Fish and Game or private parties. Most of Alaska has not been surveyed. Once Anadromous Waters Catalog waters are identified, they are protected by Alaska state law, and AGDC would be required to apply for a Fish Habitat Permit to cross Anadromous Waters Catalog waters as well as any fish-bearing streams.[204]

123. Based on current data, 71 Anadromous Waters Catalog waters would be crossed by the Mainline Pipeline, 30 Anadromous Waters Catalog waters would be crossed by Mainline and Prudhoe Bay Treatment Plant access roads, and 14 Anadromous Waters Catalog waters would be crossed by the Point Thomson Unit Gas Transmission Line. Alaska Department of Fish and Game regularly updates its list of Anadromous Waters Catalog waters.[205] Therefore, to ensure that the appropriate mitigation and conservation

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[202] Additionally, as noted above, AGDC has applied to NMFS and FWS for appropriate incidental take authorizations under the Marine Mammal Protection Act; NMFS may require additional mitigation or alterations to mitigation measures identified in this analysis.

[203] Final EIS at 4-397.

[204] *Id*.

[205] The waterbodies that would be crossed by the Project, including those designated as Alaska Waters Catalog, are listed in Appendix I of the final EIS and

measures are implemented, the EIS recommends, and Environmental Condition 27 requires, AGDC to file a list of Anadromous Waters Catalog waters affected by project facilities prior to construction using the most current Alaska Department of Fish and Game Anadromous Waters Catalog list and NMFS's Essential Fish Habitat (EFH) species list, and the conservation measures it will apply at the appropriate waterbodies.[206]

124. Project construction and operation would result in temporary and permanent impacts on freshwater and marine fisheries and their habitat. Activities resulting in turbidity and sedimentation, alteration or removal of cover, blasting, introduction of pollutants, introduction of aquatic nuisance and nonindigenous fish species, permafrost degradation, water depletions, or entrainment of impingement, could increase rates of stress, injury, or mortality of fish. However, most impacts would be minimized through implementation of AGDC's project-specific plans, including the *Project Plan* and *Project Procedures*, *Revegetation Plan*, *Site-Specific Waterbody Crossing Plans*, *Water Use Plan*, *Invasives Plan, Spill Prevention Plan*, *Ballast Water Management Plan*, *Fisheries Conservation Plan*, and *Directional Micro-tunneling Plans*.[207] Specific mitigation measures would include installing erosion and sediment controls; using dry crossing, buried trenchless, or aerial installation methods at certain waterbodies; crossing waterbodies in dry or frozen conditions; and stabilizing and restoring stream beds and banks.[208]

125. In-stream trench blasting could occur in 337 waterbodies, of which 139 have known occupied fish habitat and 58 of which are listed as Anadromous Waters Catalog waters.[209] Blasting in waterbodies for material extraction or trench excavation could cause turbidity and downstream sedimentation and potentially harm fish directly in the blast zone. To minimize impacts, AGDC would develop site-specific measures in consultation with the Alaska Department of Fish and Game and implement the Alaska Blasting Standard for

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discussed in section 4.7.1.2.

[206] 16 U.S.C. § 1855(b)(4)(B) (2018); 50 C.F.R. § 600.920(k)(1) (2019). The Magnuson-Stevens Fishery Conservation and Management Act defines EFH as "those waters and substrates necessary to fish for spawning, breeding, feeding, or growth to maturity".

[207] Final EIS at 4-417 through 4-418.

[208] *Id*. at 4-417 through 430.

[209] *Id*. Appendix I lists those fish-bearing waterbodies where blasting could occur in-stream. Material site blasting would occur in or within 600 feet of 12 waterbodies listed as Alaska Waters Catalog.

trench or material site blasting near and within anadromous water bodies.[210] AGDC would file an updated *Project Blasting Plan* that includes monitoring of stream flow between blasting and in-stream construction measures as well as contingency measures to remediate loss of stream flow due to blasting, should this occur.[211]

126. Some access roads built across waterbodies would require the installation of culverts to maintain flow and provide fish passage. Long-term impacts on fish, particularly salmon, could occur if poorly designed or maintained culverts restrict the movement of migrating adults or fry.[212] To minimize impacts, NMFS recommended that AGDC follow the guidelines in *Anadromous Salmonid Passage Facility Design* for culverts. AGDC would provide, as part of the *Fisheries Conservation Plan*, a design and maintenance plan for culverts installed within fish bearing streams based on these guidelines.[213] AGDC has also committed to applying measures from the 2019 FWS *Alaska Fish Passage Program Fish Passage Design Guidelines* to the extent practicable.[214]

127. To minimize risks and impacts associated with spills, AGDC would require contractors and vessel operators to comply with the *Project Emergency Response Vessel Assurance Execution Plan*. Additionally, various types of vessels serving the project would be required to develop and implement *Shipboard Oil Pollution and Emergency Plans* and/or *Oil Discharge and Prevention Contingency Plans*, which include measures to be taken when an oil pollution incident has occurred, if possible.

128. Pursuant to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act), staff consulted with NMFS regarding impacts on EFH, and NMFS considered the draft EIS as initiation of consultation and provided conservation measures for impacts on EFH. Staff completed consultation with NMFS on September 23, 2019.[215] Based on staff's consultations with NMFS, and the

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[210] *Id*. at 4-443.

[211] *Id*.

[212] *Id*. at 4-420.

[213] *Id*.

[214] *Id*.

[215] *Id*. at Appendix M.

implementation of the various mitigation measures and recommendations, the EFH Assessment found that the project will result in minor impacts on EFH. [216]

129. With implementation of the measures described above, AGDC's commitments, and staff's recommendations, the final EIS concludes that the project will not result in significant adverse effects on fisheries.[217]

130. Project activities would result in temporary to permanent impacts on marine benthic invertebrates and their habitats. Project activities would result in habitat disturbance, increased noise, shading, sedimentation, turbidity, and temporary water quality changes resulting in stress, changes in the composition or abundance of species, and mortality of some individuals. However, most impacts would be minor given that a relatively small portion of the benthic populations in Cook Inlet and Prudhoe Bay would be affected.[218] Moreover, since most of the known invertebrate species in the project areas are common to the region and habitat disturbance would largely be limited to the construction phase, effects would likely be localized and only occur during construction.[219]

131. Vessel operations, particularly of LNG carriers, could affect benthic organisms though ballast water discharges, introduction of invasive species or spills of fuel and other hazardous materials. Based on LNG carrier design, a significant difference in temperature and salinity between ballast and ambient water are not anticipated.[220] Additionally, as discussed above, LNG carriers and marine barges used for this project would meet federal and state regulations for ballast water discharge and the project *Ballast Water Management Plan*. Since vessels would adhere to federal and state ballast water exchange regulations, aquatic invasive species would be expected to have little to no effect on benthic organisms; therefore, the effects of ballast water discharge in Cook Inlet on benthic invertebrates would be negligible.[221]

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[216] *Id*. at 4-478.

[217] *Id.*

[218] *Id*.

[219] *Id*. at 4-457.

[220] *Id*. at 4-459.

[221] *Id*.

132. With implementation of the measures described above and AGDC's commitments, the final EIS finds that the Alaska LNG Project would not result in significant adverse effects on marine benthic invertebrates.[222]

8. Threatened, Endangered, and Other Special Status Species

133. In consultation with FWS and NMFS, the final EIS identifies 32 species (or Distinct Population Segments[223] or Evolutionarily Significant Units of species) that are federally listed as threatened or endangered (or are identified as proposed, candidates, or under review for federal listing) and may occur in or near the project areas. Critical habitat has been designated in the project area for seven of these species. The final EIS also identifies 89 sensitive or watch list species with the potential to occur in the project area on BLM lands. Five of these species (Alaska-breeding Stellar's eider, spectacled eider, northern sea otter, polar bear, and wood bison) are federally listed.[224]

134. Impacts on federally listed species include construction activities in Prudhoe Bay and Cook Inlet that could disturb marine mammals and birds with noise, increased turbidity, effects on prey, and habitat disturbances and loss. In addition, activities associated with land-based construction, such as air traffic and lighting could affect federally listed species. Vessel traffic could also impact listed marine mammals and birds in the Beaufort Sea, Chukchi Sea, Bering Sea, Gulf of Alaska, and Cook Inlet, causing noise disturbances and potentially striking individuals. Some activities have the risk of a spills of fuel and other hazardous materials occurring on land or in-water that could affect federally-listed species.[225]

135. Pursuant to section 7 of the Endangered Species Act (ESA), the Commission, for actions involving major construction activities with the potential to affect listed species or critical habitats, is the lead federal agency and must submit its Biological Assessment

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[222] *Id*. at 4-478.

[223] Distinct Population Segments are defined as a portion of a species' or subspecies' population or range.

[224] The Eskimo curlew is federally listed and considered BLM-sensitive but is presumed extinct thus a detailed analysis of potential effects was not conducted. *See* Final EIS at 4-484.

[225] A detailed description of impacts and avoidance, minimization, and mitigation measures for construction and operation-related impacts on each federally listed or candidate species is included in the Biological Assessment, as well as a summary set forth in the Final EIS at Tables 4.8.1-3 and 4.8.1-4.

(BA) to the FWS and/or NMFS and, if it is determined that the action could adversely affect a federally listed species, the lead agency must submit a request for formal consultation to comply with Section 7 of the ESA. In response, the FWS and/or NMFS would issue a Biological Opinion as to whether the federal action would likely adversely affect or jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat.

136. The Alaska LNG BA along with requests to initiate formal consultation was provided to the FWS and NMFS on June 28, 2019.[226] Based on staff's analysis, the BA determined that the project would have no effect on two species, is not likely to adversely affect 23 species (Distinct Population Segments or Evolutionarily Significant Units), and is likely to adversely affect six species (spectacled eider, polar bear, bearded seal, Cook Inlet beluga whale, humpback whale, and ringed seal). The BA also determined that the project is not likely to adversely affect designated critical habitat for five species and is likely to adversely affect designated critical habitat for two species (polar bear and Cook Inlet beluga whale).[227]

137. Because formal consultation with section 7 is not complete, Environmental Condition 28 states that AGDC shall not begin construction until formal consultation is completed, it has received applicable incidental take authorization pursuant to the Marine Mammal Protection Act, as described above, and it has received written notification from the Commission that construction or use of mitigation may begin.[228]

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[226] Since that time, minor updates have been made to the Alaska LNG final EIS that are no longer reflected in the BA, as discussed in the Final EIS at Attachment O.

[227] A full discussion of staff's "likely to adversely affect" determinations are provided in the BA and briefly summarized in the Final EIS at Table 4.8.1-6.

[228] The Commission's practice of issuing conditional certificates has consistently been affirmed by courts as lawful. *Del. Riverkeeper Network v. FERC*, 857 F.3d 388, 399 (D.C. Cir. 2017) (upholding Commission's approval of a natural gas project conditioned on securing state certification under section 401 of the Clean Water Act); *see also Myersville*, 783 F.3d at 1320-21 (upholding the Commission's conditional approval of a natural gas facility construction project where the Commission conditioned its approval on the applicant securing a required federal CAA air quality permit from the state); *Pub. Utils. Comm'n. of State of Cal. v. FERC*, 900 F.2d 269, 282 (D.C. Cir. 1990) (holding the Commission had not violated NEPA by issuing a certificate conditioned upon the completion of the environmental analysis). In the event that formal consultation results in a finding of jeopardy, the consulting agency must suggest reasonable and prudent alternatives that avoid jeopardy. 16 U.S.C. § 1536(b)(3)(A) (2018). In that case, an applicant may be required to file with the Commission an

138. As discussed in the final EIS at section 4.6.3, the project would be covered under the FWS Biological Opinion for Issuance of 2016-2021 Beaufort Sea Incidental Take Regulations for construction activities in Prudhoe Bay that may affect Pacific walrus and polar bears under the Marine Mammal Protection Act.[229] In accordance with these regulations, AGDC would provide a *Polar Bear and Walrus Avoidance and Interaction Plan* and implement all applicable provisions regarding avoidance, minimization, and mitigation measures for these species.

139. Measures discussed above for marine mammals, such as use of Protected Species Observers in shutdown and harassment zones, would also reduce the risk of disturbance to listed marine mammals from underwater noise. To minimize the potential for vessel strikes, AGDC would require vessels to comply with NMFS guidelines and other measures regarding strike avoidance and reporting. As discussed above, AGDC would develop a Project *Transit Management Plan* for all vessels and a *Vessel Strike Avoidance Measures & Reporting for Mariners* for LNG carriers. Other measures would be implemented, such as slowing vessel speeds and implementing timing restrictions for pile driving. AGDC has also committed to conducting surveys for ringed seal lairs and polar bear dens prior to construction in suitable habitat.[230]

140. Nearly the entire population of Cook Inlet beluga whales is present on the western side of Cook Inlet near the project area each year in June and July for feeding and reproduction. AGDC would not conduct pile driving activities for Mainline Material Offloading Facility construction during these months to minimize impacts on Cook Inlet beluga whales. However, Mainline Pipeline pipelay could occur during these months, potentially resulting in noise impacts that exceed injury or behavior disturbance thresholds for beluga whales. As discussed above, AGDC would deploy Protected Species Observers and implement harassment and shut down zones for pile driving and anchor handling.

141. The final EIS identifies over 375 Species of Greatest Conservation Need, 26 of which are considered high priority species , including birds and marine mammals, with the potential to occur in the project area.[231] Eight of these species are federally listed under the ESA, and six of the species are protected under the Marine Mammal Protection Act, and will be subject to the avoidance, minimization, and mitigation measures set

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application to amend its project in order to avoid jeopardy and receive authorization to commence construction.

[229] Final EIS at 4-480. *See also* section 4.6.3.

[230] *Id*. at 4-506.

[231] *Id*. at 4-479.

under the ESA and Marine Mammal Protection Act. The final EIS concludes that project construction and operation would not be expected to result in significant effects on Species of Greatest Conservation Need.

142. Impacts and avoidance, minimization, and mitigation measures for BLM sensitive and watch list species would be similar to those for vegetation, territorial wildlife, birds, fisheries, and federally listed species, as discussed above. Permanent loss of suitable habitat would be limited, with significant amounts of similar habitats available in adjacent areas. Therefore, the final EIS concludes that impacts on BLM sensitive and watch list species would not be significant.

9. <u>Land Use, Recreation, and Special Use Areas</u>

143. Six land use/land cover types were identified in the project area and described in the final EIS: agricultural land; commercial/industrial land; forested land; open land; open water; and residential land.[232] Excluding offshore areas in Cook Inlet, the construction and operational footprints are predominantly open land (49 percent of construction and 53 percent of operation) and forested land (40 percent of construction and 39 percent of operation footprint).[233]

144. The project would have fewer impacts on agricultural, industrial, commercial, and residential lands. A majority of the land, excluding open water, that would be affected by construction is owned or managed by federal and state governments (19 percent and 69 percent, respectively). The remainder is owned by cites/boroughs (4 percent), Alaska Native corporations or other Alaska Native entities (4 percent), and private landowners (5 percent). A majority of the land (excluding open water) that would be affected by project operation is owned or managed by the federal and state government (19 and 63 percent, respectively), with the remainder owned by cites/boroughs (5 percent), Alaska Native corporations or other Alaska Native entities (3 percent), and private landowners (10 percent).

145. The Mainline Pipeline would cross or pass near industrial or commercial lands at Coldfoot, McKinley Village, and Byers Lake Campground in Denali State Park, as well as a parcel used by a river tour operator near MP 560. Construction would affect visitors to McKinley Village, campground visitors, and the river tour operator. Visitors to McKinley Village would experience increased noise and traffic, reduced access to businesses during construction, and traffic delays. To minimize these impacts, AGDC

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[232] *Id*. at 4-525.

[233] *Id*. at 4-527.

would schedule pipelay outside the peak tourist season and implement its *Traffic Mitigation Plan* for work during the tourist season.

146. Development of material extraction sites would block access to and permanently remove a portion of the Byers Lake Campground. The ADNR Division of Parks and Outdoor Recreation commented that the proposed material site near Beyer's Lake Campground would not be compatible with its mission and the park's management zones, and therefore it would not likely approve the material site. Should the material site be approved, AGDC would file a detailed schedule of construction activities. AGDC would also develop a site-specific construction schedule for activities to minimize disruption to the river tour operation. If it is not approved, then AGDC could utilize an alternative source.

147. Several comments were received regarding potential impacts on a family fishing operation where construction of the Mainline Pipeline could disrupt fishing access along the south shore of Cook Inlet on Boulder Point. AGDC would incorporate the use of the directional micro-tunneling continuation methodology for the shoreline crossing at Suneva Lake if geotechnical investigations confirm the feasibility of this method, as discussed above. If directional micro-tunneling continuation is implemented, it would avoid impacts on the fishing operation; otherwise, measures in the *Project Recreation and Commercial Fishing Construction and Mitigation Plan* would minimize impacts.

148. The final EIS identifies 127 residential buildings within 200 feet of the Mainline Facilities footprint. Construction impacts on these and any other residents near the pipeline would be temporary and minor. AGDC would implement site-specific mitigation measures to reduce impacts on residences, in addition to the standard BMPs identified in the *Project Plan*. AGDC would also conduct field surveys to confirm the locations and occupational status (i.e., seasonal or permanent; occupied or vacant) of residences.

149. Construction of the Liquefaction Facilities would result in the permanent conversion of residential land to industrial/commercial land, including the removal of ten residences from within the footprint of the LNG Facilities. AGDC would purchase these residences prior to construction. No other residences are within 200 feet of the Liquefaction Facilities, and there are no residences in the immediate vicinity of the Prudhoe Bay Treatment Plant.

150. The project would cross or pass near recreational areas on public lands, including: the Arctic National Wildlife Refuge (ANWR), Denali National Park, George Parks Highway National Scenic Byway, Iditarod National Historic Trail, and Dalton Highway Utility Corridor on federal lands; and Denali State Park, Nehana River Gorge, and North Slope Special Use Areas, Tanana Basin Planning Area, Tanana Valley State Forest, and various Game Management Units and refuges on state lands.

151. Most impacts on recreation areas and special interest areas would be temporary and minor. AGDC would minimize or mitigate impacts through implementation of construction and restoration best management practices, and would provide alternate access to affected sites, use flaggers or pilot cars to direct traffic, schedule activities outside peak tourist seasons, and comply with applicable crossing permits. The primary impact of project operation on recreation areas would be long-term to permanent changes in views due to maintenance of the pipeline right-of-way or installation of above ground facilities. Visual impacts during operation could be low to high, depending on the location and sensitivity of affected viewers.

152. Comments were filed regarding potential impacts on access to North Beach at Cook Inlet due to construction of the Liquefaction Facilities. Prior to construction, AGDC would develop plans to construct an alternate public beach access point, in consultation with the ADNR, Kenai Peninsula Borough, and private landowners.

153. The State of Alaska commented that the module staging pad for the Prudhoe Bay Treatment Plant would eliminate a state-run tundra monitoring station, which provides data on whether the tundra can be opened or closed for ice road construction and use. The ADNR would issue the lease for the staging pad, including provisions, if any, related to avoidance, relocation, or replacement of the monitoring station.

154. The Energy Policy Act of 2005 requires FERC to coordinate and consult with the Department of Defense (DOD) on the siting, construction, expansion, and operation of LNG terminals that would affect the military.[234] On March 1, 2017, the Commission received a letter from the DOD stating that results of an informal review indicated that the project may potentially affect military operations conducted in the project area. Specifically, the installation of Long Range Discrimination Radar at Clear Air Force Station (AFS) could result in the development of Special Use Airspace necessary for radar operation that would overlap or occur within about 0.25 mile of the Mainline Facilities, including a Mainline Valve and associated helipad. At Clear AFS's request, AGDC will coordinate with personnel to minimize impacts on Clear AFS during construction and operation and relocate the Mainline Valve and helipad. To ensure these facilities would be appropriately located, Environmental Condition 29 requires AGDC to develop a relocation plan in coordination with Clear AFS representatives.[235]

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[234] Pub. L. 109-58, 119 Stat. 594.

[235] Clear AFS and the Federal Aviation Administration are preparing an EIS to inform a decision on the design of additional Special Use Airspace necessary for the operation of Long Range Discrimination Radar. One tier of the proposed airspace would restrict flight activity from 400 feet up to 1,000 feet above ground level, within 0.25 mile of the construction footprint for the Mainline Facilities near MP 493.5. A second tier

155. We also consulted with DOD regarding the potential for impacts on U.S. Air Force radar operations in the Anchorage vicinity during project operation due to tall structures at the Liquefaction Facilities. The DOD indicated it had conducted a review based on a hypothetical structure height of 420 feet above ground level (513 feet above mean sea level) at its highest point. Based on that review, the DOD provided a letter on March 10, 2020, stating that DOD determined that the project would not adversely affect DOD missions within the Anchorage area.[236]

156. AGDC identified known sites within or near the project area where contaminated media could be disturbed. To reduce impacts at or from these sites, AGDC would, among other things, consult with agencies and landowners to identify the contaminants, adhere to applicable land use and institutional controls, restore drainage patterns to minimize erosion, install ditch plugs, and implement a *Groundwater Monitoring Plan* in areas where dewatering would occur near contaminated sites. Additionally, the Project *Unanticipated Contamination Discovery Plan* identifies measures to be implemented if construction disturbs previously unidentified contaminants in soil or groundwater.

157. With implementation of the measures described above, AGDC's commitments, and the Environmental Recommendations, the final EIS concludes that most impacts on land use, recreation, special interest areas, and hazardous waste sites would be minor.

10. <u>Visual Resources</u>

158. AGDC identified 91 key observation points where project facilities could be visible from visually sensitive resources or landscapes. Of these, AGDC has prepared pre-and post-construction simulations for 33 key observation points. AGDC determined that visual simulations of the other key observation points were not necessary based on the anticipated scope of the visual impacts, the expected extent of the visibility of the project, and/or the availability of other key observation points with more representative views in the area.

159. Construction would have high impacts on 11 key observation points evaluated and project operations would have high impacts on 9 key observation points. AGDC would implement mitigation measures including minimizing vegetation clearing, adhering to the *Project Lighting Plan*, and using fencing to screen workspaces.

160. The NPS filed comments regarding visual impacts in the Denali National Park. Generally, construction and operation would have low to moderate impacts on key

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would overlay the project footprint from about MPs 486 to 498 and would restrict flight activity from 1,000 feet up to 33,000 feet above ground level. *See* final EIS at 4-716.

[236] eLibrary Accession number 20200310-3022.

observation points in the Denali National Park, due in part to the project's position in the landscape; the Mainline Pipeline right-of-way would be parallel to and near the Parks Highway where topography, screening vegetation, and the highway would limit the contrast generated by the project. The one high impact, which would occur at the trail leading to the Nenana River pedestrian bridge north of the Denali National Park entrance, would potentially be significant, although the site has low scenic inventory value and the impact rating would drop to moderate following construction. Construction during the summer months could produce particulate matter and dust visible to Denali National Park visitors, but impacts would be minimized through implementation of the *Project Fugitive Dust Control Plan*.

161. BLM filed comments requesting that AGDC not introduce new vegetation that contrasts with existing conditions in areas where minimal or no vegetation currently exists. BLM also requested that mitigation measures should seek to blend in with the surrounding landscape and that all permanent structures be painted a camouflaging color. AGDC will address these BLM provisions during the permitting and right-of-way process with the BLM.

162. Impacts on visual resources at project facilities due to artificial lighting would be reduced through implementation of the *Project Lighting Plan*. NPS commented that outdoor lighting at the Healy Compressor Station, which could be visible from portions of the Denali National Park, should follow International Dark-Sky Association Guidelines and have a color temperature of 3,000 Kelvins or less. AGDC would file a site-specific lighting plan for the Healy Compressor Station conforming to these guidelines or provide justification for why it cannot.[237]

163. With implementation of the *Project Lighting Plan* and other measures described above,[238] the final EIS concludes that the project's effects on visual resources would not be significant.

11. <u>Socioeconomics</u>

164. The final EIS examines an area of interest for the project's potential socioeconomic impacts, including the North Slope Borough, Yukon-Koyukuk Census Area, Fairbanks North Star Borough, Denali Borough, Matanuska-Susitna Borough, Kenai Peninsula Borough, and Anchorage. Within those areas, cities or census-designated places within 10 miles of the Mainline Facilities or 50 miles of the Prudhoe Bay Treatment Plant or Liquefaction Facilities were included as potentially affected communities. The area of interest for the project is predominantly rural and sparsely

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[237] *Id*. at 4-617.

[238] See list of mitigation measures listed in Table 4.10.2-2.

populated except for the areas in and around Anchorage and Fairbanks. The total population of all communities in the area of interest was about 574,865 residents in 2017, representing nearly 77 percent of Alaska's population. Anchorage is the largest city in Alaska, with a population of 298,225 residents in 2017, which accounts for over half of the areas of interest population. Fairbanks, with a population of 31,853 residents in 2017, is the second largest city in Alaska. The population of the area of interest, minus Anchorage and Fairbanks, was 244,787 residents in 2017.[239] Project construction would increase the population in the area of interest due to worker influx, but this impact would generally only last the length of construction (8 years). During project operation, population increases due to direct project hires would be relatively small but indirect and induced population growth in the Kenai Peninsula, particularly in communities around the LNG facilities, could increase by an estimated 3.5 percent over 2017 levels.[240]

165. In addition to increased employment, construction would result in state-wide economic benefits from worker spending and purchases of materials, supplies and services. Several comments asked about cost-of-living increases, particularly in remote areas. While inflation is possible, impacts would be mitigated by use of closed construction camps and supply procurement from major centers rather than local sources.

166. Other commenters raised hiring practices for Alaska residents. Although a large percentage of the project workforce would be from out of state, Alaska Department of Labor and Workforce Development's *Alaska LNG Project Gasline Workforce Plan* released in April 2018 identifies anticipated workforce needs to construct and operate the project and provides recommendations for training programs throughout the state, policy recommendations, and suggestions to maximize "Alaskans First" hiring practices on the project.[241] The plan also includes goals to increase workforce diversity through outreach and training programs.[242]

167. Project construction could temporarily affect commercial fisheries, especially in Cook Inlet by impeding access to fishing areas, increasing vessel traffic, or damaging gear. Impacts would likely be minor, but to further reduce impacts, AGDC would develop a *Project Recreational and Commercial Fishing Construction and Mitigation Plan*, coordinate its activities with industry sources, and notify commercial fishing operations prior to starting construction. Additionally, AGDC would work with set-

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[239] Final EIS at 4-464. Alaska's population is projected to reach 746,582 in 2020.

[240] *Id*. at 4-627 through 4-628.

[241] *Id*. at 4-639.

[242] To the extent issues arise regarding hiring practices, this is a matter outside of the Commission's jurisdiction. *See NAACP v. FPC,* 425 U.S. 662 (1976).

netters and the Alaska Department of Fish and Game to estimate measurable loss of harvest and provide compensation.

168. The project would permanently affect taxes collected and revenue generated by state and local governments and likely result in an increase in government expenditures. During construction, state and local government revenues generated from taxes would increase due to materials purchases, payroll expenditures, and property and other taxes. The method used by the Department of Revenue to value the project as a whole and to divide the value to different communities along the project would affect property tax revenue received by individual local governments. Revenues from other location-specific special use taxes such as taxis, rental car, motor fuel, and utility taxes would also be expected to increase as construction workers and others move into the region. Project operation would result in the state receiving additional production taxes, royalties paid in kind, and other taxes, including business and corporate taxes.[243]

169. Alaska Native commenters raised concern that the increase in population could result in a temporary increase in antisocial behavior, including crimes against persons and property. AGDC's *Health Impact Assessment* noted that the presence of work camps and outside workers have the potential to exacerbate existing health and social problems.[244] During construction, work camps would be self-contained and AGDC would employ private security. Camp security staff would be responsible for tracking, sorting, and implementing daily transits to and from the camps during rotations, demobilizations, and mobilizations; and for securing the camp perimeter from unauthorized entry or exit.[245]

170. Since construction camps would use private security and have no direct impact on the population size of nearby communities, the direct impact on local police and fire services would be minor in communities with high levels of law enforcement, such as Anchorage.[246] However, in communities where construction workers may live outside of construction camps such as Kenai in which has limited public resources, community services may be adversely affected. Prior to initial site preparation, Environmental

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[243] *Id*. at 4-651. The State of Alaska requires at least 25 percent of all mineral lease rentals, royalties, royalty sale proceeds, and federal mineral revenue sharing payments and bonuses received by the State to be placed in the Alaska Permanent Fund (Alaska Permanent Fund Corporation, 2020). Therefore, a portion of royalties resulting from the project could benefit the Alaska Permanent Fund.

[244] Id. at 4-665. *See* Appendix V, *Health Impact Assessment*.

[245] *Id*. at 4-665.

[246] *Id*.

Condition 48 requires AGDC to file a *Cost-Sharing Plan* identifying the mechanisms for funding all project-specific security/emergency management costs that would be incurred by state and local agencies, including funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base, which could be satisfied with overall Payment in Lieu of taxes payments. This would alleviate possible public resource shortages proximal to the Liquefaction Facilities.

171. Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, requires specified federal agencies to consider if impacts on human health or the environment (including social and economic aspects) would be disproportionately high and adverse for minority and low-income populations and appreciably exceed impacts on the general population or other comparison group.[247] The Commission is not one of the specified agencies and the provisions of Executive Order 12898 are not binding on this Commission. Nonetheless, in accordance with our usual practice, the final EIS addresses this issue.[248]

172. A minority population exists when a community's population is over 50 percent minority or if its minority population is meaningfully greater than the percentage in the general population or other comparison group. The State of Alaska (33 percent minority) was used as the comparison group. For the purposes of this analysis, "meaningfully greater" is assumed to be equal to or greater than 1.2 times the State of Alaska minority population, which equates to a minority population of 40 percent or higher.[249] A low-income population exists when a community's population is over 50 percent low-income or when the low-income population percentage of the community exceeds that of the general population or other comparison group which, for the purposes of this analysis, is the State of Alaska. In the State of Alaska, 10.1 percent of the population is at or below the poverty level.[250] Based on these criteria, the final EIS identified 15 U.S. Census block groups that are crossed by the project and are environmental justice communities.[251]

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[247] Executive Order No. 12898 (Feb. 11, 1994), reprinted at 59 Fed. Reg. 7629 (Feb. 16,1994).

[248] Final EIS at 4-664 through 4-674.

[249] *Id*. at 4-676.

[250] *Id*.

[251] *Id*. at 4-678. Census tracts and block groups are identified at 4.11.8-3.

173. Executive Order 12898 also calls for consideration of populations that rely on subsistence consumption of fish and wildlife for a principal portion of their diet. Where an agency action may affect fish, vegetation, or wildlife, subsistence patterns of consumption, the analysis should address the potential for disproportionately high and adverse impacts on minority and low-income populations. Subsistence activities were found to occur within 29 communities in the area of interest; of these communities, six U.S. Census block groups also qualify as environmental justice populations.[252]

174. The final EIS states that project construction and operational impacts that could have the potential to disproportionately affect environmental justice populations include traffic delays and new traffic patterns, visual effects from nighttime lighting or changes to the existing viewshed; interference with subsistence activities or habitats; potential changes to residential property values; and health impacts.[253] As discussed herein, however, the final EIS concludes that project-related traffic would be temporary and not result in significant impacts and that the project would not have a significant effect on visual resources. Likewise, while the long-term and permanent effects of the project could disproportionately affect some environmental justice communities by altering caribou migration patterns and providing additional access in undeveloped areas to non-local hunters, these impacts are not expected to be high and adverse.[254] Similarly, the final EIS finds that residential property values would not be expected to be negatively affected by the project facilities.[255]

175. Finally, based on AGDC's *Health Impact Assessment*, and staff's environmental justice analysis, staff determined that while the impacts from construction on infectious diseases would be temporarily high and adverse, these impacts would not disproportionately affect environmental justice populations. During construction, nearly all construction workers would be housed in closed worker camps and transported to and from the right-of-way. This would reduce many of the potential negative impacts associated with interaction with rural, isolated populations. Even so, the *Health Impact Assessment* concludes that construction would have a medium adverse effect on the social determinates of health, which could disproportionately affect environmental justice populations due to anxiety and depression associated with potential impacts on subsistence. Permanent health impacts would be unlikely to have disproportionately high and adverse impacts on environmental justice populations. Nevertheless, we expect that

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[252] *Id*. at 4- 678 through 4-679. Census tracts and block groups are identified at Table 4.11.8-1.

[253] *Id.* at 4-679.

[254] *Id*. at 4-683.

[255] *Id.*

AGDC would work closely with local and federal health authorities to ensure that public health is adequately protected. Therefore, although the project has the potential to disproportionately impact environmental justice communities, the final EIS concludes that the impact would not be high or adverse.

176. The final EIS concludes that with the implementation of the measures described above, AGDC's commitments, and staff's recommendations, adverse impacts on socioeconomic conditions due to project construction and operation would not be significant. Positive impacts on state and local economies in most areas would be temporary but high during construction, and minor during operation.[256]

12. <u>Transportation</u>

177. The project would affect vehicular, rail, marine, and air traffic due to the movement of construction materials, personnel, and supplies. Construction impacts would include increased traffic volumes and increases in congestion and traffic delays, along with corresponding increases in traffic safety risks. Impacts during construction are expected across, or adjacent to, roads and rail lines. Operational impacts would be primarily related to LNG carrier activities at the Liquefaction Facilities.

178. Construction of the Mainline Facilities would require the use of 649 access roads to link work areas to the major highways. Of that total, 132 existing roads would be used as-is, 28 existing roads would require upgrades such as widening or addition of gravel, and 489 new access roads would be built. The Liquefaction Facilities would be accessed directly from the Kenai Spur Highway.[257]

179. To minimize impacts on public roads and highways, AGDC would, prior to issuance of a state Right-of-Way Grant for lands associated with the project, enter into a Highway Use Agreement with the Alaska Department of Transportation and Public Facilities (Alaska DOT).[258] AGDC's *Traffic Mitigation Plan* sets forth measures to reduce impacts from construction traffic, lane closures, and open-cut crossings. This plan would

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[256] *Id*.

[257] Construction of the proposed Liquefaction Facilities would require relocating about 1.3 miles of the existing Kenai Spur Highway, which connects the Sterling Highway (Alaska Highway 1) to a port facility at the north end of Nikishka Beach Road. EIS at 4-1163.

[258] *Id*. at 4-705.

be reviewed and approved by the Alaska DOT prior to the issuance of road construction permits.

180. AGDC would use the Alaska Railroad and rail spurs to transport fuel, pipe, equipment and other materials to the project area. Rail car demand would exceed available capacity, but AGDC would implement long-lead contracting to allow the Alaska Railroad to procure additional cars.[259] Congestion along the rail line could occur during the summer season when passenger trains for tourists are present. To avoid impacts on passenger and tourist rail use, AGDC would implement mitigation measures, including conducting some freight movements at night.[260]

181. Most of the equipment and material used for project construction would be shipped to Alaska on oceangoing vessels. No single port has the current capacity to receive the volume of cargo required for project construction; AGDC would use multiple existing ports and construct a Marine Terminal Offloading Facility at Nikiski and a Mainline Material Offloading Facility near the existing Beluga Landing.[261]

182. Equipment deliveries during construction would increase vessel traffic in navigation channels, resulting in temporary but minor to moderate impacts on other vessels. Construction in Cook Inlet would also affect navigation, but AGDC would coordinate its activities with the Coast Guard, commercial vessels, and other users to reduce impacts.[262] The Coast Guard has reviewed the project pursuant to its *Navigation and Vessel Inspection Circular 01-2011* and determined that Cook Inlet is suitable for accommodating project LNG carrier activity.[263]

183. Air transportation would be used for the movement of workers, supplies, and equipment destined for remote areas of Alaska because of the long distances between cities and the limited highway and railroad infrastructure. Most air travel would be associated with worker movements during scheduled rotation periods. The project would use Anchorage International, Fairbanks International, Kenai Municipal, and Deadhorse Airports as regional hub airports for the transportation of project personnel, resulting in moderate impacts during construction, including flight delays and higher demand for

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[259] *Id*. at 4-707.

[260] *Id*.

[261] *Id*.

[262] *Id*. at 4-714.

[263] *Id*. at 4-715.

flights.[264] The City of Kenai noted that increased security screening and/or airfield improvements may be needed to accommodate additional flights. AGDC would consult with Kenai Municipal Airport representatives to identify solutions to accommodate the additional volume.[265]

184. The final EIS concludes that with implementation of the measures set forth above, adverse impacts on transportation resources from project construction and operation would not be significant.[266]

13. <u>Cultural Resources</u>

185. Section 106 of the National Historic Preservation Act and its implementing regulations require agencies to undertake a "reasonable and good faith effort" to identify historic properties within a project's "area of potential effects" that may be affected by their undertakings, and afford the Advisory Council on Historic Preservation (ACHP) a reasonable opportunity to comment on the undertaking.[267]

186. Project construction and operation could potentially affect historic properties, such as cultural resources either listed or eligible for listing in the National Register of Historic Places. These historic properties could include prehistoric or historic archaeological sites, districts, buildings, structures, or objects, as well as locations with traditional value to federally recognized tribes, Alaska Native Claims Settlement Act village and regional corporations, or other groups.

187. AGDC conducted research, consulted with state and federal agencies, and performed field surveys, which are not yet completed, to identify archaeological and architectural resources in the construction footprint of the project. AGDC identified the archaeological area of potential effects for direct effects as the rights-of-way for construction of the: Point Thomson Unit Gas Transmission Line; Prudhoe Bay Unit Gas Transmission Line; Mainline Pipeline; footprint of off-corridor facilities, additional temporary work spaces, permanent and temporary access roads, and the Prudhoe Bay Treatment Plant and Liquefaction Facilities, including submerged lands in the Beaufort

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[264] *Id*.

[265] *Id*. at 4-717.

[266] *Id*. at 4-718,

[267] 54 U.S.C. § 306108 (Pub. L. No. 113-287, 128 Stat. 3227, Dec. 19, 2014); 36 C.F.R. pt. 800 (2019).

Sea and Cook Inlet.[268] AGDC identified an indirect area of potential effects as a one-mile buffer around all project components.[269]

188. Field surveys to date identified 52 sites that are listed or eligible for listing in the National Register of Historic Places, including various segments of roads and trails, the Rosebud Knob Archaeological District, and the Gallagher Flint Station National Historic Landmark.[270] The Alaska State Historic Preservation Office (SHPO) concurs with these eligibility determinations. AGDC submitted 22 reports to the Commission, the Alaska SHPO, the BLM, and/or the NPS that provided the results of the archaeological studies conducted between 2013 and 2019, including site evaluations on BLM lands, an assessment of submerged resources in Cook Inlet, and a survey of NPS lands.[271] AGDC would survey the remaining Mainline Pipeline route, including the portion of the route on NPS lands, and ancillary facilities for archaeological and aboveground historic architectural resources, and submit the results of these surveys to the appropriate agencies in future survey reports.

189. Commission staff consulted with Indian tribes and Alaska Native regional corporations that may attach religious or cultural significance to sites in the region or may be interested in potential impacts from the project on cultural resources. In response to notifications to 38 federally recognized tribes,[272] the Chickaloon Native Village, the Knik Tribe, and the Native Village of Tyonek responded. In a letter dated November 25, 2015, the Chickaloon Village Traditional Council expressed its interest in participating in the section 106 process. Because most of the Alaska Stand Alone Pipeline[273] routing is

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[268] *Id*. at 4-719.

[269] *Id*.

[270] *Id.* at 5-40.

[271] *Id*.

[272] *Id*. at 4-727. The 38 tribes are identified in Table 4.13.2-1.

[273] The Alaska Stand Alone Pipeline was intended by the Alaska State Legislature to address in-state gas needs as the primary project objective (Alaska Statute [AS] 31.25.005). Under the Alaska Stand Alone Pipeline Project, AGDC proposed to construct a 733-mile-long, 36-inch-wide natural gas pipeline from the North Slope to an existing natural gas distribution system (ENSTAR Natural Gas Company), which serves the south central region of the state. The Alaska Stand Alone Project does not involve the export of natural gas outside of Alaska and AGDC has stated that the project will not be required if the Alaska LNG Project proceeds. On March 4, 2019, the COE and BLM

similar to the alignment proposed for the project, the Chickaloon Village Traditional Council requested that staff review all available data regarding that route, to help inform its analysis of the AGDC project. This data was incorporated into the review of the project, as requested.[274]

190. Staff met with nine tribes, as well as the Cook Inlet Regions Inc., an Alaska Native regional corporation of which Cook Inlet tribes are shareholders. In addition to staff's contacts with the tribes, AGDC sent project introduction letters to 19 tribes to provide them an opportunity to identify any concerns related to properties of traditional religious or cultural significance that could be affected by the project.[275] Of the 19 tribes, only the Ninilchik Traditional Council and the Village of Salamatof did not request further consultation.

191. AGDC developed procedures to be used in the event that any unanticipated historic properties or human remains are encountered during construction and provided the *Project Plan for Unanticipated Discovery of Cultural Resources and Human Remains* to the Commission, the Alaska SHPO, and BLM. The plan includes procedures for notifying consulting and interested parties, including Alaska Native tribes, in the event of any discovery.[276]

192. As noted above, AGDC has not completed cultural resources surveys and/or National Register of Historic Places evaluations. Consistent with Under the Commission's responsibilities under the National Historic Preservation Act and its implementing regulations, on March 25, 2020, staff circulated for comment a draft Programmatic Agreement with the ACHP, Alaska SHPO, BLM, NPS, Indian tribes, and AGDC, to outline the process for identifying historic properties and measures that will be taken to resolve adverse effects on historic properties that cannot be avoided.[277] The EIS recommends, and Environmental Condition 30 requires that AGDC shall not start project construction until all outstanding archaeological and architectural surveys are complete;

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issued a joint Record of Decision for the Alaska Stand Alone Project. See Final *EIS* at 1-18.

[274] *Id*.

[275] *Id*. at 4-732.

[276] *Id*. at 4-732. To date, AGDC has not filed SHPO or BLM Comments on the plan.

[277] Should a required signatory terminate consultation, the Programmatic Agreement will not go into effect and compliance with section 106 will proceed pursuant to 36 C.F.R. pt. 800, Subpart B (2019).

survey and evaluation reports and treatment or avoidance plans, if required, have been prepared and reviewed by the appropriate agencies, the ACHP is provided an opportunity to comment if historic properties would be adversely affected, and the Commission provides written notice to proceed.

14. Subsistence

193. The customary and traditional use of wildlife resources has been important to Alaska Native communities for millennia. As described in the final EIS, Alaska Natives have a long relationship and connection with the land and water resources within their traditional territories. The land and all it provides are considered essential to Alaska Native economic and cultural identity and continuity. The traditional use of land and the resources it provides in support of life are commonly referred to as subsistence. The project's potential to affect subsistence resources and users has been a concern explicitly expressed by Alaska Natives, federal and state resource agencies, and many others in scoping meetings, government-to-government meetings, and letters to the Commission.

194. The final EIS evaluates potential impacts on subsistence resources and activities for 33 communities that live or harvest within 30 miles of the project.[278] The final EIS considers how changes in resource availability, cost and effort of harvest, access to and competition for resources, and harvest rates due to project construction and operation would or could affect the subsistence practices of each community.[279]

195. The final EIS finds that the project would have the potential for both adverse and beneficial effects on subsistence resources and users. Potential beneficial effects would include improved or new access routes to traditional harvest areas.[280] In some locations, vegetation conversion would create new forage for moose. Potential adverse effects on subsistence as discussed above would include reductions in subsistence resource abundance and availability, restrictions in access to traditional use areas, and increased competition for subsistence resources from rural and non-local harvesters. The nature of potential effects would vary by community and geographic region.[281]

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[278] Table 4.14.1-1 lists the subsistence regions and study communities; Table 4.14.1-2 lists subsistence study communities associated with the project.

[279] The evaluation was informed by the analyses of impacts on wildlife, fish, and vegetation, as discussed above, and addressed in detail in the final EIS at sections 4.5 through 4.8, and socioeconomic conditions as discussed in section 4.11.

[280] Final EIS at 4-749.

[281] *Id*. at 4-749 – 4-750.

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

197. While the final EIS concludes that project construction and operation would result in a variety of impacts on subsistence users, it notes that the magnitude, if not the duration, of the impact is difficult to define, primarily due to the complexity of predicting the numerous interactions between human behavior and physical resources, both of which would be affected.[282]

198. To reduce impacts on subsistence communities and uses, AGDC has committed to the following: coordinate with local communities, including tribal councils, to identify locations and times where subsistence activities could occur, and modify schedules to minimize work to the extent practicable, particularly work that could reduce resource availability or user access, such as blasting or trenching; employ community representatives to alert project representatives about planned subsistence activities or key places to avoid; station all project employees and temporary workers at construction camps, and prohibit hunting, fishing, and gathering activities by those workers; avoid and minimize impacts on subsistence whaling and marine mammal hunting by coordinating with individual whaling associations; require mandatory subsistence training for the project employees; and establish a Local Subsistence Implementation Committee comprising project personnel, local subsistence representatives, and appropriate agency personnel.[283]

199. Additionally, prior to construction, AGDC would file with the Commission, for the review and written approval, the *Project Local Subsistence Implementation Plan* and a signed Conflict Avoidance Agreement prepared in coordination with NMFS and the Alaskan Eskimo Whaling Commission.[284]

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[282] *Id*. at 4-750.

[283] *Id*.

[284] *Id*. at 4-751. In addition to the subsistence review in the in final EIS, BLM

200. Earthjustice asserts that it was inappropriate for the draft EIS to rely on potential mitigation measures to address subsistence impacts, claiming that the draft EIS only states AGDC has committed to implement the measures described which, Earthjustice claims, are not enforceable.[285] We disagree. Environmental Condition 1 requires AGDC to "follow the construction procedures and mitigation measures described in its application and supplement …and as identified in the EIS..." The mitigation commitments by AGDC are both part of the supplemental record for the project and are described in the final EIS, including Appendix X, which sets forth the mitigation measures recommended in the draft EIS to which AGDC has committed, including measures to mitigate subsistence impacts.

201. The final EIS concludes that, while the project would result in impacts on subsistence resources and activities, the impacts would not be significant with the implementation of the measures described above.

15. Air Quality and Greenhouse Gas Emissions

202. Emissions from vehicles and equipment, marine and air traffic, waste incinerators, open burning, and fugitive dust would affect air quality during project construction. AGDC would implement various measures to reduce construction emissions, including use of gasoline limited to 10-parts per million (ppm) sulfur, and onshore diesel limited to 15-ppm sulfur, use of electric generators in compliance with New Source Performance Standards (NSPS) Subpart III, and use of rock crushers equipped with wet dust suppression controls.[286] AGDC would also implement its *Open Burning Plan and Fugitive Dust Control Plan*, which would be used to manage open burning activities to ensure that emissions generated during open burning do not create a health hazard or public nuisance.[287] Additionally, AGDC would obtain air permits from ADEC for these equipment units/activities prior to installation. Both the waste incinerator and the

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prepared a subsistence analysis on behalf of the Department of Interior to fulfill the departmental requirements pursuant to section 810 of the Alaska National Interest Lands Conservation Act (ANILCA). Section 810(a) of the Alaska National Interest Lands Conservation Act, 16 United States Code (USC) 3120(a), requires that an evaluation of subsistence uses and needs be completed for any federal determination to "withdraw, reserve, lease, or otherwise permit the use, occupancy, or disposition of public lands." This analysis is attached as Appendix U to the final EIS.

[285] Earthjustice October 3, 2019 Comments at 22.

[286] *Id*. at 4-932.

[287] *Id*. at 4-668.

stationary generators at construction camps would also require Title V operating permits, which AGDC would obtain based on the timing specified within the construction permits to be issued by ADEC.[288]

203. A General Conformity applicability analysis is required for any part of a project occurring in nonattainment or maintenance areas for criteria pollutants. None of the direct project emissions would occur within a nonattainment or maintenance area.[289] The project would generate a small amount of indirect emissions within the Fairbanks particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$) Nonattainment Area, the Fairbanks Area carbon monoxide (CO) Maintenance Area, the Anchorage CO Maintenance Area, and the Eagle River particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) Maintenance Area from construction support and equipment transportation.[290] The maximum annual emissions generated by the project in these areas would not exceed General Conformity applicability thresholds, therefore, a General Conformity Analysis is not required.[291]

204. Based on AGDC's analysis of predicted air emissions, the final EIS concludes that construction of the Prudhoe Bay Treatment Plant, Point Thomson Unit Gas Transmission Line, Prudhoe Bay Unit Gas Transmission Line, and Mainline Facilities would have temporary, minor impacts on air quality. Construction of the Liquefaction Facilities would have temporary, moderate impacts on air quality, but would contribute to significant impacts during construction Years 7 and 8 when combined with operational emissions, as discussed below.[292]

205. Operation of the Prudhoe Bay Treatment Plant, Mainline compressor stations and heater station, and Liquefaction Facilities would result in emissions of criteria pollutants, GHG emissions, and hazardous air pollutants (HAP). Fugitive air emissions would also be generated by operation of the Point Thomson Unit Gas Transmission Line, Prudhoe Bay Unit Gas Transmission Line, and Mainline Facilities, but the resulting impacts on air quality would be minor and limited to the area near the pipeline systems.

206. The Prudhoe Bay Treatment Plant would not cause or contribute to an exceedance of the National Ambient Air Quality Standards (NAAQS)/Alaska Ambient Air Quality

[288] *Id*.

[289] *Id*. at 4-928.

[290] *Id*. at 4-929.

[291] *Id*.

[292] *Id*. at 4-974.

Standards (AAAQS) for any criteria pollutant or exceed Prevention of Significant Deterioration (PSD) incremental thresholds. Similarly, Prudhoe Bay Treatment Plant operation would not cause or contribute to an exceedance of the NAAQS/AAAQS or PSD increment thresholds at nearby Class II nationally designated protected areas (ANWR and Gates of the Arctic National Park and Preserve) but could contribute to visibility impacts at these sites due to haze or nitrogen deposition. Intermittent activities such as flaring could cause short-term impacts on regional haze and deposition. The full PSD impact analysis would be completed as part of the Alaska state PSD permitting process.

207. The annual emissions for each of the compressor stations and heater station along the Mainline Pipeline would be below PSD major source thresholds, though each station would be a Title V major source and a minor source under ADEC's Minor New Source Review (NSR) program. Operation of the compressor stations and heater station would not cause or contribute to an exceedance of the NAAQS/AAAQS for any criteria pollutant. An analysis of potential impacts on nearby Class I and II nationally designated protected areas found that the Federal Land Manager (FLM)-established visibility threshold and sulfur deposition threshold at the ANWR could be exceeded by emissions from the Galbraith Lake Compressor Station.[293] FLM-established nitrogen deposition thresholds at multiple Class I and II areas—including ANWR, Gates of the Arctic National Park and Preserve, Gates of the Arctic Preserve, Yukon Flats National Wildlife Refuge, Kanuti National Wildlife Refuge, Denali National Park, and Kenai National Wildlife Refuge—could also be exceeded by operation of the stations.

208. The Liquefaction Facilities would be a PSD major source for CO, nitrogen oxides (NO_X), volatile organic compounds (VOC), PM_{10}, $PM_{2.5}$, sulfur dioxide (SO_2), and GHGs; a Title V major source for CO, NO_X, VOC, PM_{10}, and $PM_{2.5}$; and a major source for HAPs. Under normal operating conditions, the Liquefaction Facilities would not cause or contribute to an exceedance of the NAAQS/AAAQS for any criteria pollutant or exceed PSD incremental thresholds. Additionally, the Liquefaction Facilities would not cause an exceedance of the NAAQS/AAAQS or PSD increments for nearby Class I or II nationally designated protected areas. Emissions would exceed the threshold for causing

[293] The Federal Land Managers' Air Quality Related Values Work Group (FLAG) document was developed by the US Department of Agriculture Forest Service, NPS, and FWS. The thresholds established in the FLAG document aren't specific to Alaska, but are screening thresholds that are used as a starting point when completing Air Quality Related Values (AQRV) analyses for Class I areas. If the modeled impacts are under the screening threshold, then it is considered that project would not result in an impact to AQRVs. If it's above the screening thresholds, then coordination with the FLM is used to evaluate the impact and determine if additional mitigation is needed.

visibility impairment in the Denali National Park and for contributing to visibility impairment in Tuxedni National Wildlife Refuge, Kenai Fjords National Park, and Lake Clark National Park and Preserve. Emissions could also exceed sulfur and/or nitrogen deposition thresholds at the Tuxedni National Wildlife Refuge, Kenai National Wildlife Refuge, Lake Clark National Park, and the Denali National Park. Activities such as flaring could cause short-term impacts on regional haze.[294] The full PSD impact analysis would be completed as part of the PSD permitting process.

209. Based on comments from the NPS and in response to staff's recommendation in the draft EIS, AGDC filed revised air dispersion modeling for the project facilities and all air emissions sources to identify and disclose impacts on units of the NPS or other federally protected areas.[295] Without mitigation, emissions from the Prudhoe Bay Treatment Plant and Liquefaction Facilities could have a significant impact on regional haze and acid deposition in some Class I and Class II nationally designated areas, including the Denali National Park. Additional mitigation measures could be implemented during the ADEC air permitting phase that would reduce these impacts.

210. Although AGDC has not provided a detailed construction and operation schedule, there is potential for portions of the Liquefaction Facilities to be placed in-service sequentially while construction is ongoing. Simultaneous construction, startup, and operational activities could occur in Years 7 and 8, which would result in overlapping emissions in excess of the modeled emissions for operation.[296] During these 2 years, emissions levels could exceed the NAAQS/AAAQS for PM_{10} and $PM_{2.5}$.[297] AGDC would implement a *Project Ambient Air Quality Monitoring Plan* for monitoring PM_{10} and $PM_{2.5}$ emissions during simultaneous construction, startup, and operational activities.[298] The plan identifies protocols for managing any exceedances of the NAAQS/AAAQS observed during monitoring.

211. We note that Table 4.15.4-1 in the final EIS incorrectly reported the estimated construction emissions for the Prudhoe Bay Treatment Plant.[299] The correct estimated

[294] Final EIS at 4-964.

[295] *Id*. at 5-43.

[296] *Id*. 4-975.

[297] *Id*. at 4-661.

[298] *Id*. at 4-975.

[299] The correct numbers are set forth in Table 4.14.4-1 in the draft EIS, as modified in AGDC's September 18, 2019 filing which updated construction emissions

emissions range between 20-43 percent lower than those set forth in the final EIS; because these estimated emissions are much lower, the conclusions set forth in the final EIS are unchanged.

212. Based on the above discussion, the final EIS concludes that adverse impacts on air quality due to normal project operation would generally be minor to moderate. Emissions could exceed nitrogen and sulfur deposition thresholds and visibility thresholds at nearby Class I and II nationally designated protected areas, but additional mitigation measures could be implemented during the ADEC air permitting phase that would reduce these impacts.[300] During the years of simultaneous construction, startup, and operational activities at the Liquefaction Facilities, emissions could exceed the NAAQS/AAAQS for PM_{10} and $PM_{2.5}$. As noted above, AGDC would implement an *Ambient Air Quality Monitoring Plan* to ensure air quality standards would not be exceeded. Activities such as flaring could result in short-term significant effects on air quality.

213. As noted above, Table 4.15.4-1 in the final EIS incorrectly reported the Prudhoe Bay Treatment Plant construction emissions, including carbon dioxide equivalent (CO_{2e}) construction emissions. The final EIS reported total construction GHG emissions for the Prudhoe Bay Treatment Plant as 622,371 metric tons CO_{2e}. The correct total is 364,971 metric tons CO_{2e}.[301]

214. The final EIS estimates GHG construction emissions (over the total eight years of construction) of about 2.2 million metric tons of CO_{2e}. The estimate for annual operational GHG emissions is about 9.91 million metric tons of CO_{2e} without maximum flare,[302] and about 16.3 million metric tons of CO_{2e} with maximum flare.[303]

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calculations to reflect AGDC's revised construction schedule. *See* AGDC Response to Recommended Environmental Condition 69, Accession No. 20190918-5098.

[300] *Id*. at 5-43.

[301] AGDC September 19, 2019 Response to Recommended Environmental Condition 69, Accession No. 20190918-5098.

[302] Maximum flare events apply to operation of the Prudhoe Bay Treatment Plant and Liquefaction Facilities. CO_2 and hydrocarbon flares would operate at maximum capacity only during emergency events, maintenance, and startup and shutdown events, assumed to be 500 hours per year for emission calculation purposes. *See* final EIS at Table 4.15.5-1, fn c.

[303] *Id.* at section 4.15, Tables 4.15.4-1, 4.15.4-2, 4.15.4-3, 4.15.4-4, 4.15.4-5 (construction emissions by construction year); Tables 4.15.5-1, 4.15.10, 4.15.5-11, 4.15-

215. To provide context, we are providing a comparison between the direct operational emissions of GHGs of the project to the Alaska and National GHG Inventories. Operation of the project will result in a range of about a 30-47 percent increase[304] in the annual fossil-fuel combustion inventory in Alaska based upon the 2017 GHG fossil fuel Inventory.[305] From a national perspective, direct operational GHG emissions would result in a range of 0.17–0.28 percent increase in national GHG emissions.[306] Currently, there are no national targets to use as benchmarks for comparison.[307] Additionally, we are unaware of any GHG emission reduction goals established either at the federal level or by the State of Alaska.

216. The final EIS acknowledges that the quantified GHG emissions from the construction and operation of the project would increase the atmospheric concentration of GHGs in combination with past and future emissions from all other sources and

.5-11, 4.15.5-12, 4.15.5-13, 4.15.5-14, 4.15.5-15, 4.15.5-3, and 4.15.5-20 (annual operational emissions).

[304] The range is based upon normal vs. maximum flaring of the Prudhoe Bay Treatment Plant and Liquefaction Facilities. Normal operational result in an 87 percent increase, while with both the Prudhoe Bay Treatment Plant and Liquefaction Facilities conducting maximum flaring would result in a 101 percent increase. Note the 30-47 percent increase is due in part to the low levels of current emissions within Alaska. The state currently emits only about 0.7 percent of the total U.S. GHG emissions (2016 data) and is the 40th highest emitter of the 50 states.

[305] U.S. Energy Information Administration, State Carbon Dioxide Emissions Data, State of Alaska grand total data for 2017 (Oct. 23, 2019). Alaska 's 2017 fossil-fuel derived CO_2 inventory was 34.2 million metric tons. ADEC released its 2015 GHG Inventory in January 2018, with the 2015 annual inventory (inclusive of sources and sinks) of 39.56 million metric tons. A comparison between direct project emissions and the Alaska 2015 GHG Inventory shows an increase of between 25 and 41 percent in GHG emissions due to project operation. *Alaska Greenhouse Gas Emissions Inventory, 1990 – 2015*, ADEC, Division of Air Quality (Jan. 30, 2018).

[306] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 - 2018, 2018 Data, Table ES-2 (Apr. 2020).

[307] The national emissions reduction targets expressed in the EPA's Clean Power Plan were repealed, Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emissions Guidelines Implementing Regulations, 84 Fed. Reg. 32,520, 32,522-32, 532 (July 8, 2019), and the targets in the Paris climate accord are pending withdrawal.

contribute incrementally to future climate change impacts.[308] Without either the ability to determine discrete resource impacts or an established target to compare GHG emissions against, the final EIS concludes that it cannot determine the significance of the project's contribution to climate change.[309] We agree with this finding. As the Commission has previously concluded, we have neither the tools nor the expertise to determine whether project-related GHG emissions will have a significant impact on climate change and any potential resulting effects, such as global warming or sea level rise.[310] The Commission has also previously concluded it could not determine whether a project's contribution to climate change would be significant.[311]

217. Finally, in addition to the project's potential effects on climate change, climate change related impacts (e.g., sea level changes and temperature increases) could affect project facilities. AGDC considered the Prudhoe Bay Treatment Plant facility and trestle height to account for potential future effects of climate change on the project area, including potential sea level changes, coastal erosion near the facility, and temperature increases.[312]

16. <u>Noise</u>

218. Noise from construction of the Mainline Pipeline would last from approximately 6 to 12 weeks at any point along the route, while noise from construction of aboveground facilities would last for months to years at each site. For the Mainline Pipeline, directional micro-tunneling crossings are planned for several river crossings; noise due to

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[308] Final EIS at 4-1221.

[309] *Id*. at 4-1124.

[310] *Jordan Cove Energy Project L.P.,* 170 FERC ¶ 61,202, at P 262 (2020); (*citing Rio Grande LNG, LLC*, 170 FERC ¶ 61,046, at P 108 (2020)).

[311] *Id*. *See generally Transcontinental Gas Pipe Line Co., LLC*, 171 FERC ¶ 61,032 (2020) (McNamee, Comm'r, concurring at PP 63-74) (elaborating on how the Social Cost of Carbon is not a useful tool for determining whether GHG emissions are significant and that it is not appropriate for the Commission to establish its own criteria for determining the significance of GHG emissions out of whole cloth).

[312] *Id*. at 4-1222. For example, AGDC incorporated the potential effects of climate change on the Prudhoe Bay Treatment Plant into the project design, listing Best Available Control Technology-level control for GHG emissions at the Prudhoe Bay Treatment Plant as operational efficiency measures, such as the use of waste heat recovery units to increase efficiency on combustion turbines.

directional micro-tunneling activities at Noise Sensitive Areas (NSA) within one mile of the entry or exit sites at the Yukon, Tanana Chulitna River crossings would be less than the recommended sound level of 55 A-weighted decibel (dBA) day-night average sound level (Ldn).[313]

219. As noted above, AGDC would incorporate the use of the directional micro-tunneling continuation methodology for the shoreline crossings at Beluga Landing and Suneva Lake, if feasible. If this should occur, the EIS recommends, and Environmental Condition 31 requires, that AGDC complete a noise impact analysis for any NSA located within one mile of these sites, and provide noise mitigation if the noise estimates for the directional micro-tunneling continuation activities are greater than 55 dBa Ldn at any of the nearby NSAs.

220. Noise due to directional micro-tunneling activities has the potential to affect sound levels at nearby key observation points, which could affect user experiences at these sites. Noise from the directional micro-tunneling crossings of the Yukon and Tanana Rivers would be perceptible at nearby key observation points but would not noticea increase existing sound levels at these sites. Noise from the directional micro-tunneling crossing of the Chulitna River would be perceptible at key observation points O and P (i.e., the Upper and Lower Troublesome Creek Trailheads, respectively), and would likely increase existing sound levels at these sites. No key observation points are present near the proposed directional micro-tunneling crossings of the Middle Fork Koyukuk and Deshka Rivers.

221. NSAs are present within one mile of the Coldfoot and Healy Compressor Stations and the Liquefaction Facilities. Noise due to construction of the Coldfoot Compressor Station would be perceptible at the nearest NSA, but within the recommended sound level of 55 dBA Ldn. Noise due to construction of the Healy Compressor Station would be perceptible at the nearest NSA and exceed our recommended sound level during the day,

[313] Final EIS at 4-977. In 1974, the EPA published *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin on Safety*, which evaluated the effects of environmental noise with respect to health and safety. As set forth in this publication, the EPA determined that noise levels should not exceed an Ldn of 55 dBA, which is the level that protects the public from activity interference and annoyance with indoor and outdoor activities. The Commission adopted this criterion for new compression facilities, LNG facilities, and associated pipeline facilities, and it is used here to evaluate the potential noise effects from operation of the Prudhoe Bay Treatment Plant facilities, compressor stations and the heater station associated with the Mainline Pipeline, and Liquefaction Facilities. *See* 18 C.F.R. § 157.206(b)(5) (2019).

with Ldn noise levels increasing by 10.0 decibels (dB). Based on comments received from the NPS, staff applied the equivalent sound level exceeded 50 percent of the time (L_{50}) noise level—used by the NPS for development management policies—in the analysis of construction noise impacts for the Healy Compressor Station; the L_{50} daytime noise levels would increase by 16.6 dB.[314] Based on these values, the final EIS concludes that impacts would be moderate to high during construction at the Healy Compressor Station.[315]

222. Noise due to construction of the Liquefaction Facilities would be perceptible and exceed our recommended sound level at three NSAs, with noise levels increasing by 15.7 to 26.5 dB at these sites. Construction activities at the Liquefaction Facilities would also increase noise levels at key observation point 54 (Mt. Redoubt Church) by 24.1 to 26.5 dBA, which would be clearly noticeable. To minimize impacts, AGDC would file a *Noise Mitigation Plan* for the Liquefaction Facilities, including measures to reduce construction noise by at least 10 dB at affected NSAs, monitoring of noise during construction, and procedures for resolving complaints regarding noise.[316]

223. Construction of the Mainline Pipeline and aboveground facilities (including the development of material extraction sites) would require blasting in areas of shallow bedrock or permafrost. Noise impacts on NSAs from these activities would be limited due to the temporary nature and short duration of blasting.[317] Noise from blasting could affect subsistence resources in two areas, but impacts would be minimized by restricting blasting during sensitive wildlife periods, using blasting mats or pads to reduce noise, and monitoring nearby nests and denning sites during blasting.[318]

224. Noise from operation of the Coldfoot and Healy Compressor Stations would be perceptible at the nearest NSAs, but within our recommended sound level of 55 dBA Ldn. Noise from operation of the Coldfoot Compressor Station would also be perceptible at the nearby Arctic Interagency Visitor Center, but within our recommended sound level of 55 dBA Ldn.[319] To ensure that noise levels due to operation of the Coldfoot and Healy

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[314] *Id*. at 4-1000.

[315] *Id*. at 5-33.

[316] *Id*.

[317] *Id*. at 4-494.

[318] *Id*.

[319] *Id*. at 4-999.

Compressor Stations would comply with the Commission's sound level requirement, AGDC would file a noise survey no later than 60 days after placing each compressor station in service. Additionally, the NPS commented that noise levels at the Healy Compressor Station would need to comply with a standard of 40 dBA L_{eq} at the Denali National Park border per the conditions of the Denali National Park Backcountry Management Plan.[320]

225. Noise due to operation of the Liquefaction Facilities would be within the Commission's recommended sound level of 55 dBA Ldn at nearby NSAs, but the noise would be perceptible, with sound intensity doubling at two NSAs.[321] Noise from operation of the Liquefaction Facilities at key observation point 54 (Mt. Redoubt Church) would be between 47 and 53 dBA Ldn, which is similar to existing background conditions at this site. To ensure that noise levels due to operation of the Liquefaction Facilities would be below our recommended threshold, AGDC would file noise surveys no later than 60 days after placing each liquefaction train in service and no later than 60 days after placing the entire Liquefaction Facilities into service.[322] If the noise attributable to operation of the equipment at the Liquefaction Facilities exceeds an Ldn of 55 dBA at the nearest NSA under interim or full horsepower load conditions, AGDC would file a report on what changes are needed and install the additional noise controls to meet the level within 1 year of the in-service date.[323]

226. Blowdowns would occur at compressor stations and mainline valves as part of normal pipeline safety operations. AGDC would install silencers on blowdown equipment at each compressor station to ensure that noise associated with blowdowns would be less than 55 dBA Ldn at nearby NSAs.[324] Mainline valves with NSAs greater than one mile from the site would be outfitted with standard vent mufflers, which would reduce noise from blowdown events at the nearest NSAs to 64 dBA L_{eq} or less. Nighttime blowdowns at these sites could result in perceptible noise at NSAs, but this would be infrequent and impacts would be temporary.[325] AGDC would install increased

[320] *Id*.

[321] *Id*. at 1011.

[322] *Id*.

[323] *Id*.

[324] *Id*. at 4-1012.

[325] *Id*.

performance vent silencers at three Mainline Valves (Nos. 27, 28, and 29) where NSAs would be within 0.5 mile to reduce the noise from blowdowns at these sites.

227. Operation of the ground-level and elevated low-pressure flares at the Liquefaction Facilities would generate noise between 45 and 78 dBA Ldn at durations ranging from less than 1 hour to 36 hours. To minimize impacts, AGDC would schedule most flare events in coordination with the local community and outside potentially sensitive timeframes.[326] Because of the intensity and potential duration of these flare events and the associated noise levels, AGDC would file a *Flare Noise Mitigation Plan* that addresses mitigation of noise impacts due to flaring, including procedures for contacting the local community and scheduling flaring events.[327]

228. During project construction and operation, air traffic at regional airports and airstrips would increase to transport workers, equipment, and supplies. Additionally, 48 helipads would be built along the Mainline Pipeline to support construction, 28 of which would be retained for operation. The increased air traffic and use of the helipads would result in periodic and temporary increases in noise.[328]

229. Most noise impacts during construction would be temporary and minor. Construction noise would have a minor to moderate effect on NSAs or key observation points. Construction of the Liquefaction Facilities would have a moderate to significant effect on noise at NSAs and a key observation points, but AGDC would file a mitigation plan to reduce these impacts. Project operation would have permanent impacts on ambient noise conditions at aboveground facilities. The direct effects on noise levels in the project area would be minor to moderate during normal facility operation, with the exception of operational noise associated with the Liquefaction Facilities at the two nearest NSAs. AGDC would conduct noise surveys and implement additional controls as needed to meet FERC's noise criteria.

17. **Health**

230. AGDC's *Health Impact Assessment* relied on the methodology used to rate health impacts followed by Alaska Department of Health and Human Services' guidelines for health impact assessments.[329] These guidelines evaluate eight health effects categories

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[326] *Id*.

[327] *Id*.

[328] *Id*.

[329] *Id*. at 4-1013.

(HEC) by assigning potential impacts a rating of low, medium, high, or very high based on the potential severity of the impact and the likelihood that an impact would occur.[330] Health severity is evaluated using a numeric scale of 1 to 4 based on the duration, extent, frequency, and magnitude of the health outcome. The likelihood of the impact is then determined according to Alaska Department of Health and Human Services' likelihood scale.[331] Positive impacts as well as adverse impacts are assessed using this methodology.

231. For project construction, the results of the *Health Impact Assessment* rated one HEC as high adverse (infectious diseases); three HECs as medium adverse (social determinants of health; accidents and injuries; and food, nutrition, and caribou subsistence activity); and all other HECs as low adverse.[332] For project operation, the *Health Impact Assessment* rated three HECs as medium adverse (social determinants of health; accidents and injuries; and infectious disease); and all other HECs as low adverse.[333] Potential positive effects were also identified, including increased employment opportunities and household incomes and future improvements to air quality in the Fairbanks area through conversion from other fuels to natural gas. Potential mitigation measures identified by AGDC include worker segregation, community engagement, implementation of health education programs, and training and safety planning.[334]

18. **Reliability and Safety**

232. Multiple federal agencies share regulatory authority over the LNG, pipeline, and gas treatment facilities. The safety, security, and reliability of various aspects of the project would be regulated singularly or jointly by PHMSA, the Coast Guard, Transportation Security Administration, Cybersecurity and Infrastructure Security

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[330] *Id*. at 1026.

[331] *Id*.

[332] *Id*.

[333] *Id*.

[334] *Id*. Tables 4.17.3-1 and 4.17.3-2 present summaries, organized according to HECs, of the health impacts that AGDC determined could result from project construction and operation, respectively. All ratings presented in Tables 4.17.3-1 and 4.17.3-2 are from AGDC's *Health Impact Assessment*. Also included in the tables are the recommendations that the *Health Impact Assessment* provided to mitigate or prevent adverse impacts.

Agency, Occupational Safety and Health Administration (OSHA), EPA, and the Commission.

233. PHMSA establishes and has the authority to enforce safety standards for the Liquefaction Facilities, pipelines, and compressors. As noted above, pursuant to the MOU between PHMSA and the Commission, on February 4, 2020, PHMSA provided a Letter of Determination (LOD) to the Commission indicating that AGDC has demonstrated that the siting of the Liquefaction Facilities complies with the federal safety standards for siting under 49 C.F.R. Part 193, Subpart B.[335] In addition, DOT has issued four Special Permits related to 49 C.F.R. Part 192[336] requirements for strain-based design, multi-layer coating, Mainline Valve spacing, crack arrestor spacing for the Mainline Facilities, and one Special Permit to Part 193 requirements for pipe-in-pipe technology for the Liquefaction Facilities.[337]

234. The Coast Guard exercises regulatory authority over the safety and security of port areas and navigable waterways, including waterfront facilities handling LNG and LNG marine vessels.[338] Under the regulations, the Coast Guard issues a Letter of Recommendation (LOR) to the Commission on the suitability of the waterway for the LNG marine vessel traffic associated with the proposed waterfront facilities handling LNG. On August 17, 2017, the Coast Guard issued a LOR concluding that Cook Inlet is a suitable waterway for LNG marine traffic.[339] On June 23, 2016, the Coast Guard also issued a conditional letter approving the use of a cryogenic pipe-in-pipe installation as an alternative to conventional containment for the LNG marine transfer piping.

235. The final EIS assesses potential impacts to the human environment in terms of safety and whether the proposed facilities would operate safely, reliably, and securely.

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[335] *See* 49 C.F.R. pt. 193, Subpart B (2019). If the Alaska LNG Project is authorized and constructed, it would be subject to PHMSA's inspection and enforcement program. The final determination of whether the project complies with the requirements set forth in these regulations would be made by PHMSA staff.

[336] 49 C.F.R. pt. 192 (2019).

[337] 49 C.F.R. pt 193 (2019). *See also* final EIS at 4-1144.

[338] 46 C.F.R. pt. 154 (2019).

[339] Final EIS at 4-1156. If the project is authorized and constructed, the Liquefaction Facilities would be subject to the Coast Guard's inspection and enforcement program to ensure compliance with the requirements of 33 C.F.R. pt. 105 (2019) and 33 C.F.R. pt. 127 (2019).

Commission staff conducted a preliminary engineering and technical review of the Alaska LNG Project, including potential external impacts based on the site locations.[340] Based on this review, the final EIS recommends additional mitigation measures for implementation prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout the life of the facility, to enhance the reliability and safety of the facility. With these measures, the final EIS concludes that acceptable layers of protection or safeguards would reduce the risk of a potentially hazardous scenario from developing that could impact the off-site public, with the exception of potential incidents from high pressure piping at the Prudhoe Bay Treatment Plant described above where staff could not make that determination based on the information provided by AGDC.[341] The final EIS indicates that the Prudhoe Bay Treatment Plant facilities and these hazards would be located within Alaska's Prudhoe Bay Unit area, which is not accessible to the general public without an escort, but may extend onto the adjacent Prudhoe Bay Unit Central Gas Facility plant and Prudhoe Bay Treatment Plant operator camp site. In addition, the final EIS recommends, and Environmental Condition 51 requires, that emergency response plans (ERP) for potential large ruptures at the Prudhoe Bay Treatment Plant be coordinated with the adjacent Prudhoe Bay Unit Central Gas Facility plant and include consideration of impacts on the Prudhoe Bay Treatment Plant operator camp site. In addition, the EIS recommends, and Environmental Condition 49 requires, that AGDC provide additional information on hazard modeling of incidents from the high pressure piping to inform the ERP. These recommendations and all other reliability and safety recommendations proposed in the final EIS have been adopted as Environmental Conditions 32-164 with clarification on Environmental Conditions 48, 132, 133, and 165 that they apply to the Liquefaction Facilities and/or Prudhoe Bay Treatment Plant, but not the entire Project.

19. <u>Cumulative Impacts</u>

236. The final EIS assessed the cumulative impacts of the proposed Alaska LNG Project with other projects within the same geographic and temporal scope.[342]

237. The types of other projects evaluated in the final EIS include non-jurisdictional facilities, as well as energy, transportation, mining, marine and other projects. For example, the analysis considered: modifications/new facilities at the Point Thomson Unit; modification/new facilities at the Prudhoe Bay Unit Prudhoe Bay Major Gas Sales

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[340] *Id*. at section 4.18.

[341] *Id*. at 5-47.

[342] *Id*. at 4-1158 – 4-1222.

Project; relocation of the Kenai Spur Highway; upgrades to the City of Kenai water system; in-state gas interconnections; and LNG carrier transits to and from the Liquefaction Facilities during operation of the Alaska LNG Project.[343]

238. The final EIS concludes that cumulative impacts would not be significant for the majority of resources where a level of impact could be ascertained, including geology; soils; groundwater; surface and marine waters; most vegetation types; terrestrial wildlife; aquatic species; threatened, endangered, and special status species; land use, recreation, and special use areas; most socioeconomic indicators; transportation; cultural resources; air quality; most noise; and public health and safety.[344] However, the Alaska LNG Project would have significant, long-term to permanent impacts on permafrost, wetlands, forest, caribou (Central Artic Herds), some noise, and socioeconomics (population), and because other projects in the study area would similarly affect these resources, the final EIS found that cumulative impacts on these resources would be significant.[345]

20. <u>Alternatives</u>

239. The final EIS analyzed a number of alternatives to the project and its various components including the no action alternative, system alternatives, LNG terminal site alternatives, and pipeline route alternatives and variations.[346] As discussed above, under the no action alterative, the impacts described in the EIS would not occur, but the purpose and need of the project would not be met.

240. The Matanuska-Susitna Borough (MSB) requested an evaluation of an alternative liquefaction facilities site north of Anchorage near Port MacKenzie on the west bank of the Knik Arm in Cook Inlet. The MSB filed numerous comments and provided supplemental data supporting the use of the Port MacKenzie alternative. The final EIS analyzes the alternative and concludes that the alternative has some advantages, including a shorter mainline pipeline length, avoidance of the Cook Inlet pipeline crossing, and elimination of the need to relocate the Kenai Spur Highway. However, the project has other advantages over the Port MacKenzie Alternative. While both alternatives would affect beluga whales during construction of marine facilities, the probability of impacts, such as vessel strikes during operation of the liquefaction facilities, would be greater with the Port MacKenzie Alternative, particularly in the summer months. Operational air

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[343] *Id*. at 4-1159 – 4-1160.

[344] *Id*. at 5-48.

[345] *Id*.

[346] *Id*. at 3-2 – 3-49.

emissions would be greater for the Port MacKenzie Alternative owing to the increased shipping transit distances. Ice conditions in Upper Cook Inlet could hamper the ability to deliver the proposed export volumes required to meet the project's principal commercial objective relative to the proposed site at Nikiski. Moreover, the Port MacKenzie Alternative would provide for only two of the three delivery points proposed by the project.[347] The final EIS concludes that, overall, the alternative's environmental advantages are not sufficient to offset operational environmental impacts stemming from the increased vessel traffic in Upper Cook Inlet and that the Port Mackenzie Alternative would not provide a significant environmental advantage over the proposed Nikiski site.

241. The City of Valdez filed comments and supplemental data supporting the use of an alternative site for the liquefaction facilities, referred to as the Anderson Bay Alternative. The alternative site is adjacent to Prince William Sound within the Valdez city limits. One advantage of the Anderson Bay Alternative is that the mainline pipeline required to reach the Anderson Bay site would lie within or adjacent to the TAPS corridor for all or most of its length from Livengood to the TAPS terminal at Valdez. In contrast, only about 190 miles (23 percent) of the proposed Mainline Pipeline would lie adjacent to transportation corridors or within BLM-designated utility corridors. This would allow for some reductions of impacts on previously undisturbed areas. A pipeline to the Anderson Bay site would be comparable in length to the proposed Mainline Pipeline but would avoid crossing Cook Inlet. However, future laterals from interconnection points for in-state deliveries of natural gas would require constructing an additional 113 miles of pipeline to reach markets in Fairbanks and Anchorage, relative to the project.

242. With respect to the Anderson Bay site itself, liquefaction facilities at this location would require extensive civil design work and terracing. Thus, while the Anderson Bay Alternative would avoid impacts associated with construction of a pipeline across Cook Inlet, development of the Anderson Bay liquefaction site would result in greater marine impacts than development of the proposed site.

243. AGDC identified other constraints regarding the use of the Anderson Bay site. The entrance into the Port of Valdez would be through the Valdez Narrows, which is less than 1 mile wide. After being loaded with LNG, a safety zone would be established around LNG carriers, which would restrict other vessel traffic through the Valdez Narrows or prevent the LNG carrier from exiting into Prince William Sound until vessel traffic cleared. AGDC indicated that unexpected delays or uncertainty in vessel transit would be greater than with the proposed site. For the reasons described above, the final EIS concludes that the Anderson Bay site would not provide a significant environmental advantage over the proposed site.

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[347] *Id*. at Table 3.8.1-1 compares the Port MacKenzie site environmental advantages and disadvantages compared with the proposed Nikisi site.

244. The final EIS evaluates alternative routes for the Mainline Pipeline, including the Cook Inlet East and Cook Inlet West Alternatives. The public provided comments regarding the Cook Inlet West Alternative. The analysis of the alternative routes considered area of impact, constructability, land uses affected, and wildlife and aquatic impacts. The final EIS finds that neither the Cook Inlet East Alternative nor the Cook Inlet West Alternative would provide a significant environmental advantage over the project as proposed.

245. The draft EIS evaluated an alternative route through the Denali National Park (the Denali Alternative) and compared it to the then-proposed route for the Mainline Pipeline. After the publication of the draft EIS, AGDC adopted the Denali Alternative as the proposed project route. Accordingly, at the request of cooperating agencies, the final EIS revises the analysis to compare the currently proposed route—inclusive of the Denali Alternative—with suggested alternatives that include the route previously proposed by AGDC, which is referred to as the Denali Avoidance Alternative. The final EIS finds that the selection of either the proposed route or the Denali Avoidance Alternative would be acceptable, without significant environmental advantages from either. Therefore, it concludes that the Denali Avoidance Alternative would not provide a significant environmental advantage over the proposed route.

246. In response to comments received, the final EIS evaluates an alternative route for the Mainline Pipeline that passes closer to Fairbanks (the Fairbanks Alternative). On balance, however, the final EIS concludes that impacts on land, water, and other resources would be greater for the Fairbanks Alternative than the proposed route. Therefore, it concludes that the Fairbanks Alternative would not provide a significant environmental advantage over the project.

247. The final EIS reviews alternatives to the project employing an independent analysis and using the comments received. Although many of the alternatives appear to be technically feasible, the review identified no alternatives that would provide a significant environmental advantage over the project. Based on these findings, the final EIS concludes that the proposed project, as modified by the required mitigation measures contained in this order, is the preferred alternative than can meet the project objectives.

c. **Comment Received After Issuance of the Final EIS**

248. On April 13, 2020, EPA filed comments acknowledging that in response to its comments on the draft EIS, staff developed additional mitigation measures that AGDC agreed to implement. EPA requests that these measures be included in the Commission's final order on the Alaska LNG Project as specific conditions.[348] EPA also requests that

[348] EPA April 13, 2020 Comments at 1.

the Commission order include a summary of mitigation plans that are currently being developed to reduce wetlands impacts and operational emissions associated with the project, as well as the CWA section 401 certification for the portion of the mainline pipeline constructed in the Denali National Park.[349]

249. The mitigation measures recommended in the final EIS are included as conditions to this order. As discussed above, with respect to mitigation measures to which AGDC has committed, Environmental Condition 1 requires AGDC to follow the construction procedures and mitigation measures identified in the EIS, including Appendix X which sets forth the recommended mitigation measures included in the draft EIS to which AGDC has committed and incorporated into the proposed action considered here. As also discussed above, AGDC may not commence construction of the project until it provides certain outstanding information and confirm they have received all applicable authorizations required under federal law.[350]

d. Environmental Conclusions

250. We have reviewed the information and analysis contained in the final EIS regarding potential environmental effects of the project, as well as other information in the record. We are adopting the environmental recommendations in the final EIS, as modified herein, and include them as conditions in the appendix to this order. Compliance with the environmental conditions appended to our orders is integral to ensuring that the environmental impacts of approved projects are consistent with those anticipated by our environmental analyses. Thus, Commission staff carefully reviews all information submitted. Commission staff will only issue a construction notice to proceed with an activity when satisfied that the applicant has complied with all applicable conditions. We also note that the Commission has the authority to take whatever steps are necessary to ensure the protection of environmental resources during construction and operation of the project, including authority to impose any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the order, as well as the avoidance or mitigation of unforeseen adverse environmental impacts resulting from project construction and operation.[351]

251. We agree with the conclusions presented in the final EIS and find that if the project is constructed and operated as described in the final EIS, the environmental impacts associated with the project are acceptable considering the public benefits that will be provided by the project. The final EIS finds that, although the project would

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[349] Id. at 1-2.

[350] *See supra* at P 30.

[351] *See* Environmental Conditions 2 and 3.

result in temporary, long-term, and permanent impacts on the environment, some of which would be significant, most impacts would be reduced to less-than-significant levels if the project is constructed and operated in accordance with applicable laws and regulations and the environmental mitigation measures recommended in the final EIS and required by this order. For these reasons, we find that the Alaska LNG Project is not inconsistent with the public interest.

252. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this authorization. The Commission encourages cooperation between applicants and local authorities. However, this does not mean that state and local agencies through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.[352]

IV. Conclusion

253. At a hearing held on May 21, 2020, the Commission on its own motion received and made part of the record in this proceeding all evidence, including the application, as supplemented, and exhibits thereto, and all comments, and upon consideration of the record,

The Commission orders:

(A) AGDC is authorized under section 3 of the NGA to site, construct, and operate its Alaska LNG Project, as described and conditioned herein and as more fully described in its application and supplements, including any commitments made therein, subject to the environmental conditions contained in the appendix to this order.

(B) AGDC's proposed facilities shall be constructed and made available for service within ten years of the date of this order.

(C) AGDC shall notify the Commission's environmental staff by telephone, e-mail, or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies AGDC. AGDC shall file

[352] *See* 15 U.S.C. § 717r(d) (state or federal agency's failure to act on a permit considered to be inconsistent with Federal law); *see also Schneidewind v. ANR Pipeline Co*., 485 U.S. 293, 310 (1988) (state regulation that interferes with FERC's regulatory authority over the transportation of natural gas is preempted) and *Dominion Transmission, Inc. v. Summers*, 723 F.3d 238, 245 (D.C. Cir. 2013) (noting that state and local regulation is preempted by the NGA to the extent it conflicts with federal regulation, or would delay the construction and operation of facilities approved by the Commission).

written confirmation of such notification with the Secretary of the Commission within 24 hours.

By the Commission. Commissioner Glick is dissenting with a separate statement attached.
Commissioner McNamee is concurring with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

Appendix

Environmental Conditions

1. Alaska Gasline Development Corporation (AGDC) shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to staff information requests) and as identified in the environmental impact statement (EIS), unless modified by the Order. AGDC must:

   a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);

   b. justify each modification relative to site-specific conditions;

   c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

   d. receive approval in writing from the Director of the Office of Energy Projects (OEP), or the Director's designee, **before using that modification.**

2. For the Prudhoe Bay Treatment Plant and Liquefaction Facilities, the Director of the OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the Order and take whatever steps are necessary to ensure the protection of life, health, property, and the environment during Alaska LNG Project (Project) construction and operation. This authority shall allow:

   a. the modification of conditions of the Order;

   b. stop-work authority and authority to cease operation; and

   c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the Order as well as the avoidance or mitigation of unforeseen adverse environmental impact resulting from Project construction and operation.

3. For the pipeline facilities (e.g., Mainline Facilities, Prudhoe Bay Unit Gas Transmission Line, and Point Thomson Unit Gas Transmission Line), the Director of the OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the

conditions of the Order, and take whatever steps are necessary to ensure the protection of environmental resources during construction and operation of the Project. This authority shall allow:

a. the modification of conditions of the Order;

b. stop-work authority; and

c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the Order as well as the avoidance or mitigation of unforeseen adverse environmental impact resulting from Project construction and operation.

4. **Prior to any construction,** AGDC shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, environmental inspectors (EIs), and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

5. The authorized facility locations, including the directional micro-tunneling continuation methodology at the Cook Inlet shoreline crossing, if implemented, and the revisions required in conditions 19 and 29, shall be as shown in the EIS, as supplemented by filed alignment sheets. **As soon as they are available, and before the start of construction,** AGDC shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000, with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

6. AGDC shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in

writing by the Director of the OEP, or the Director's designee, **before construction in or near that area**.

This requirement does not apply to extra workspace allowed by FERC's Upland Erosion Control, Revegetation and Maintenance Plan and/or minor field realignments per landowner needs and requirements that do not affect other landowners or sensitive environmental areas such as wetlands. Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;

b. implementation of endangered, threatened, or other special status species mitigation measures;

c. recommendations by state regulatory authorities; and

d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

7. **At least 60 days before construction begins**, AGDC shall file an Implementation Plan with the Secretary for the review and written approval of the Director of the OEP, or the Director's designee. AGDC must file revisions to the plan as schedules change. The plan shall identify:

a. how AGDC will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff information requests and FERC staff recommendations in the draft EIS agreed to by AGDC [*see* appendix X]) and as identified in the EIS and required by the Order;

b. how AGDC will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to on-site construction and inspection personnel;

c. the number of EIs assigned per spread and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;

d. company personnel, including EIs and contractors, who will receive copies of the appropriate material;

e. the location and dates of the environmental compliance training and instructions AGDC will give to all personnel involved with construction and restoration (initial and refresher training as the Project progresses and personnel change), with the opportunity for OEP staff to participate in the training sessions;

f. the company personnel (if known) and specific portion of AGDC's organization having responsibility for compliance;

g. the procedures (including use of contract penalties) AGDC will follow if noncompliance occurs; and

h. for each discrete facility, a Gantt or PERT chart (or similar Project scheduling diagram), and dates for:

   i. the completion of all required surveys and reports;
   ii. the environmental compliance training of on-site personnel;
   iii. the start of construction; and
   iv. the start and completion of restoration.

8. AGDC shall employ a team of EIs per construction spread (the number per spread to be determined by the Director of the OEP, or the Director's designee). The EIs shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;

b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 7 above) and any other authorizing document;

c. empowered to order correction of acts that violate the environmental conditions of the Order and any other authorizing document;

d. a full-time position, separate from all other activity inspectors;

e. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

f. responsible for maintaining status reports.

9. Beginning with the filing of its Implementation Plan, AGDC shall file updated status reports with the Secretary on a **monthly** basis for the aboveground facilities Prudhoe Bay Treatment Plant, Liquefaction Facilities, Mainline Pipeline compressor stations) and on a **weekly** basis during active construction of the pipeline facilities (Point Thomson Unit Gas Transmission Line, Prudhoe Bay Unit Gas Transmission Line, and Mainline Pipeline) until all construction and restoration activities are complete. Problems of a significant magnitude shall be reported to FERC **within 24 hours**. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

   a. an update on AGDC's efforts to obtain the necessary federal authorizations;

   b. project schedule, including the construction status of each spread and facility, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;

   c. a listing of all problems encountered, contractor nonconformance/deficiency logs, and each instance of noncompliance observed by the EIs during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

   d. a description of the corrective and remedial actions implemented in response to all instances of noncompliance, nonconformance, or deficiency;

   e. the effectiveness of all corrective and remedial actions implemented;

   f. a description of any landowner/resident complaints that may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and

   g. copies of any correspondence received by AGDC from other federal, state, or local permitting agencies concerning instances of noncompliance, and AGDC's response.

10. AGDC shall employ a special inspector during construction of the Liquefaction Facilities, and a copy of the special inspector's reports shall be included in the **monthly** status reports filed with the Secretary (see condition 9 above). The special inspector shall be responsible for:

a. observing the construction of the Project facilities to be certain it conforms to the design drawings and specifications;

b. furnishing inspection reports to the engineer- or architect-of-record and other designated persons. All discrepancies shall be brought to the immediate attention of the contractor for correction, and then if uncorrected, to the engineer- or architect-of-record; and

c. submitting a final signed report stating whether the work requiring special inspection was, to the best of his/her knowledge, in conformance with the approved plans and specifications and the applicable workmanship provisions.

11. AGDC shall develop and implement an environmental complaint resolution procedure, and file such procedure with the Secretary, for the review and written approval of the Director of the OEP, or the Director's designee. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during Project construction and right-of-way restoration. **Prior to construction,** AGDC shall mail the complaint procedures to each landowner whose property will be crossed by the Project.

a. In its letter to affected landowners, AGDC shall:

i. provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;

ii. instruct the landowners that if they are not satisfied with the response, they should call AGDC's Hotline; the letter should indicate how soon to expect a response; and

iii. instruct the landowners that if they are still not satisfied with the response from AGDC's Hotline, they should contact the Commission's Landowner Helpline at 877-337-2237 or at LandownerHelp@ferc.gov.

b. In addition, AGDC shall include in its **monthly** and **weekly** status reports (see condition 9 above) a copy of a table that contains the following information for each problem/concern:

i. the identity of the caller and date of the call;

ii. the location by milepost and identification number from the authorized alignment sheet(s) of the affected property;

iii. a description of the problem/concern; and

iv. an explanation of how and when the problem was resolved, will be resolved, or why it has not been resolved.

12. AGDC must receive written authorization from the Director of the OEP, or the Director's designee, **before commencing construction of any Project facilities**. To obtain such authorization, AGDC must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

13. AGDC must receive written authorization from the Director of the OEP, or the Director's designee, **prior to introducing hazardous fluids into the Project facilities**. Instrumentation and controls, hazard detection, hazard control, and security components/systems necessary for the safe introduction of such fluids shall be installed and functional.

14. AGDC must receive written authorization from the Director of the OEP, or the Director's designee, **before placing the Prudhoe Bay Treatment Plant and Liquefaction Facilities into service**. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with FERC approval and can be expected to operate safely as designed, and that the rehabilitation and restoration of areas affected by the Project are proceeding satisfactorily.

15. AGDC must receive written authorization from the Director of the OEP, or the Director's designee, **before placing the Mainline Facilities into service**. Such authorization will only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the Project are proceeding satisfactorily.

16. **Within 30 days of placing the authorized facilities in service**, AGDC shall file an affirmative statement with the Secretary, certified by a senior company official:

a. that the facilities have been constructed and installed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or

b. identifying which of the conditions in the Order AGDC has complied with or will comply with. This statement shall also identify any areas affected by the Project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

17. **Prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, or the Director's designee, a Project-wide acid rock drainage and metal leaching (ARD/ML) Management Plan that includes details for surface and groundwater monitoring in areas of moderate ARD/ML potential. (*section 4.1.3.10*)

18. **Prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary a revised Feasibility Crossing Study that provides updated site-specific geotechnical information for the Deshka River with additional borings conducted at the proposed crossing location. If the results of the study indicate that a modification to the crossing location or method is necessary, AGDC shall file, for the review and written approval of the Director of the OEP, or the Director's designee, a revised crossing plan for the Deshka River. (*section 4.1.5.5*)

19. **Prior to construction of the Mainline Facilities**, AGDC shall review areas proposed for Mode 4 construction in the summer and confirm that winter construction will not be feasible in low slope areas (0 to 2 percent). Additionally, AGDC shall use timber/synthetic mats in place of granular fill in wetlands proposed for Mode 4 construction on slopes of 0 to 2 percent and in uplands proposed for Mode 4 summer construction on slopes of 0 to 2 percent that are underlain by thaw-stable permafrost. AGDC shall prepare revised alignment sheets and resource impact tables adopting changes to Mode 4 areas reflecting the increase in winter construction segments and the replacement of granular fill with timber/synthetic mats. **Prior to construction of the Mainline Facilities**, AGDC shall file the revised sheets and resource impact tables with the Secretary for the review and written approval of the Director of the OEP, or the Director's designee. *(section 4.2.4)*

20. **Prior to placement of any granular fill**, AGDC shall conduct aggregate testing using sieve analysis to select granular fill with at least 20-percent fines for the surface layer used on all construction workspace, including Mode 4 work pads, temporary aboveground facilities, temporary access roads, etc. AGDC shall include the results of the aggregate tests in its construction status reports filed with the Commission. *(section 4.2.4)*

21. **Prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, or the

Director's designee, an updated assessment of piping erosion potential between mileposts (MP) 536.1 and 544.3 using the same methodology used for the rest of the Mainline Pipeline (Onshore Geohazard Assessment Methodology and Results summary). If any new areas of piping erosion potential are identified, AGDC shall implement the same mitigation measures that will be implemented for other areas with the potential for piping erosion, including the use of subdrains to control meltwater and groundwater recharge as well as prevent the development of a hydraulic gradient within the erodible soils underneath the pipe. *(section 4.2.5)*

22. **Prior to construction,** AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, or the Director's designee, an updated Unanticipated Contamination Discovery Plan that indicates the measures that will be taken in the event that contaminated sediments are discovered in marine water environments, including the appropriate agency notification requirements. Additionally, this plan shall be updated to include notification to the National Park Service in the event of an unanticipated discovery of contamination on National Park Service property. *(section 4.2.6)*

23. **During construction of the Mainline Facilities,** AGDC shall restrict the placement of granular fill, spoil, or other materials in waterbodies within the following workspaces:

    a. pipe storage yards "Chandalar PSY" in the Unnamed Tributary to North Fork Chandalar River near MP 174.6 and "65-9-078-2 FP" in the Unnamed Tributary to North Fork Ray River near MP 337.0; and

    b. disposal sites "WD-043" in Ninety-Six Creek near MP 251.8 and "WD-050" in the Unnamed Tributary to Prospect Creek near MP 281.5.

    In the event that the use of fill is unavoidable, then AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, or the Director's designee, site-specific justifications and measures it will use to preserve water flow and quality within the affected streams. (*section 4.3.2.4*)

24. **Following construction of the Prudhoe Bay Treatment Plant and Point Thomson Unit Gas Transmission Line,** AGDC shall conduct seasonal monitoring for a period of three years to track caribou herd movement and determine if project infrastructure is creating a barrier to caribou movement. To allow conclusions regarding any potential changes, AGDC shall also conduct baseline monitoring of caribou herd movement prior to the start of construction of the Prudhoe Bay Treatment Plant and Point Thomson Unit Gas Transmission Line. No later than six months after completion of the study following the third

year, AGDC shall file a report describing the results of the monitoring and recommendations to minimize or mitigate any identified issues with caribou movement related to the Project, for further consideration and potential action by the Commission**.**

25. **Prior to construction,** AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, or the Director's designee, revised shutdown distances for all underwater noise generating activities (i.e., pile driving [impact, vibratory, and all pile types], dredging, screeding, anchor handling, Mainline Pipeline shoreline installation, and Marine Terminal Material Offloading Facility removal). For the revised shutdown distances, AGDC shall establish:

    a. shutdown zones for Level A harassment for all marine mammals based on the modeled distances in appendix L-1, tables L-1.1-4, L-1.1-5, L-1.1-9, L-1.1-11, L-1.1-12, and L-1.1-13 of the EIS (pile driving activities shall stop until the animal moves out of the shutdown injury zone);

    b. shutdown zones for Level B harassment for Cook Inlet beluga whales based on the modeled distances in appendix L-1, tables L-1.1-10, L-1.1-11, L-1.1-12, and L-1.1-13 of the EIS (pile driving and dredging activities shall stop until the animal moves out of the shutdown harassment zone); and

    c. harassment zones for Level B harassment for all marine mammals (except Cook Inlet beluga whales) based on the modeled distances in appendix L-1, tables L-1.1-6, L-1.1-10, L-1.1-11, L-1.1-12, and L-1.1-13 of the EIS (activity noise levels shall be lowered when animals enter these zones, until they leave the area, if possible).

    Alternatively, AGDC may commit to conducting a Sound Source Verification during construction that will establish appropriate shutdown and harassment zones based on observed underwater noise levels. *(section 4.6.3.2)*

26. **Prior to construction**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, or the Director's designee, a revised Protected Species Observers (PSO) deployment plan that includes the following:

    a. for pile driving activities in Cook Inlet and Prudhoe Bay, AGDC shall station at least one PSO at-sea near the edge of the shutdown zone (for Level A) and one PSO stationed at-sea or on land near the edge of the harassment zone (for Level B); and station at least one PSO on the pile-driving barge, or in an adjacent land-based vantage point;

b. for anchor handling activities in Cook Inlet, AGDC shall station at least one PSO on the pipelay vessel; and

c. for dredging and screeding activities and Mainline Pipeline shoreline installation, AGDC shall station at least one PSO on each dredging and screeding vessel or accompanying vessel. *(section 4.6.3.2)*

27. **Prior to construction**, AGDC shall update its list of Alaska Waters Catalog waters affected by Project facilities using the most current Alaska Department of Fish and Game Anadromous Waters Catalog list and National Marine Fisheries Service Essential Fish habitat species list and apply the conservation measures at the appropriate waterbodies. AGDC shall file with the Secretary the revised list and the measures it will employ at each Alaska Waters Catalog water. (*section 4.7.1*)

28. **AGDC shall not begin construction until**:

a. FERC staff completes formal Endangered Species Act consultation with the U.S. Fish and Wildlife Service (USFWS) and National Marine Fisheries Service (NMFS);

b. AGDC has received applicable Incidental Take Authorizations per the Marine Mammal Protection Act from the USFWS and NMFS; and

c. AGDC has received written notification from the Director of the OEP, or the Director's designee, that construction or use of mitigation may begin. *(section 4.8.1)*

29. **Prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, or the Director's designee, a plan for the relocation of mainline valve 14 and its helipad, developed in coordination with Clear Air Force Station representatives. (*section 4.9.3*)

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

a. AGDC completes outstanding archaeological and architectural surveys and any special studies, and files with the Secretary all remaining cultural resources survey, evaluation, and special studies reports, and the Alaska

State Historic Preservation Office (SHPO) comments, the applicable land management agency comments, and consulting party comments on the reports;

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

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

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

All material filed with the Commission containing **location, character, and ownership information** about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: **"CUI/PRIV – DO NOT RELEASE."** *(section 4.13.5).*

31. If the directional micro-tunneling continuation methodology is used for the proposed shoreline crossings at Beluga Landing and Suneva Lake, then **prior to construction of the Mainline Facilities,** AGDC shall file with the Secretary noise impact calculations for any noise sensitive areas (NSAs) within 1 mile of these sites to reflect use of the directional micro-tunneling continuation methodology. If the noise impact estimates would result in noise attributable to directional micro-tunneling continuation activities greater than 55 A-weighted decibel (dBA) day-night average sound level (Ldn) at any of the NSAs, AGDC shall include proposed mitigation measures, for the review and written approval by the Director of the OEP, or the Director's designee, to ensure the estimated noise attributable to the directional micro-tunneling continuation activities is below 55 dBA Ldn. (*section 4.16.3.2*)

32. **Prior to construction of final design**, AGDC shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record registered in Alaska:

a. site preparation drawings and specifications for the Liquefaction Facilities and Prudhoe Bay Treatment Plant;

b. a list of the foundation systems to be used for each structure;

c. all Liquefaction Facilities and Prudhoe Bay Treatment Plant structures and foundation design drawings as well as associated calculations, including prefabricated and field constructed structures;

d. seismic specifications for procured equipment for the Liquefaction Facilities and Prudhoe Bay Treatment Plant; and

e. quality control procedures to be used for civil/structural design and construction.

In addition, AGDC shall file, in its Implementation Plan, the schedule for producing this information. (*section 4.18.9*)

33. **Prior to construction of final design**, AGDC shall file with the Secretary a monitoring and maintenance plan, stamped and sealed by the professional engineer-of-record registered in Alaska, that ensures the grade of the Prudhoe Bay Treatment Plant site would be maintained to prevent flooding throughout the life of the facility considering settlement, subsidence, thermocycling, and sea level rise. (*section 4.18.9*)

34. **Prior to construction of final design**, AGDC shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record registered in Alaska, related to the LNG storage tank and foundation detailed design documents, including but not limited to:

a. LNG storage tank base concrete slabs calculations and drawings;

b. LNG storage tank seismic isolator concrete pedestal calculations and drawings; and

c. LNG storage tank foundation concrete slabs calculations and drawings.

AGDC shall request written authorization from the Director of the OEP or the Director's designee, **before** proceeding with construction of final design and **until** the Director of the OEP, or designee, provides a notice to proceed. (*section 4.18.9*)

35. **Prior to construction of final design**, AGDC shall file with the Secretary documentation that confirms the various tidal levels at the product loading facility do not exceed transfer arm safe operating envelopes or otherwise

demonstrate provisions would be in place to prevent disconnection from the transfer arms during loading operations. (*section 4.18.9*)

36. **Prior to construction of final design,** AGDC shall file with the Secretary an analysis stamped and sealed by a professional engineer in the State of Alaska that demonstrates the product loading facility can withstand the impact from sea ice that historically occurs at the Nikiski site location and that the product loading facility structural load conditions consider sea ice and ice buildup. The basis of design for the loads induced by sea ice shall be filed with the Secretary for the review and written approval by the Director of the OEP, or the Director's designee. (*section 4.18.9*)

Conditions 36 through 160 shall apply to both the Prudhoe Bay Treatment Plant and Liquefaction Facilities, unless otherwise specified. Information pertaining to these specific conditions shall be filed with the Secretary, for review and written approval by the Director of the OEP, or the Director's designee, within the timeframe indicated by each condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 833 (Docket No. RM16-15-000), including security information, shall be submitted as Critical Energy Infrastructure Information pursuant to 18 CFR 388.113. *See* Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information, Order No. 833, 81 Fed. Reg. 93,732 (December 21, 2016), FERC Stats. & Regs. 31,389 (2016). Information pertaining to items such as off-site emergency response, procedures for public notification and evacuation, and construction and operating reporting requirements would be subject to public disclosure. All information shall be filed a minimum of 30 days before approval to proceed is requested.

37. **Prior to initial site preparation**, AGDC shall file an overall Project schedule, which includes the proposed stages of the commissioning plan. *(section 4.18.9)*

38. **Prior to initial site preparation**, AGDC shall file procedures for controlling access during construction. *(section 4.18.9)*

39. **Prior to initial site preparation**, AGDC shall file quality assurance and quality control procedures for construction activities. *(section 4.18.9)*

40. **Prior to initial site preparation***,* AGDC shall file a site-specific geotechnical investigation to ensure proper foundation design of the Prudhoe Bay Treatment Plant. The geotechnical investigation shall include a location plan that demonstrates the soil conditions are suitable or could be made suitable for all major foundations and evaluate local geological conditions under the proposed foundations, including the susceptibility to frost heave, thermokarsting,

subsidence, load-bearing settlement, and concrete material degradation that are projected to occur over the life of the facilities. Also, the soil PH, chloride ion concentration, sulfate ion concentration, and electrical resistivity testing shall be taken into account as part of the site-specific geotechnical investigation. In addition, the geotechnical investigation must demonstrate that the local conditions and those contained in the Alaska Stand Alone Pipeline report supporting its foundation recommendations are sufficiently analogous. *(section 4.18.9)*

41. **Prior to construction of final design**, AGDC shall file a site-specific analysis for coastal erosion and propose a prevention and mitigation plan. *(section 4.18.9)*

42. **Prior to initial site preparation**, AGDC shall file a response plan for a significant snow event or provide calculations that prove the current support structures and equipment will be able to support snow loads. *(section 4.18.9)*

43. **Prior to initial site preparation**, AGDC shall file the updated freeboard height and sloshing wave height design calculation to comply with code requirements, including but not limited to ASCE 7-05, API 620, API 625, API 650, ACI 350 and ACI 376. *(section 4.18.9)*

44. **Prior to initial site preparation**, AGDC shall file the updated reserve capacity test report to determine the vertical load, shear load, and uplift displacement capacities of the triple pendulum seismic isolator type bearing. The test report shall include an analysis for maximum and minimum design liquid levels of the LNG tanks, and the displacement during the empty tank condition. In addition, a separate analysis for variations of design stiffness, minimum values of friction and other properties as required by sections 17.2 and 17.5 of ASCE 7-05 shall be performed. *(section 4.18.9)*

45. **Prior to initial site preparation,** AGDC shall file its design wind speed criteria for all Prudhoe Bay Treatment Plant facilities to be designed to withstand wind speeds commensurate with the risk and reliability in accordance with ASCE 7-16 or equivalent. *(section 4.18.9)*

46. **Prior to initial site preparation**, AGDC shall file calculations demonstrating the loads on buried pipelines and utilities at temporary crossings will be adequately distributed. The analysis shall be based on API RP 1102 or other approved methodology. *(section 4.18.9)*

47. **Prior to initial site preparation,** AGDC shall develop an Emergency Response Plan (ERP) (including evacuation), and coordinate procedures, as applicable,

with the Coast Guard; state, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal agencies. This plan shall include at a minimum:

a. designated contacts with state and local emergency response agencies;

b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;

c. procedures for notifying residents and recreational users within areas of potential hazard;

d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;

e. locations of permanent sirens and other warning devices; and

f. an "emergency coordinator" on each LNG marine vessel to activate sirens and other warning devices.

AGDC shall notify FERC staff of all planning meetings in advance and shall report progress on the development of its ERP **at 3-month intervals**. *(section 4.18.9)*

48. **Prior to initial site preparation**, AGDC shall file a Cost-Sharing Plan identifying the mechanisms for funding all specific security/emergency management costs that would be imposed on state and local agencies. This comprehensive plan shall include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. AGDC shall notify FERC staff of all planning meetings in advance and shall report progress on the development of its Cost Sharing Plan at **3-month intervals**. *(section 4.18.9)*

49. **Prior to initial site preparation**, AGDC shall provide validation or verification for the modeling assumptions and methods used for the vapor dispersion and overpressure modeling for the high pressure CO_2/H_2S and natural gas pipe systems at the Prudhoe Bay Treatment Plant, and provide revised modeling to account for any changes made to the assumptions. The results of this modeling shall be used to inform the ERPs. (*section 4.18.9*)

50. **Prior to initial site preparation**, AGDC shall demonstrate that ERPs include processes and procedures that ensure the plant will be placed in a safe shut down

prior to an evacuation of staff from the central control building in the event of a pipeline incident, including an incident originating from the relocated Hilcorp pipeline, which could affect the Liquefaction Facilities' central control building. *(section 4.18.9)*

51. **Prior to initial site preparation**, AGDC shall demonstrate that ERPs for potential large pipeline ruptures at the Prudhoe Bay Treatment Plant have been coordinated with the adjacent Prudhoe Bay Unit Central Gas Facility plant and include consideration of impacts on the Prudhoe Bay Treatment Plant operator camp site. *(section 4.18.9)*

52. **Prior to construction of final design**, AGDC shall file lighting drawings. The lighting drawings shall show the location, elevation, type of light fixture, and lux levels of the lighting system and shall illustrate adequate coverage, in accordance with federal regulations (e.g., 49 CFR 193, 33 CFR 127, 33 CFR 105, 29 CFR 1910, 29 CFR 1915, and 29 CFR 1926) and API 540 or equivalent, of the perimeter of the facility and along paths/roads of access and egress. *(section 4.18.9)*

53. **Prior to construction of final design**, AGDC shall file security camera and intrusion detection drawings. The security camera drawings shall show the locations, areas covered, and features of each camera (e.g., fixed, tilt/pan/zoom, motion detection alerts, low light, and mounting height) to verify coverage of the entire perimeter with redundancies and cameras interior to the facility to enable rapid and reliable monitoring of the facility. The intrusion detection drawings shall show or note the location of the intrusion detection to verify coverage of the entire perimeter of the facility. *(section 4.18.9)*

54. **Prior to construction of final design**, AGDC shall file drawings of the security fence at the Liquefaction Facilities. The fencing drawings shall provide details of fencing (e.g., dimensions and gauge of fence meshes, posts, and barbed or razor wire) that demonstrate it will restrict and deter access around the entire facility and has a 10-foot clearance from exterior features (e.g., power lines and trees) and from interior features (e.g., piping, equipment, and buildings). *(section 4.18.9)*

55. **Prior to construction of final design**, AGDC shall file specifications, drawings, and details of crash rated vehicle barriers at each facility entrance for access control that can mitigate accidental and intentional vehicle impacts. *(section 4.18.9)*

56. **Prior to construction of final design**, AGDC shall file change logs that list and explain any changes made from the front end engineering design provided in

AGDC's application and filings. A list of all changes with an explanation for the design alteration shall be provided, and all changes shall be clearly indicated on all diagrams and drawings. *(section 4.18.9)*

57. **Prior to construction of final design,** AGDC shall file information/revisions pertaining to its responses to items 55, 58, 70, 71, 73, and 75 of the July 7, 2017 information request; responses to items 8, 14, 16, 19, and 21 of the December 26, 2018 information request; responses to items 2 and 5 of the December 26, 2018 (non-public enclosure); responses to items 3, 11, 17, 18, 21, 22, and 23 of the January 15, 2019 information request; and responses to items 4, 5, 14-17, 20–22, 24, 27, 29, 32–34, 42, 46, and 57 of the September 17, 2019 information request, which indicated features to be included or considered in the final design of the Prudhoe Bay Treatment Plant. *(section 4.18.9)*

58. **Prior to construction of final design**, AGDC shall file information/revisions pertaining to its responses to items 2, 3, 5, 7, 8, 11, 24, 28, 29, 31, 34, 38, 46, 47, and 51 of the July 7, 2017 information request; responses to items 32, 34, 35, 37, 41, 42, 46, 54–61, 66, 69–72, 74, and 75 of the December 26, 2018 information request; responses to items 8, 9, 10, and 13–15 of the December 26, 2018 information request (non-public enclosure); responses to items 56, 60, 66, 70–73, 75–81, and 83 of the January 15, 2019 information request; responses to items 63, 71, 74, 93b, and 97 of the September 17, 2019 information request; and responses to items 3 and 9 of the November 22, 2019 information request, which indicated features to be included or considered in the final design of the Liquefaction Facilities. *(section 4.18.9)*

59. **Prior to construction of final design**, AGDC shall file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems. *(section 4.18.9)*

60. **Prior to construction of final design**, AGDC shall file documentation that demonstrates the multi-use truck unloading/loading facilities at the Prudhoe Bay Treatment Plant and Liquefaction Facilities incorporate safety design features including but not limited to process control and monitoring instrumentation including alarm and automatic shutdown capabilities; configuration of transfer valves, equipment, and hazard mitigation equipment to be activated remotely; unique hose couplings and fill line connections for each type of hazardous fluid; and pipe marking and identification of transfer equipment. *(section 4.18.9)*

61. **Prior to construction of final design,** AGDC shall file the updated LNG tank design that incorporates AGDC's proposed top and bottom filling capabilities in order to mitigate LNG tank stratification and rollover. Also, AGDC shall file procedures to mitigate stratification and potential rollover based on differences in

transferring or loading LNG with different compositions and the time it takes to detect stratification and induce sufficient mixing of the LNG storage tank contents based on the flow rate and storage volume compared to the time it takes for the detected stratification to develop into a potential rollover condition. *(section 4.18.9)*

62. **Prior to construction of final design**, AGDC shall file three-dimensional plant drawings to confirm plant layout for maintenance, access, egress, and congestion. *(section 4.18.9)*

63. **Prior to construction of final design**, AGDC shall file an up-to-date equipment list, process and mechanical data sheets, and specifications. The specifications shall include:

    a. building specifications (e.g., control buildings, electrical buildings, compressor buildings, storage buildings, pressurized buildings, ventilated buildings, and blast resistant buildings);

    b. mechanical specifications (e.g., piping, valve, insulation, rotating equipment, heat exchanger, storage tank and vessel, and other specialized equipment);

    c. electrical and instrumentation specifications (e.g., power system, control system, safety instrument system [SIS], cable, and other electrical and instrumentation); and

    d. security and fire safety specifications (e.g., security, passive protection, hazard detection, hazard control, and firewater). *(section 4.18.9)*

64. **Prior to construction of final design**, AGDC shall file a summary of all applicable codes and standards and the final specification document number(s) where they are referenced. *(section 4.18.9)*

65. **Prior to construction of final design**, AGDC shall file a complete LNG storage tank specification and design drawings. The specification shall define the battery limits (i.e., engineering design, structural design, supports, piping components, piping connections, electrical power, control, and utilities) of the LNG storage tank. *(section 4.18.9)*

66. **Prior to construction of final design**, AGDC shall file drawings of the storage tank piping support structure and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances. *(section 4.18.9)*

67. **Prior to construction of final design,** AGDC shall file up-to-date process flow diagrams and piping and instrument diagrams (P&IDs), including vendor P&IDs. The process flow diagrams shall include heat and material balances. The P&IDs shall include the following information:

a. equipment tag number, name, size, duty, capacity, and design conditions;
b. equipment insulation type and thickness;
c. storage tank pipe penetration size and nozzle schedule;
d. valve high pressure side and internal and external vent locations;
e. piping with line number, piping class specification, size, and insulation type and thickness;
f. piping specification breaks and insulation limits;
g. all control and manual valves numbered;
h. relief valves with size and set points; and
i. drawing revision number and date. *(section 4.18.9)*

68. **Prior to construction of final design**, AGDC shall file P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect subsequently constructed facilities with the operational facilities. *(section 4.18.9)*

69. **Prior to construction of final design**, AGDC shall file a car seal philosophy and a list of all car-sealed and locked valves consistent with the P&IDs. *(section 4.18.9)*

70. **Prior to construction of final design**, AGDC shall file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (i.e., temperature, pressures, flows, and compositions). *(section 4.18.9)*

71. **Prior to construction of final design**, AGDC shall include a check valve or other means in the sour gas inlet piping to the Acid Gas Removal Unit absorber to prevent backflow into the inlet piping. *(section 4.18.9)*

72. **Prior to construction of final design**, AGDC shall include LNG storage tank fill flow measurement with high flow alarm. *(section 4.18.9)*

73. **Prior to construction of final design**, AGDC shall include boil-off-gas flow measurement from each LNG storage tank. *(section 4.18.9)*

74. **Prior to construction of final design**, AGDC shall evaluate and demonstrate the design pressure of the Process Heat Medium Expansion Drum and associated

relief valves is consistent with the heating medium circulation system. *(section 4.18.9)*

75. **Prior to construction of final design**, AGDC shall include layout and design specifications of the pig trap, inlet separation and liquid disposal, inlet/send-out meter station, and pressure control. *(section 4.18.9)*

76. **Prior to construction of final design**, AGDC shall file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown (ESD) system for review and written approval. The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and set points. *(section 4.18.9)*

77. **Prior to construction of final design**, AGDC shall specify that all ESD valves are to be equipped with open and closed position switches connected to the Distributed Control System (DCS) / Safety Instrumented System (SIS). *(section 4.18.9)*

78. **Prior to construction of final design**, AGDC shall file an evaluation of ESD valve closure times. The evaluation shall account for the time to detect an upset or hazardous condition, notify plant personnel, and close the ESD valve. *(section 4.18.9)*

79. **Prior to construction of final design**, AGDC shall file an evaluation of dynamic pressure surge effects from valve opening and closure times and pump startup and shutdown operations. *(section 4.18.9)*

80. **Prior to construction of final design**, AGDC shall file a hazard and operability review (HAZOP) of the final design P&IDs, a list of the resulting recommendations, and action taken on the recommendations. The issued for construction P&IDs shall incorporate the HAZOP recommendations and justification shall be provided for any recommendations that are not implemented. *(section 4.18.9)*

81. **Prior to construction of final design**, AGDC shall file specifications that demonstrate the materials of construction have minimum design metal temperatures (MDMT) that can withstand the minimum expected temperature at the North Slope or that AGDC demonstrates that equipment and piping will be fully depressurized in the event the ambient temperature becomes less than the MDMT with sufficient reliability through SIS or through written procedures. *(section 4.18.9)*

82. **Prior to construction of final design**, AGDC shall demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators. *(section 4.18.9)*

83. **Prior to construction of final design**, AGDC shall file the sizing basis and capacity for the final design of the flares and/or vent stacks as well as the pressure and vacuum relief valves for major process equipment, vessels, and storage tanks. *(section 4.18.9)*

84. **Prior to construction of final design**, AGDC shall file an updated fire protection evaluation of the proposed facilities. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations shall be filed. The evaluation shall justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, ESD and depressurizing systems, firewater, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001). This evaluation shall include justification for blast resistant walls or buildings at the Prudhoe Bay Treatment Plant. The justification for the flammable and combustible gas detection and flame and heat detection shall be in accordance with ISA 84.00.07 or equivalent methodologies that will demonstrate 90 percent or more of releases (unignited and ignited) that could result in an off-site or cascading impact would be detected by two or more detectors and result in isolation and de-inventory within 10 minutes, or less for impoundments that are not sized for 10 minute releases and de-inventory. The analysis shall revise the hazard detection coverage, including, but not limited to, the Prudhoe Bay Treatment Plant's outside areas, or adequately demonstrate that failure to detect releases due to lack of hazard detection coverage will not result in direct or indirect offsite impacts, including projectiles from potential boiling liquid expanding vapor explosion resulting from undetected fire events. The analysis shall take into account the set points, voting logic, wind speeds, and wind directions. The justification for firewater shall provide evaluation of the total area that may experience firewater demand due to each governing scenario; calculations for all firewater demands (including firewater coverage on the LNG storage tanks) based on design densities, surface area, and throw distance; and specifications for the corresponding hydrants and monitors needed to reach and cool equipment. *(section 4.18.9)*

85. **Prior to construction of final design**, AGDC shall file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, and capacity calculations considering any foundations and equipment within impoundments, as well as the sizing and design of the down-comer that will

transfer spills from the tank top to the ground-level impoundment system. The spill containment drawings shall show containment for all components that could contain hazardous liquids, including all liquids handled above their flashpoint and those with toxic or asphyxiant vapor hazards, from the largest flow from a single line for 10 minutes, including de-inventory and specifying a reliability equivalent to SIL 2 or higher for any pump interlock systems, or the maximum liquid from the largest vessel (or total of impounded vessels), or otherwise demonstrate that providing spill containment will not significantly reduce the vapor dispersion or radiant heat consequences of a spill, including for any tank top LNG releases up to a full guillotine that would not be captured to the tank area impoundment. Spill containment systems shall be constructed of materials that can withstand the liquid hazards. In addition, the rainout calculations for a liquid nitrogen vessel failure shall be provided with validation, or liquid nitrogen containment shall be provided. Also, AGDC shall provide details of collection for spills occurring at the onshore pipe- in-pipe ESD valve and over road crossings; details of hazardous liquid trenches crossing storm water trenches; containment for the condensate, slop oil, and diesel piping in the area near their storage tank impoundments at the Liquefaction Facilities; and details on whether the miscellaneous hydrocarbon fluid at the Prudhoe Bay Treatment Plant site will be handled above its flash point, as well as confirming that the most significant hazardous compositions in knockout drums have been considered. *(section 4.18.9)*

86. **Prior to construction of final design**, AGDC shall file an analysis and/or tests that demonstrate either the pipe-in-pipe system at the Liquefaction Facilities will maintain integrity and not initiate and propagate cracks when subjected to sudden cryogenic temperatures and forces from the full range of jetting release sizes, or alternatively, revise the spill containment design for this piping to include a conventional trough and impoundment system. *(section 4.18.9)*

87. **Prior to construction of final design**, AGDC shall file the following for the final design of the pipe-in-pipe systems at the Liquefaction Facilities, including:

    a. the detailed design and a plot plan layout of the pipe-in-pipe system, including identification of all conventional process lines extending from or attached to the pipe-in-pipe, as well as the locations of any reliefs, instrumentation or other connections along the inner or outer pipes;

    b. an assessment of the vapor production and vapor handling capacities within the annular space during a full inner pipe rupture or smaller release into the outer pipe;

c. stress analysis for the pipe-in-pipe systems, including at bulkheads and including the differential stresses between the inner pipe and outer pipe for a full inner pipe rupture, or any smaller release, at any location along the system;

d. leak testing details and pressures for the outer pipe;

e. details of the maintenance procedures that will be followed over the life of the facility to determine that the outer pipe will be continuing to adequately serve as spill containment;

f. plans for purging or draining LNG from the outer pipe; and

g. details of any features that will protect against external common cause failures of the inner and outer pipes, including heavy equipment accidents. *(section 4.18.9)*

88. **Prior to construction of final design,** AGDC shall demonstrate that the design of the marine impoundment system will capture liquid rainout resulting from jetting releases up to a full guillotine rupture of a dock transfer line, which could cause impacts on dock or trestle supports, nearby public, berthed LNG marine vessels and tugs, or other cascading impacts. *(section 4.18.9)*

89. **Prior to construction of final design**, AGDC shall provide details of how LNG spills at the dock will be fully contained in impoundment areas without resulting in cascading failures to equipment and structural supports, including how LNG will be collected on the trestle containment system without spreading over the dock surface and ensuring the structural supports will accommodate the liquid weight. *(section 4.18.9)*

90. **Prior to construction of final design**, AGDC shall provide the following on the water, snow, and ice handling systems for impoundments:

a. water removal pumps for locally-curbed hazardous liquid impoundments at the Liquefaction Facilities, such as those around knockout drums; and

b. details on how hardened snow will be assured to not inhibit the spill flow path (e.g., maintenance plans and/or details of snowmelt methods), including in spill collection areas and trenches leading to impoundments, and be assured to not reduce the volume of any part the impoundment system beyond the extra height allowed in the impoundment system specifically for snow accumulation. *(section 4.18.9)*

91. **Prior to construction of final design**, AGDC shall file detailed calculations to confirm that the final fire water volumes will be accounted for when evaluating the capacity of the impoundment system during a spill and fire scenario. *(section 4.18.9)*

92. **Prior to construction of final design**, AGDC shall analyze the potential for the overpressures from vapor cloud ignition underneath the module platforms to cause movement of or damage to the platforms that could affect the high pressure equipment above them, such as the treated gas chillers and associated piping as well as CO_2/H_2S piping, and provide any measures needed to prevent significant cascading damage and safety impacts. *(section 4.18.9)*

93. **Prior to construction of final design**, AGDC shall file details of the mitigation measures that will prevent flammable vapors from entering the semi-confined spaces underneath the LNG storage tanks, including details of the measures that will prevent temperatures in this space that could impair the functionality of the seismic isolators or cause frost heave. *(section 4.18.9)*

94. **Prior to construction of final design**, AGDC shall file electrical area classification drawings including cross-sectional drawings. The drawings shall demonstrate compliance with NFPA 59A, NFPA 70, NFPA 497, and API RP 500, or equivalents. In addition, the drawings shall include revisions to the electrical area classification design or provide technical justification that supports the electrical area classification of the following areas using most applicable API RP 500 figures (e.g., figures 20 and 21) or hazard modeling of various release rates from equivalent hole sizes and wind speeds (*see* NFPA 497 release rate of 1 pound/minute) for the spill trench that will serve the portion of the LNG liquefaction rundown pipe rack located west of the air fin coolers, which would contain process piping, the spill containment systems for both marine berth areas, and the LNG marine transfer lines and marine trestle area. *(section 4.18.9)*

95. **Prior to construction of final design**, AGDC shall file design details and specifications of the local electrical rooms located within the Prudhoe Bay Treatment Plant's process modules including, but not limited to, the pressurization system, HVAC air intake system, and any openings such as personnel entry door(s), electrical cable entries, and air conditioning unit(s). The design details and specifications shall demonstrate compliance with NFPA 59A, NFPA 70, NFPA 496, NFPA 497, and API RP 500, or equivalents. *(section 4.18.9)*

96. **Prior to construction of final design**, AGDC shall file drawings and details of how process seals or isolations installed at the interface between a flammable

fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001). *(section 4.18.9)*

97. **Prior to construction of final design**, AGDC shall file details of an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap shall vent to a safe location and be equipped with a leak detection device that shall continuously monitor for the presence of a flammable fluid, alarm the hazardous condition, and shut down the appropriate systems. *(section 4.18.9)*

98. **Prior to construction of final design**, AGDC shall file a drawing showing the location of the ESD buttons. ESD buttons shall be easily accessible, conspicuously labeled, and located in an area that will be accessible during an emergency. *(section 4.18.9)*

99. **Prior to construction of final design**, AGDC shall file complete drawings and a list of the hazard detection equipment. The drawings shall clearly show the location and elevation of all detection equipment. The list shall include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment. *(section 4.18.9)*

100. **Prior to construction of final design,** AGDC shall file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of the hazard detectors when determining the lower flammable limit set points for methane, propane, ethane, and condensate. *(section 4.18.9)*

101. **Prior to construction of final design**, AGDC shall file a list of alarm and shutdown set points for all hazard detectors that accounts for the calibration gas of hazard detectors when determining the set points for toxic components such as natural gas liquids and H_2S. *(section 4.18.9)*

102. **Prior to construction of final design**, AGDC shall file a technical review of facility design that:

    a. identifies all combustion/ventilation air intake equipment and the elevations and distances to any possible flammable gas or toxic release; and

    b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices will isolate or shutdown any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency. *(section 4.18.9)*

103. **Prior to construction of final design**, AGDC shall file analysis of the buildings containing hazardous fluids and the ventilation calculations that limit concentrations below the lower flammability limits (LFLs) (e.g., 25-percent LFL), including an analysis of off gassing of hydrogen in battery rooms, and shall also provide hydrogen detectors that alarm (e.g., 20- to 25-percent LFL) and initiate mitigative actions (e.g., 40- to 50-percent LFL) in accordance with NFPA 59A and NFPA 70, or equivalents. *(section 4.18.9)*

104. **Prior to construction of final design**, AGDC shall provide low oxygen detectors to notify operators of liquid nitrogen releases at the Liquefaction Facilities. *(section 4.18.9)*

105. **Prior to construction of final design**, AGDC shall provide an evaluation of the normal module air changes within buildings at the Prudhoe Bay Treatment Plant and reliability of the ventilation system to determine whether oxygen detectors are needed as an additional layer of protection to notify operators of a potential nitrogen release and ensure safe entry into a module/building. The evaluation shall also address whether there will be alarms and notifications in the event ventilation equipment is not operating or functioning as designed. *(section 4.18.9)*

106. **Prior to construction of final design**, AGDC shall file an evaluation of the voting logic and voting degradation for hazard detectors. *(section 4.18.9)*

107. **Prior to construction of final design**, AGDC shall file facility plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Plan drawings shall clearly show the location and elevation by tag number of all fixed dry chemical systems in accordance with NFPA 17, wheeled and handheld extinguishers location travel distances are along normal paths of access and egress in accordance with NFPA 10. The list shall include the equipment tag number, type, capacity, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units. *(section 4.18.9)*

108. **Prior to construction of final design**, AGDC shall file a design that includes clean agent systems in the instrumentation and electrical equipment buildings that serve safety and security systems. *(section 4.18.9)*

109. **Prior to construction of final design**, AGDC shall file facility plan drawings showing the proposed location of the firewater and any foam systems. Plan

drawings shall clearly show the location of firewater and foam piping, post indicator valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, foam system, water-mist system, and sprinkler. The drawings shall also include piping and instrumentation diagrams of the firewater and foam systems. The firewater coverage drawings shall illustrate firewater coverage by two or more hydrants or monitors accounting for obstructions (or deluge systems) for all areas that contain flammable or combustible fluids. *(section 4.18.9)*

110. **Prior to construction of final design**, AGDC shall specify remotely operated or automatic firewater monitors at the Liquefaction Facilities in areas inaccessible or difficult to access in the event of an emergency. *(section 4.18.9)*

111. **Prior to construction of final design**, AGDC shall demonstrate that the firewater tank will be in compliance with NFPA 22 or an equivalent or better level of safety. *(section 4.18.9)*

112. **Prior to construction of final design**, AGDC shall include or demonstrate the firewater storage volume for its facilities has minimum reserved capacity for its most demanding firewater scenario plus 1,000 gpm for no less than 2 hours. *(section 4.18.9)*

113. **Prior to construction of final design**, AGDC shall specify that firewater pump shelters are designed to remove the largest firewater pump or other component for maintenance with an overhead or external crane. *(section 4.18.9)*

114. **Prior to construction of final design**, due to the absence of firewater monitor coverage, AGDC shall demonstrate that the potential for pool and jet fires to cause cascading hazards in any area of the Prudhoe Bay Treatment Plant will be effectively mitigated by systems with a reliability equivalent to Safety Integrity Level 2 or higher. *(section 4.18.9)*

115. **Prior to construction of final design**, AGDC shall file drawings and specifications for the passive protection systems at the Prudhoe Bay Treatment Plant and Liquefaction Facilities to protect piping, equipment, and supports from cold temperature releases, including for liquids conveyed indoors during winter start-ups at design ambient temperatures at the Prudhoe Bay Treatment Plant. *(section 4.18.9)*

116. **Prior to construction of final design**, AGDC shall file calculations or test results for the structural passive protection systems at the Prudhoe Bay Treatment Plant and Liquefaction Facilities to demonstrate that equipment and

supports are protected from low temperature releases that are below the MDMT of equipment and supports. *(section 4.18.9)*

117. **Prior to construction of final design**, AGDC shall file drawings and specifications for the structural passive protection systems at the Prudhoe Bay Treatment Plant and Liquefaction Facilities to demonstrate the equipment and supports are protected from pool and jet fires, including that the fireproofing material will remain effective after potential exposure to the cold temperature of pooling, jetting, or splashing liquids. *(section 4.18.9)*

118. **Prior to construction of final design**, AGDC shall file a detailed quantitative analysis to demonstrate that adequate mitigation will be provided for each pressure vessel that could fail within the 4,000 BTU/ft^2-hr zone from a pool or jet fire; each critical structural component (including the LNG marine vessel and outer pipe of the pipe-in-pipe containment system) and emergency equipment item that could fail within the 4,900 BTU/ft^2-hr zone from a pool or jet fire; and each occupied building that could expose unprotected personnel within the 1,600 BTU/ft^2-hr zone from a pool or jet fire. Trucks at truck transfer stations shall be included in the analysis of potential pressure vessel failures. A combination of passive and active protection for pool fires and passive and/or active protection for jet fires shall be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation shall be supported by calculations or test results for the thickness limiting temperature rise over the fire duration, and active mitigation shall be supported by reliability information by calculations or test results, such as demonstrating that flow rates and durations of any cooling water will mitigate the heat absorbed by the component. The total firewater demand shall account for all components that could fail due to a pool or jet fire. *(section 4.18.9)*

119. **Prior to construction of final design**, AGDC shall provide an analysis demonstrating occupied buildings at the Liquefaction Facilities will be able to withstand radiant heats from pool fires, as well as jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC shall file an analysis demonstrating the occupied buildings at the Liquefaction Facilities have been relocated or provided with passive and active measures that will prevent impacts. *(section 4.18.9)*

120. **Prior to construction of final design**, AGDC shall file an analysis demonstrating safety related equipment (e.g., firewater pump buildings, control buildings, and emergency generators) at the Liquefaction Facilities will be able to withstand radiant heats from pool fires, as well as jet fires and overpressures

and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC shall file an analysis demonstrating the safety related equipment at the Liquefaction Facilities have been relocated or provided with passive and active measures that will prevent impacts. *(section 4.18.9)*

121. **Prior to construction of final design**, AGDC shall file an analysis demonstrating the refrigerant storage vessels at the Liquefaction Facilities will be able to withstand radiant heats from pool fires, as well as jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC shall file an analysis demonstrating the refrigerant storage vessels at the Liquefaction Facilities have been relocated or provided with passive and active measures that will prevent impacts. *(section 4.18.9)*

122. **Prior to construction of final design**, AGDC shall file specifications and drawings demonstrating how cascading damage of transformers will be prevented (e.g., firewalls or spacing) in accordance with NFPA 850 or equivalent. *(section 4.18.9)*

123. **Prior to construction of final design**, AGDC shall file an evaluation of the final design of grated module platforms at the Liquefaction Facilities that demonstrates a vapor cloud explosion of significant magnitude will not develop from a design spill such that it results in cascading damage that could have impacts offsite. *(section 4.18.9)*

124. **Prior to construction of final design**, AGDC shall file an analysis demonstrating the LNG storage tank outer walls can withstand the overpressures generated from ignition of vapor clouds from design spills in adjacent plant areas. *(section 4.18.9)*

125. **Prior to construction of final design**, AGDC shall file a projectile analysis that demonstrates each LNG storage tank can withstand projectiles from explosions and high winds. The analysis shall detail and justify the projectile speeds and characteristics and method used to determine penetration or perforation depths. *(section 4.18.9)*

126. **Prior to construction of final design**, AGDC shall file drawings of internal road vehicle protections, such as guard rails, barriers, and bollards to protect all equipment containing hazardous fluids or that are safety related (e.g., hydrants

and monitors) to ensure that they are located away from roadway or protected from inadvertent damage from vehicles. *(section 4.18.9)*

127. **Prior to construction of final design**, AGDC shall file documentation demonstrating the Seismic Isolation system for the LNG tanks complies with the design, analysis, and testing requirements of Chapter 17 of ASCE 7-05, or equivalent. The Peer Review of the design shall be performed as required by Chapter 17 of ASCE 7-05, or equivalent. *(section 4.18.9)*

128. **Prior to construction of final design**, AGDC shall file an analysis of the structural integrity of the outer containment, tank foundation concrete slabs, tank base concrete slabs, and seismic isolator concrete pedestals, demonstrating they are designed to withstand all loads and combinations that comply with code requirements, including but not limited to ASCE 7-05, ACI 318, ACI 350, ACI 376, API 620, API 625 and API 650, or equivalents. *(section 4.18.9)*

129. **Prior to construction of final design**, AGDC shall file the finite element analysis (FEA) modeling with the inputs and outputs reports for tanks design, base concrete slabs and foundation concrete slabs design, including details of splicing of precast concrete LNG tank panels, connections to be used between the outer LNG walls and the vapor barrier dome and demonstrate the results of the FEA modeling are within design limits. *(section 4.18.9)*

130. **Prior to construction of final design**, AGDC shall file a detailed analysis and any associated drawings that demonstrate seismic sliding and overturning resistance of the LNG tank's inner tank would not result in failure of the tank. *(section 4.18.9)*

131. **Prior to construction of final design**, AGDC shall file design calculations to confirm the combination of overturning moment and seismic vertical acceleration that induce any uplift and shear of the external wall can be handled with the seismic tendons in combination with shear key. *(section 4.18.9)*

132. **Prior to construction of final design**, AGDC shall file the non-linear dynamic analysis (modal response-spectrum analysis, response-history analysis, linear time-history analysis, and nonlinear time-history analysis) for the LNG tank and isolation system that would simultaneously include the time history, vertical component of motion envelope, and the site-specific vertical design response spectra. The analysis shall also account for horizontal components rotated so that one of the components for each set of motions is the maximum component of response at the isolated period of the tank. The Peer Review of the design shall be performed as required by Chapter 17 of ASCE 7-05 or equivalent to

demonstrate the LNG tank and isolation system is designed to withstand ground motion without loss of structural or functional integrity. *(section 4.18.9)*

133. **Prior to construction of final design,** AGDC shall file design details of the seismic monitoring system for the proposed Liquefaction Facilities with specific peak ground motion data and include at least one free-field triaxial accelerometer at the site, as well as additional instruments on each tank and its foundation. *(section 4.18.9)*

134. **Prior to construction of final design**, AGDC shall file a detailed analysis and any associated drawings of the omega joints that will be used between the bottom LNG tank plate and the bottom of the outer tank wall to demonstrate the final tank design incorporates wall-to-base connections that are consistent with criteria specified in ACI 376 or equivalent. *(section 4.18.9)*

135. **Prior to construction of final design**, AGDC shall file a detailed analysis and any associated drawings detailing the LNG tank secondary bottom design that demonstrates protection of the LNG tank slab and seismic isolators from any cryogenic temperatures it will be exposed to during a spill. *(section 4.18.9)*

136. **Prior to construction of final design**, AGDC shall file the cryogenic protection plan for all LNG tank foundation concrete slabs and triple pendulum seismic isolator concrete pedestal supports during spill condition. *(section 4.18.9)*

137. **Prior to construction of final design**, AGDC shall file the design analysis to determine the precast panel outer wall behavior for operating and spill conditions and to ensure panel and joint leak tightness. *(section 4.18.9)*

138. **Prior to construction of final design,** AGDC shall file a snow removal plan for critical equipment or provide calculations that prove that support structures and equipment adequately account for snow loads. *(section 4.18.9)*

139. **Prior to construction of final design**, AGDC shall file an analysis indicating areas susceptible to falling ice and snow, and file drawings of structures and coverings that will protect people, piping, and equipment from falling snow and ice. *(section 4.18.9)*

140. **Prior to construction of final design**, AGDC shall file calculations demonstrating the loads induced by vehicles, including cranes and other heavy equipment, associated with operations and maintenance of the Prudhoe Bay Treatment Plant and Liquefaction Facilities that may exceed the design of buried pipelines and utilities (or encasements) at permanent crossings will be adequately

distributed. The analysis shall be based on API RP 1102 or other approved methodology. *(section 4.18.9)*

141. **Prior to commissioning**, AGDC shall file a detailed schedule for commissioning through equipment startup. The schedule shall include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids and during commissioning and startup. AGDC shall file documentation certifying that each of these milestones has been completed **before** authorization to commence the next phase of commissioning and startup will be issued. *(section 4.18.9)*

142. **Prior to commissioning**, AGDC shall file detailed plans and procedures for: testing the integrity of on-site mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service. *(section 4.18.9)*

143. **Prior to commissioning**, AGDC shall file the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3. The procedures shall include a line list of pneumatic and hydrostatic test pressures. *(section 4.18.9)*

144. **Prior to commissioning**, AGDC shall file a plan for clean-out, dry-out, purging, and tightness testing. This plan shall address the requirements of the American Gas Association's Purging Principles and Practice and shall provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing. *(section 4.18.9)*

145. **Prior to commissioning**, AGDC shall file the operation and maintenance procedures and manuals, as well as safety procedures, hot work procedures and permits, abnormal operating conditions reporting procedures, simultaneous operational procedures, and management of change procedures and forms. In addition, AGDC shall include an LNG storage tank stratification monitoring, prevention, and correction procedure to be included as part of the operation and maintenance procedures. *(section 4.18.9)*

146. **Prior to commissioning**, AGDC shall file truck transfer procedures that require facility personnel to verify, through written checklists, ignition sources are eliminated (e.g., no smoking, ground wire, and engine shutoff) within at least 50 feet prior to transfer operations; transfer connections are marked or labeled and match truck contents prior to transfer operations; and truck transfer operations are constantly attended or visually monitored to physically or remotely shut down truck transfer operations. In addition, the procedures shall include

recognition of abnormalities and use of emergency shutoff mechanisms. Operators shall be trained on these procedures and requirements. *(section 4.18.9)*

147. **Prior to commissioning**, AGDC shall tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves. *(section 4.18.9)*

148. **Prior to commissioning**, AGDC shall file a plan to maintain a detailed training log to demonstrate that operating, maintenance, and emergency response staff has completed the required training. In addition, AGDC shall file signed documentation that demonstrates training has been conducted, including ESD and response procedures, prior to the respective operation. *(section 4.18.9)*

149. **Prior to commissioning**, AGDC shall equip the LNG storage tanks and adjacent piping and supports with permanent settlement monitors to allow personnel to observe and record the relative settlement between the LNG storage tank and adjacent piping. The settlement record shall be reported in the semi-annual operational reports. *(section 4.18.9)*

150. **Prior to commissioning,** AGDC shall file settlement results from hydrostatic tests of the LNG storage containers and shall file a plan to periodically verify settlements are as expected and do not exceed applicable criteria in API 620, API 625, API 653, and ACI 376, or equivalents. *(section 4.18.9)*

151. **Prior to introduction of hazardous fluids**, AGDC shall complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS/SIS that demonstrate full functionality and operability of the system. *(section 4.18.9)*

152. **Prior to introduction of hazardous fluids**, AGDC shall develop and implement an alarm management program to reduce alarm complacency and maximize the effectiveness of operator response to alarms. *(section 4.18.9)*

153. **Prior to introduction of hazardous fluids**, AGDC shall complete and document a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s). *(section 4.18.9)*

154. **Prior to introduction of hazardous fluids**, AGDC shall complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review shall include any changes since the last hazard review, operating procedures, and operator

training. A copy of the review with a list of recommendations, and actions taken on each recommendation, shall be filed. *(section 4.18.9)*

155. **Prior to introduction of hazardous fluids**, AGDC shall file finalized ERP(s), including coordination with federal, state, and local agencies and neighboring facilities, such as the Prudhoe Bay Unit Central Gas Facility and other facilities handling hazardous materials, and shall include processes and procedures to be used in the event of an incident at the Prudhoe Bay Treatment Plant, Liquefaction Facilities, and neighboring facilities. *(section 4.18.9)*

156. AGDC shall file a request for written authorization from the Director of the OEP, or the Director's designee, prior to unloading or loading the first LNG commissioning cargo. After production of first LNG, AGDC shall file weekly reports on the commissioning of the proposed systems that detail the progress toward demonstrating the facilities can safely and reliably operate at or near the design production rate. The reports shall include a summary of activities, problems encountered, and remedial actions taken. The weekly reports shall also include the latest commissioning schedule, including projected and actual LNG production by each liquefaction train, LNG storage inventories in each storage tank, and the number of anticipated and actual LNG commissioning cargoes, along with the associated volumes loaded or unloaded. Further, the weekly reports shall include a status and list of all planned and completed safety and reliability tests, work authorizations, and punch list items. Problems of significant magnitude shall be reported to FERC **within 24 hours**. *(section 4.18.9)*

157. **Prior to commencement of service**, AGDC shall notify FERC staff of any proposed revisions to the security plan and physical security of the plant. *(section 4.18.9)*

158. **Prior to commencement of service**, AGDC shall label piping with fluid service and direction of flow in the field, in addition to the pipe labeling requirements of NFPA 59A (2001). *(section 4.18.9)*

159. **Prior to commencement of service**, AGDC shall provide plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring. *(section 4.18.9)*

160. **Prior to commencement of service**, AGDC shall develop procedures for handling off-site contractors, including responsibilities, restrictions, and limitations and for supervision of these contractors by AGDC staff. *(section 4.18.9)*

161. **Prior to commencement of service**, AGDC shall file a request for written authorization from the Director of the OEP, or the Director's designee. Such authorization would only be granted following a determination by the Coast Guard, under its authorities under the Ports and Waterways Safety Act, the Magnuson-Stevens Act, the Marine Transportation Security Act of 2002, and the Security and Accountability For Every Port Act, that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by AGDC or other appropriate parties. *(section 4.18.9)*

In addition, conditions 162 through 165 shall apply throughout the life of the Liquefaction Facilities and Prudhoe Bay Treatment Plant**, unless otherwise specified.**

162. The facility shall be subject to regular FERC staff technical reviews and site inspections on at least an annual basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, AGDC shall respond to a specific information request, including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, shall be submitted. *(section 4.18.9)*

163. Semi-annual operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (e.g., ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to, unloading/loading/shipping problems, potential hazardous conditions from off-site vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the effect on the facility also shall be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled *Significant Plant Modifications Proposed for the Next 12 Months (dates)* shall be included in the semi-annual operational reports. Such information would provide FERC staff with early

notice of anticipated future construction/maintenance at the Prudhoe Bay Treatment Plant and Liquefaction Facilities. *(section 4.18.9)*

164. In the event the temperature of any region of the LNG storage container, including any secondary containment and imbedded pipe supports, becomes less than the minimum specified operating temperature for the material, the Commission shall be notified **within 24 hours** and procedures for corrective action shall be specified. *(section 4.18.9)*

165. Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases; fires; explosions; mechanical failures; unusual over pressurization; and major injuries) and security-related incidents (e.g., attempts to enter site and suspicious activities) shall be reported to FERC staff. In the event that an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made **immediately**, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to FERC staff **within 24 hours**. This notification practice shall be incorporated into the emergency plan. Examples of reportable hazardous fluids-related incidents include:

    a. fire;

    b. explosion;

    c. estimated property damage of $50,000 or more;

    d. death or personal injury necessitating in-patient hospitalization;

    e. release of hazardous fluids for 5 minutes or more;

    f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of a facility that contains, controls, or processes hazardous fluids;

    g. any crack or other material defect that impairs the structural integrity or reliability of a facility that contains, controls, or processes hazardous fluids;

    h. any malfunction or operating error that causes the pressure of a pipeline or facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for facilities) plus the build-up allowed for operation of pressure-limiting or control devices;

i. a leak in a facility that contains or processes hazardous fluids that constitutes an emergency;

j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20-percent reduction in operating pressure or shutdown of operation of a pipeline or a facility that contains or processes hazardous fluids;

l. safety-related incidents from hazardous fluids transportation occurring at or en route to and from the Prudhoe Bay Treatment Plant or Liquefaction Facilities; or

m. an event that is significant in the judgment of the operator and/or management even though it does not meet the above criteria or the guidelines set forth in an LNG terminal's incident management plan.

In the event of an incident, the Director of the OEP, or the Director's designee, has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property, or the environment, including authority to direct the facilities to cease operations. **Following the initial company notification**, FERC staff would determine the need for a separate follow-up report or follow up in the upcoming semi-annual operational report. All company follow-up reports shall include investigation results and recommendations to minimize a reoccurrence of the incident. *(section 4.18.9)*

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Alaska Gasline Development Corporation Docket No. CP17-178-000

(Issued May 21, 2020)

GLICK, Commissioner, *dissenting*:

1. I dissent from today's order because it violates both the Natural Gas Act[1] (NGA) and the National Environmental Policy Act[2] (NEPA). Rather than wrestling with the Alaska LNG Project's[3] significant adverse impacts, today's order makes clear that the Commission will not allow these impacts to get in the way of its outcome-oriented desire to approve the Project.

2. As an initial matter, the Commission once again refuses to consider the consequences its actions have for climate change. Although neither the NGA nor NEPA permit the Commission to assume away the impact that constructing and operating the Project will have on climate change, that is precisely what the Commission is doing here. In today's order authorizing the Project, pursuant to section 3 of the NGA, the Commission continues to treat climate change differently than all other environmental impacts. The Commission steadfastly refuses to assess whether the impact of the Project's greenhouse gas (GHG) emissions on climate change is significant, even though it quantifies the direct GHG emissions caused by the Project's construction and operation.[4] That refusal to assess the significance of the Project's contribution to the

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[1] 15 U.S.C. §§ 717b, 717f (2018).

[2] National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321 *et seq.*

[3] Today's order authorizes the construction and operation of the Alaska LNG Project (Project) pursuant to NGA section 3, 15 U.S.C. § 717b (2018). The Project consists of a gas treatment plant located on Alaska's North Slope; two natural gas pipelines connecting production units to the gas treatment plant as well as an approximately 806.9-mile-long, 42-inch-diameter pipeline (Mainline Pipeline); eight compressor stations along the Mainline Pipeline; and liquefaction facilities on the Kenai Peninsula designed to produce up to 20 million metric tons per annum of LNG for export.

[4] *Alaska Gasline Development Corp.*, 171 FERC ¶ 61,134, at P 214 (2020) (Certificate Order); Alaska LNG Project Final Environmental Impact Statement at § 4.15, Tables 4.15.4-1–4.15.4-5, 4.15.5-1, 4.15.5-10–4.15.5-15, 4.15.5-20 (EIS). *See also*

harm caused by climate change is what allows the Commission to perfunctorily conclude that the environmental impacts associated with the Project are "acceptable"[5] and, as a result, conclude that the Project satisfies the NGA's public interest standard.[6] Claiming that a project's environmental impacts are acceptable while at the same time refusing to assess the significance of the project's impact on the most important environmental issue of our time is not reasoned decisionmaking.

3. Moreover, the Commission's public interest analysis does not adequately wrestle with the Project's adverse environmental impacts. The Commission finds that the Project will have a significant and adverse effect on several endangered species, the Central Artic Herd of caribou, permafrost, forest, and air quality for certain nationally designated areas.[7] Although the Commission discloses these adverse impacts, at no point does it explain how it considered them in making its public interest determination or why it finds that the Project satisfies the public interest standard notwithstanding those substantial impacts. Simply asserting that the Project is not inconsistent with the public interest after dismissively classifying all significant adverse impacts as "acceptable" without explanation is not reasoned decisionmaking.

4. What is more, the Commission plainly lacks the record needed to make the necessary public interest findings. In particular, the Commission has not yet received a final determination from the resource agencies regarding the Project's considerable adverse effects on endangered species. The fact that the Commission believes that it can make a public interest finding without hearing from the experts on endangered species tells you everything you need to know about how seriously it takes those impacts, no matter what the Commission says to the contrary. Actions, after all, speak louder than words.

5. Finally, this Project is unprecedented in both scale and scope, stretching 800 miles across unique and fragile ecosystem of Northern Alaska. Many of the challenges presented by this project are first-of-their-kind and demand in-depth and rigorous examination.[8] Certain environmental impacts in particular are ones which the

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Certificate Order, 171 FERC ¶ 61,134 at PP 211, 213 (providing corrections to the GHG figures in the EIS).

[5] Certificate Order, 171 FERC ¶ 61,134 at P 251.

[6] *Id.*

[7] *See, e.g., id.* P 25; EIS at ES-7 and 5-1.

[8] Certificate Order, 171 FERC ¶ 61,134 at P 9 ("[W]e have never exerted NGA section 3 jurisdiction over a project of this size. However, the scope of these facilities is

Commission, and even industry, has little experience, giving us precious little to go on in assessing the magnitude of the impacts and designing appropriate mitigation.[9] And yet, the Commission is rushing to issue this certificate, while many unknowns still linger.

I. The Commission's Public Interest Determinations Are Not the Product of Reasoned Decisionmaking

6. The NGA's regulation of LNG import and export facilities "implicate[s] a tangled web of regulatory processes" split between the U.S. Department of Energy (DOE) and the Commission.[10] The NGA establishes a general presumption favoring the import and export of LNG unless there is an affirmative finding that the import or export "will not be consistent with the public interest."[11] Section 3 of the NGA provides for two independent public interest determinations: One regarding the import or export of LNG itself and one regarding the facilities used for that import or export.

7. DOE determines whether the import or export of LNG is consistent with the public interest, with transactions among free trade countries legislatively deemed to be "consistent with the public interest."[12] The Commission evaluates whether "an

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a function of the unique nature of Alaska.").

[9] Certificate Order, 171 FERC ¶ 61,134 at PP 64, 71-74 (permafrost), 102-105 (caribou).

[10] *Sierra Club v. FERC*, 827 F.3d 36, 40 (D.C. Cir. 2016) (*Freeport*).

[11] 15 U.S.C. § 717b(a); *see EarthReports, Inc. v. FERC*, 828 F.3d 949, 953 (D.C. Cir. 2016) (citing *W. Va. Pub. Servs. Comm'n v. Dep't of Energy*, 681 F.2d 847, 856 (D.C. Cir. 1982) ("NGA [section] 3, unlike [section] 7, 'sets out a general presumption favoring such authorization.'")). Under section 7 of the NGA, the Commission approves a proposed pipeline if it is shown to be consistent with the public interest, while under section 3, the Commission approves a proposed LNG import or export facility unless it is shown to be inconsistent with the public interest. *Compare* 15 U.S.C. § 717b(a) *with id.* § 717f(a), (e).

[12] 15 U.S.C. § 717b(c). The courts have explained that, because the authority to authorize the LNG exports rests with DOE, NEPA does not require the Commission to consider the upstream or downstream GHG emissions that may be indirect effects of the export itself when determining whether the related LNG export facility satisfies section 3 of the NGA. *See Freeport*, 827 F.3d at 46-47; *see also Sierra Club v. FERC*, 867 F.3d 1357, 1373 (D.C. Cir. 2017) (*Sabal Trail*) (discussing *Freeport*). Nevertheless, NEPA

application for the siting, construction, expansion, or operation of an LNG terminal" is itself consistent with the public interest.[13] Pursuant to that authority, the Commission must approve a proposed LNG facility unless the record shows that the facility would be inconsistent with the public interest.[14] Today's order fails to satisfy that standard in multiple respects.

A. **The Commission's Public Interest Determination Does Not Adequately Consider Climate Change**

8. In making its public interest determination, the Commission examines a proposed facility's impact on the environment and public safety. A facility's impact on climate change is one of the environmental impacts that must be part of a public interest determination under the NGA.[15] Nevertheless, the Commission maintains that it need not consider and ultimately determine whether the Project's contribution to climate change is significant because it lacks a means to do so—or at least so it claims.[16] However, the most troubling part of the Commission's rationale is what comes next. Based on this alleged inability to assess the significance of the Project's impact on climate change, the Commission still concludes that all of the Project's environmental impacts would be "acceptable."[17] Think about that. The Commission is simultaneously stating that it

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requires that the Commission consider the direct GHG emissions associated with a proposed LNG export facility. *See Freeport*, 827 F.3d at 41, 46.

[13] 15 U.S.C. § 717b(e). In 1977, Congress transferred the regulatory functions of NGA section 3 to DOE. DOE, however, subsequently delegated to the Commission authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal, while retaining the authority to determine whether the import or export of LNG to non-free trade countries is in the public interest. *See EarthReports*, 828 F.3d at 952-53.

[14] *See Freeport*, 827 F.3d at 40-41.

[15] *See Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 391 (1959) (holding that the NGA requires the Commission to consider "all factors bearing on the public interest"); *see also Sabal Trail*, 867 F.3d at 1373 (explaining that the Commission must consider a pipeline's direct and indirect GHG emissions because the Commission may "deny a pipeline certificate on the ground that the pipeline would be too harmful to the environment").

[16] Certificate Order, 171 FERC ¶ 61,134 at P 216; EIS at 4-1222.

[17] Certificate Order, 171 FERC ¶ 61,134 at P 251.

cannot assess the significance of the Project's impact on climate change[18] while concluding that all environmental impacts associated with the Project are acceptable and not inconsistent with the public interest.[19] That is unreasoned and an abdication of our responsibility to give climate change the "hard look" that the law demands.[20]

9. It also means that the Project's impact on climate change does not play a meaningful role in the Commission's public interest determination, no matter how often the Commission assures us that it does. Using the approach in today's order, the Commission will always conclude that a project will not have a significant environmental impact irrespective of that project's actual GHG emissions or those emissions' impact on climate change. If the Commission's conclusion will not change no matter how many GHG emissions a project causes, those emissions cannot, as a logical matter, play a meaningful role in the Commission's public interest determination. A public interest determination that systematically excludes the most important environmental consideration of our time is contrary to law, arbitrary and capricious, and not the product of reasoned decisionmaking.

10. The failure to meaningfully consider the Project's GHG emissions is all-the-more indefensible given the volume of GHG emissions at issue in this proceeding. Upon completion, the Project will directly release 16.3 million tons of GHG emissions per year with maximum methane flare, in addition to the 2.2 million tons of GHG emissions

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[18] *Id.* P 216; *see also* EIS at 4-1222 ("[W]e are unable to determine the significance of the Project's contribution to climate change.").

[19] Certificate Order, 171 FERC ¶ 61,134 at 251 (concluding that all environmental impacts associated with the project are "acceptable" and the Commission finds that the LNG Project is not inconsistent with the public interest).

[20] *See, e.g.*, *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1322 (D.C. Cir. 2015) (explaining that agencies cannot overlook a single environmental consequence if it is even "arguably significant"); *see also Michigan v. EPA*, 135 S. Ct. 2699, 2706 (2015) ("Not only must an agency's decreed result be within the scope of its lawful authority, but the process by which it reaches that result must be logical and rational." (internal quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n, Inc. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983) (explaining that agency action is "arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem, [or] offered an explanation for its decision that runs counter to the evidence before the agency").

during the eight years of construction.[21] To grasp the magnitude of these emissions, 16.3 million metric tons amounts to an annual increase in Alaska's total GHG emissions of nearly 50 percent.[22] Put another way, these emissions are equivalent to the emissions of 3.5 million vehicles, four times the number of passenger vehicles in the entire state of Alaska.[23] The Order recognizes that climate change is "driven by accumulation of GHGs in the atmosphere through combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture, clearing of forests, and other natural sources"[24] and that the "GHG emissions from the construction and operation of the [P]roject would increase the atmospheric concentration of GHGs in combination with past and future emissions from all other sources and contribute incrementally to future climate change impacts."[25] In light of this undisputed relationship between anthropogenic GHG emissions and climate change, the Commission must carefully consider the Project's contribution to climate change when determining whether the Project is consistent with the public interest—a task that it entirely fails to accomplish in today's order. The Commission's fervent insistence that it took such a 'hard look' at climate change is no substitute for actually having done so.

B. The Commission's Consideration of the Project's Other Adverse Impacts Is Also Arbitrary and Capricious

11. In addition, the Commission concludes that the Project will result in several significant, and often permanent, adverse impacts on the environment. The Project is expected to adversely affect six endangered species including polar bears, seals and whales. In addition, even with mitigation measures, the Project is expected to have a significant adverse impact on the Central Artic Herd of caribou, permafrost, forest, and

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[21] Certificate Order, 171 FERC ¶ 61,134 at P 214; EIS at § 4.15, Tables 4.15.4-1–4.15.4-5 (construction emissions by construction year); Tables 4.15.5-1, 4.15.5-10–4.15.5-15, 4.15.5-20 (annual operational emissions). *See also* Certificate Order, 171 FERC ¶ 61,134 at PP 211, 213 (providing corrections to the GHG figures in the EIS).

[22] Certificate Order, 171 FERC ¶ 61,134 at P 214.

[23] This figure was calculated using the U.S. Environmental Protection Agency's (EPA) Greenhouse Gas Equivalencies Calculator. *See* U.S. Envtl. Prot. Agency, Greenhouse Gas Equivalencies Calculator, https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator (last visited May 20, 2019).

[24] EIS at 4-1220.

[25] Certificate Order, 171 FERC ¶ 61,134 at P 216; EIS at 4-1221.

air quality in areas such as Denali National Park.[26] The Commission discloses these adverse impacts in the EIS and gives them a mention in today's order.[27] But the Commission makes no effort to wrestle with those impacts or explain how they factor meaningfully into the Commission's public interest analysis. Simply deeming those adverse impacts to be "acceptable" without any explanation of how that conclusory finding supports the Commission's public interest determination is a far cry from reasoned decisionmaking.

12. The Sierra Club makes this very point.[28] The Commission responds by reciting its burden of proof, namely that LNG export facilities must be approved unless they are shown to be inconsistent with the public interest, and then pointing to the economic benefits that may result from the Project.[29] It then summarily concludes that the Project's significant adverse environmental impacts "do not amount to an affirmative showing of inconsistency with the public interest"[30] and that all environmental impacts are "acceptable considering the public benefits."[31] But it never explains how it makes that determination or why those serious environmental consequences are acceptable given the Project's benefits. Simply labeling them "acceptable" does not make it so or comply with our obligation to provide a rationale reached by 'reasoned decisionmaking,' including an examination of the relevant data and "'a reasoned explanation supported by a stated connection between the facts found and the choice made.'"[32] Indeed, the Commission's willingness to brush off environmental impacts in its public interest analysis would seem to suggest that the Commission's environmental analysis is more

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[26] EIS at ES-7, 5-1.

[27] Certificate Order, 171 FERC ¶ 61,134 at PP 25 (generally), 74 (permafrost), 91 (forest communities), 105 (Central Artic Herd of caribou), 209 (air quality in nationally designated areas).

[28] Sierra Club May 22, 2017 Motion to Intervene at 4 (contending that these adverse environmental impacts "weigh heavily against the project's consistency with public interest").

[29] Certificate Order, 171 FERC ¶ 61,134 at PP 16-17.

[30] *Id.* P 14.

[31] *Id.* P 251.

[32] *Turlock Irrigation Dist. v. FERC*, 786 F.3d 18, 25 (D.C. Cir. 2015) (quoting *U.S. Dept. of Interior v. FERC*, 952 F.2d 538, 543 (D.C. Cir. 1992)).

checking the box than part of a serious effort to balance the Project's benefits and harms when assessing consistency with the public interest.

13. That is particularly so in this order, where the Commission makes its public interest finding without even bothering to wait for determination from the relevant resource agencies about the Project's impact on six endangered species—the polar bear, humpback whale, Cook Inlet beluga whale, bearded seal, ringed seal, and spectacled eider.[33] I would have thought that those agencies' final conclusions about the Project's impact on these endangered would be relevant, even essential, to our public interest determination. The fact that the Commission will not authorize any construction on the Project until it receives those final conclusions is not an excuse for making a public interest determination without them.[34]

14. Finally, the Commission's public interest analysis makes no effort to recognize, much less wrestle with, the considerable uncertainty inherent in developing such a complex project in a hostile and fragile ecosystem. The "LNG export terminal" at issue, includes a gas processing facility located more than 800 miles away (a distance roughly the size of Texas at its widest point) and a connecting pipeline that runs through a vast swathe of the Arctic.[35] The Commission has little familiarity with these circumstances, having only once before permitted a jurisdictional pipeline in Alaska[36] and having "never

[33] The Commission currently concludes in its Biological Assessment submitted to the relevant Federal agencies that the Project would be "likely to adversely affect" the six endangered species, but would not jeopardize the population of these species. Certificate Order, 171 FERC ¶ 61,134 at PP 136-137. A full discussion of staff's "likely to adversely affect" determinations are provided in the Biological Assessment and briefly summarized in the EIS at Table 4.8.1-6.

[34] I recognize that the Commission need not have perfect information before making a public interest determination, *see U.S. Dep't of the Interior v. FERC*, 952 F.2d 538, 546 (D.C. Cir. 1992) (holding that agency need only establish a record to support its decisions and need not definitively resolve all environmental concerns), but today's order stretches that principle past all reasonable limits in concluding that it can determine the public interest without meaningful input from the resource agencies about its impacts on these six endangered species.

[35] Certificate Order, 171 FERC ¶ 61,134 at P 4.

[36] *See Yukon Pacific Co. L.P.*, 71 FERC ¶ 61,197 (1995). Notably, the Commission denied a request to extend the time to commence construction of the project and it ultimately was never built. *See Yukon Pacific Co.*, Docket No. CP88-105-000 (May 14, 2010) (delegated order).

exerted NGA section 3 jurisdiction over a project of this size."[37] Under such circumstances, one might be excused for assuming that the Commission would address that uncertainty in its public interest determination and adopt a conservative approach to managing the Project's impacts—including rigorous mitigation measures—that reflect our limited experience.

15. Instead, the Commission's public interest finding makes no mention of the uncertainty associated with the Project or the yawning gaps in our understanding of how it will affect critical resources. Consider the caribou. The Commission finds that running an 800-mile pipeline through the middle of the range used by the Central Arctic Herd of caribou will have a significant adverse effect on both the animals and the communities that rely on them for subsistence.[38] If anything, that seems like an understatement. Without complete information at the outset, the Commission requires the Project's developer to study those effects *after* the Project has gone into service, with the opportunity to impose to-be developed mitigation measures at some point in the future in lieu of imposing concrete mitigation measures at this time.[39] I recognize that not all the impacts of such an unprecedented project can be understood and accounted for a decade before it is built and support the effort to collect more information. Still, I would have thought that reasoned decisionmaking requires the Commission to account for that uncertainty in its public interest determination and, at the very least, explain why the impact is "acceptable" and does not raise serious questions about whether the Project satisfies the statutory standard.

II. <u>The Commission Fails to Satisfy Its Obligations under NEPA</u>

16. The Commission's NEPA analysis of the Project's GHG emissions is similarly flawed. In order to evaluate the environmental consequences of the Project under NEPA, the Commission must consider the harm caused by its GHG emissions and "evaluate the 'incremental impact' that those emissions will have on climate change or the environment more generally."[40] As noted, the operation of the Project will emit more than 16 million

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[37] Certificate Order, 171 FERC ¶ 61,134 at P 9.

[38] *Id.* P 105; EIS at 4-306, 4-312.

[39] Certificate Order, 171 FERC ¶ 61,134 at P 107; *see also id.*, app. envtl. condition 24.

[40] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1216 (9th Cir. 2008); *WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 51 (D.D.C. 2019) (explaining that the agency was required to "provide the information necessary for the public and agency decisionmakers to understand the degree to which

tons of GHG emissions per year.[41] Although quantifying the Project's GHG emissions is a necessary step toward meeting the Commission's NEPA obligations, listing the volume of emissions alone is insufficient.[42]

17. As an initial matter, identifying the consequences that those emissions will have for climate change is essential if NEPA is to play the disclosure and good government roles for which it was designed. The Supreme Court has explained that NEPA's purpose is to "ensure[] that the agency, in reaching its decision, will have available, and will carefully consider, detailed information concerning significant environmental impacts" and to "guarantee[] that the relevant information will be made available to the larger audience that may also play a role in both the decisionmaking process and the implementation of that decision."[43] It is hard to see how hiding the ball by refusing to assess the significance of the Project's climate impacts is consistent with either of those purposes.

18. In addition, under NEPA, a finding of significance informs the Commission's inquiry into potential ways of mitigating environmental impacts.[44] An environmental

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[its] decisions at issue would contribute" to the "impacts of climate change in the state, the region, and across the country").

[41] Certificate Order, 171 FERC ¶ 61,134 at P 214; EIS at § 4.15, Tables 4.15.4-1–4.15.4-5 (construction emissions by construction year); Tables 4.15.5-1, 4.15.5-10–4.15.5-15, 4.15.5-20 (annual operational emissions). *See also* Certificate Order, 171 FERC ¶ 61,134 at PP 211, 213 (providing corrections to the GHG figures in the EIS).

[42] *See Ctr. for Biological Diversity*, 538 F.3d at 1216 ("While the [environmental document] quantifies the expected amount of CO_2 emitted . . . , it does not evaluate the 'incremental impact' that these emissions will have on climate change or on the environment more generally."); *Klamath-Siskiyou Wildlands Ctr. v. Bureau of Land Mgmt.*, 387 F.3d 989, 995 (9th Cir. 2004) ("A calculation of the total number of acres to be harvested in the watershed is a necessary component . . . , but it is not a sufficient description of the actual environmental effects that can be expected from logging those acres.").

[43] *Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 768 (2004) (citing *Robertson v. Methow Valley Citizens Coun.*, 490 U.S. 332, 349 (1989)).

[44] 40 C.F.R. § 1502.16 (2019) (requiring an implementing agency to form a "scientific and analytic basis for the comparisons" of the environmental consequences of its action in its environmental review, which "shall include discussions of . . . [d]irect effects and their significance.").

review document must "contain a detailed discussion of possible mitigation measures" to address adverse environmental impacts.[45] "Without such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects" of a project, meaning that an examination of possible mitigation measures is necessary to ensure that the agency has taken a "hard look" at the environmental consequences of the action at issue.[46]

19. The Commission responds that it need not determine whether the Project's contribution to climate change is significant because "[t]here is no universally accepted methodology" for assessing the harms caused by the Project's contribution to climate change.[47] But that does not excuse the Commission's failure to evaluate these emissions. As an initial matter, the lack of a single consensus methodology does not prevent the Commission from adopting *a* methodology, even if it is not universally accepted. The Commission could, for example, select one methodology to inform its reasoning while also disclosing its potential limitations or the Commission could employ multiple methodologies to identify a range of potential impacts on climate change. In refusing to assess a project's climate impacts without a perfect model for doing so, the Commission sets a standard for its climate analysis that is higher than it requires for any other environmental impact.

20. In any case, the Commission also can use its expertise to consider all factors and determine, quantitatively or qualitatively, whether the Project's GHG emissions have a significant impact on climate change. That is precisely what the Commission does in other aspects of its environmental review. Consider, for example, the Commission's findings that the Project will not have a significant effect on issues such as "scrub and

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[45] *Robertson*, 490 U.S. at 351.

[46] *Id.* at 352.

[47] EIS at 4-1222 ("Currently, there is no universally accepted methodology to attribute discrete, quantifiable, physical effects on the environment to the Project's incremental contribution to GHGs."); *see also* Certificate Order, 171 FERC ¶ 61,134 at PP 216 ("Without either the ability to determine discrete resource impacts or an established target to compare GHG emissions against, the final EIS concludes that it cannot determine the significance of the project's contribution to climate change.").

herbaceous plant communities,"[48] "subsistence users"[49] and "forest communities."[50] Notwithstanding the lack of any "universally-accepted methodology" to assess these impacts, the Commission uses its judgment to conduct a qualitative review, and assess the significance of the Project's effect on those considerations.[51] The Commission's refusal to, at the very least, exercise similar qualitative judgment to assess the significance of GHG emissions here is arbitrary and capricious.

21. And even if the Commission were to determine that the Project's GHG emissions are significant, that is not the end of the analysis. Instead, as noted above, the Commission could blunt those impacts through mitigation—as the Commission often does with regard to other environmental impacts. The Supreme Court has held that an environmental review must "contain a detailed discussion of possible mitigation

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[48] Certificate Order, 171 FERC ¶ 61,134 at P 89 (finding that the "impacts on scrub and herbaceous plant communities would be less than significant" based on a qualitative assessment of "the small areas affected relative to the larger watersheds and their shorter recovery time relative to forest communities").

[49] EIS at 4-693 (finding that the Project "could have long-term or permanent effects" on some subsistence users, or communities that rely on land and the resources it provides in support of life, "by altering caribou migration patterns" which would "result in a disproportionate impact on the minority and low-income populations in Utqiagvik, Nuiqsut, and Anaktuvuk Pass." Notwithstanding this impact, the Commission concludes it "do[es] not expect those impacts would be high and adverse" without any explanation of the universally-accepted methodology for determining what magnitude of impact equates to "high and adverse.").

[50] Certificate Order, 171 FERC ¶ 61,134 at PP 90-91 (finding that the Project would results in the permanent loss of 8,512 acres of forest and these"[i]mpacts on forest communities would be significant given the amount of habitat affected and the longer recovery period for this vegetation type," yet the Commission provides no universal methodology for determining that this quantity of impact would result in significant impacts on the environment); *see also* EIS at 4-282.

[51] In fact, the Commission affirmatively defines this qualitative approach, stating that the determination of significance for all environmental impacts involves a consideration "the duration of the impact as well as the geographic, biological, and/or social context in which the effects would occur, and the intensity (e.g., severity) of the impact," further acknowledging that "[t]he context and intensity vary by resource and impact." EIS at 4-1.

measures" to address adverse environmental impacts.[52] As noted above, "[w]ithout such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects."[53]

22. Consistent with this obligation, the EIS discusses mitigation measures to ensure that the Project's adverse environmental impacts (other than its GHG emissions) are reduced to less-than-significant levels.[54] And throughout today's order, the Commission uses its broad conditioning authority under section 3 of the NGA[55] to implement these mitigation measures, which support its public interest finding.[56] Despite this use of our conditioning authority to mitigate adverse impacts, the Project's climate impacts continue to be treated differently, as the Commission refuses to identify any potential climate mitigation measures or discuss how such measures might affect the magnitude of the Project's impact on climate change.

23. Finally, the Commission's refusal to seriously consider the significance of the impact of the Project's GHG emissions is even more mystifying because NEPA "does not dictate particular decisional outcomes."[57] NEPA "'merely prohibits uninformed—rather than unwise—agency action.'"[58] The Commission could find that a project contributes significantly to climate change, but that it is nevertheless in the public interest because its benefits outweigh its adverse impacts, including on climate change. In other words,

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[52] *Robertson*, 490 U.S. at 351.

[53] *Id.* at 351-52; *see also* 40 C.F.R. § 1508.20 (2019) (defining mitigation); *id.* § 1508.25 (including in the scope of an environmental impact statement mitigation measures).

[54] *See, e.g.*, Certificate Order, 171 FERC ¶ 61,134 at n.39 (generally), PP 124, 128 (Essential Fish Habitat), 163 (visual resources).

[55] 15 U.S.C. § 717b(e)(3)(A); Certificate Order, Certificate Order, 171 FERC ¶ 61,134 at P 250 ("[T]he Commission has the authority to take whatever steps are necessary to ensure the protection of environmental resources . . . , including authority to impose any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the order.").

[56] *See* Certificate Order, 171 FERC ¶ 61,134 at P 250 (explaining that the environmental conditions ensure that the Project's environmental impacts are consistent with those anticipated by the environmental analysis).

[57] *Sierra Club v. U.S. Army Corps of Engineers*, 803 F.3d 31, 37 (D.C. Cir. 2015).

[58] *Id.* (quoting *Robertson*, 490 U.S. at 351).

taking the matter seriously—and rigorously examining a project's impacts on climate change—does not necessarily prevent any of my colleagues from ultimately concluding that a project satisfies the relevant public interest standard.

For these reasons, I respectfully dissent.

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Richard Glick
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Alaska Gasline Development Corporation Docket No. CP17-178-000

(Issued May 21, 2020)

McNAMEE, Commissioner, *concurring*:

1. Today's order grants Alaska Gasline Development Corporation (AGDC) authorization under section 3 of the Natural Gas Act (NGA)[1] to site, construct, and operate the Alaska LNG Project (Project).[2] The Project will consist of a gas treatment plant located in the Prudhoe Bay Unit of Alaska's North Slope, and two natural gas pipelines connecting production units to the gas treatment plant; an approximately 806.9-mile-long, 42-inch-diameter mainline pipeline capable of transporting up to 3.9 billion cubic feet of gas per day from the gas treatment plant to the liquefaction facilities; 344,000 horsepower of compression located at eight compressor stations along the mainline pipeline; and liquefaction facilities on the Kenai Peninsula designed to produce up to 20 million metric tons per annum of liquefied natural gas (LNG) for export.[3]

2. I fully support the order as it complies with the Commission's statutory responsibilities under the NGA and National Environmental Policy Act (NEPA). The order determines that the siting, construction, and operation of the Project is not inconsistent with the public interest.[4] The order also finds that the environmental impacts associated with the Project are acceptable.[5] Further, consistent with the holding in *Sierra Club v. FERC* (*Sabal Trail*),[6] the Commission quantified and considered the direct and

[1] 15 U.S.C. § 717b(e) (2018) ("The Commission shall have the exclusive authority to approve or deny an application for the siting, construction, or operation of an LNG terminal.").

[2] *Alaska Gasline Development Corp.*, 171 FERC ¶ 61,134 (2020).

[3] *Id.* P 3.

[4] *Id.* P 17.

[5] *Id.* P 251.

[6] 867 F.3d 1357 (D.C. Cir. 2017).

indirect greenhouse gases (GHGs) emitted during the construction and operation of the Project.[7]

3. Although I fully support today's order authorizing the Project, I write separately to address what I perceive to be a misinterpretation of the Commission's authority under the NGA and NEPA. There have been contentions that the NGA authorizes the Commission to establish measures to mitigate project-related GHG emissions, and that the Commission violates the NGA and NEPA by not determining whether GHG emissions significantly affect the environment. I disagree.

4. I believe that the Commission can consider project-related emissions in its NGA section 3 public interest determination and is required to consider them in its NEPA analysis. However, the Commission has no reasoned basis to determine whether GHG emissions will have a significant effect on climate change nor the authority to establish its own basis for making such a determination. Further, the Commission does not have the authority to unilaterally establish measures to mitigate GHG emissions. It is my intention that my discussion below will assist the Commission, the courts, and other parties in their arguments regarding the Commission's consideration of a project's effect on climate change.

I. The Commission has no standard for determining whether GHG emissions significantly affect the environment

5. Commenters argue that the Commission violates the NGA and NEPA by not determining the significance of GHG emissions that are effects of the Project.[8] My colleague has made similar arguments.[9] He has challenged the Commission's explanation that it cannot determine significance because there is no standard for determining the significance of GHG emissions.[10] He has argued that the Commission can adopt the Social Cost of Carbon[11] to determine whether GHG emissions are significant or rely on its own expertise as it does for other environmental resources, such

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[7] *Id.* PP 213-216

[8] *See, e.g.*, Institute for Policy Integrity et al. October 3, 2019 Comments at 1.

[9] *See Annova LNG Common Infrastructure, LLC*, 169 FERC ¶ 61,132 (Glick, Comm'r, dissenting at PP 2, 5, 14) (Annova Dissent).

[10] *Id.* P 16.

[11] *Id.* P 17.

as visual resources and surface water resources.[12] He has suggested that the Commission does not make a finding of significance in order to conclude that a project is not inconsistent with the public interest.[13]

6. I disagree with these contentions. The Social Cost of Carbon is not a suitable method for determining whether GHG emissions that are caused by a proposed project will have a significant effect on climate change and the Commission has no authority or reasoned basis using its own expertise to make such a determination.

A. **Social Cost of Carbon is not a suitable method to determine significance**

7. The Commission has found, and I agree, that the Social Cost of Carbon is not a suitable method for the Commission to determine significance of GHG emissions.[14] Because the courts have repeatedly upheld the Commission's reasoning,[15] I will not restate the Commission's reasoning here.

8. However, I will address the suggestion that the Social Cost of Carbon can translate a project's impact on climate change into "concrete and comprehensible terms" that will

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[12] *Id.* P 18 n.289.

[13] *Id.* P 5.

[14] *Fla. Se. Connection, LLC*, 162 FERC ¶ 61,233, at P 48 (2018).

[15] *Appalachian Voices*, 2019 WL 847199, *2; *EarthReports, Inc. v. FERC*, 828 F.3d 949, 956 (D.C. Cir. 2016); *Sierra Club v. FERC*, 672 F. App'x 38, (D.C. Cir. 2016); *see also 350 Montana v. Bernhardt,* No. CV 19-12-M-DWM, 2020 WL 1139674, *6 (D. Mont. March 9, 2020) (upholding the agency's decision to not use the Social Cost of Carbon because it is too uncertain and indeterminate to be useful); *Citizens for a Healthy Cmty. v. U.S. Bureau of Land Mgmt.*, 377 F. Supp. 3d 1223, 1239-41 (D. Colo. 2019) (upholding the agency's decision to not use the Social Cost of Carbon); *WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 77-79 (D.D.C. 2019) (upholding the agency's decision to not use the Social Cost of Carbon); *High Country Conservation Advocates v. U.S. Forest Serv.*, 333 F. Supp. 3d 1107, 1132 (D. Colo. 2018) vacated and remanded on other grounds 2020 WL 994988 (10th Cir. March 2, 2020) ("[T]he High Country decision did not mandate that the Agencies apply the social cost of carbon protocol in their decisions; the court merely found arbitrary the Agencies' failure to do so without explanation.").

help inform agency decision-makers and the public at large.[16] The Social Cost of Carbon, described as an estimate of "the monetized damages associated with an incremental increase in carbon emissions in a given year,"[17] may appear straightforward. On closer inspection, however, the Social Cost of Carbon and its calculated outputs are not so simple to interpret or evaluate.[18] When the Social Cost of Carbon estimates that one metric ton of CO_2 costs $12 (the 2020 cost for a discount rate of 5 percent),[19] agency decision-makers and the public have no basis or benchmark to determine whether that cost is significant. Bare numbers standing alone simply *cannot* ascribe significance.

B. The Commission has no authority or reasoned basis to establish its own framework

9. Some argue that the lack of externally established targets does not relieve the Commission from establishing a framework or targets on its own. Some have suggested that the Commission can make up its own framework, citing the Commission's framework for determining return on equity (ROE) as an example. However, they overlook the fact that Congress designated the U.S. Environmental Protection Agency (EPA), not the Commission, with exclusive authority to determine the amount of

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[16] Annova Dissent P 17.

[17] Interagency Working Group on the Social Cost of Greenhouse Gases, *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866* at 1 (Aug. 2016), https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf (2016 Technical Support Document).

[18] In fact, the website for the Climate Framework for Uncertainty Negotiation and Distribution (FUND) – one of the three integrated assessment models that the Social Cost of Carbon uses – states "[m]odels are often quite useless in unexperienced hands, and sometimes misleading. No one is smart enough to master in a short period what took someone else years to develop. Not-understood models are irrelevant, half-understood models are treacherous, and mis-understood models dangerous." FUND-Climate Framework for Uncertainty, Negotiation and Distribution, http://www.fund-model.org/ (LAST VISITED Nov. 18, 2019).

[19] *See* 2016 Technical Support Document at 4. The Social Cost of Carbon produces wide-ranging dollar values based upon a chosen discount rate, and the assumptions made. The Interagency Working Group on Social Cost of Greenhouse Gases estimated in 2016 that the Social Cost of one ton of carbon dioxide for the year 2020 ranged from $12 to $123. *Id.*

emissions that are harmful to the environment. In addition, there are no available resources or agency expertise upon which the Commission could reasonably base a framework or target.

10. As I explain below, Congress enacted the Clean Air Act to establish an all-encompassing regulatory program, supervised by the EPA to deal comprehensively with interstate air pollution. Section 111 of the Clean Air Act directs the Administrator of the EPA to identify stationary sources that "in his judgment cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare"[20] and to establish standards of performance for the identified stationary sources.[21] Thus, the EPA has exclusive authority for determining whether emissions from pipeline facilities will have a significant effect on the environment and for establishing an emissions control regime.

11. Further, the Commission is not positioned to unilaterally establish a standard for determining whether GHG emissions will significantly affect the environment when there is neither federal guidance nor an accepted scientific consensus on these matters.[22] This inability to find an acceptable methodology is not for a lack of trying. The Commission reviews the climate science, state and national targets, and climate models that could inform its decision-making.[23]

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[20] 42 U.S.C. § 7411(b)(1)(A) (2018).

[21] *Id.* § 7411(b)(1)(B).

[22] The Council on Environmental Quality's 2019 Draft Greenhouse Gas Guidance states, "[a]gencies need not undertake new research or analysis of potential climate effects and may rely on available information and relevant scientific literature." CEQ, *Draft National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions*, 84 Fed. Reg. 30,097, 30,098 (June 26, 2019); *see also* CEQ FINAL GUIDANCE FOR FEDERAL DEPARTMENTS AND AGENCIES ON CONSIDERATION OF GREENHOUSE GAS EMISSIONS AND THE EFFECTS OF CLIMATE CHANGE IN NATIONAL ENVIRONMENTAL POLICY ACT REVIEWS at 22 (Aug. 1, 2016) ("agencies need not undertake new research or analysis of potential climate change impacts in the proposed action area, but may instead summarize and incorporate by reference the relevant scientific literature"), https://ceq.doe.gov/docs/ceq-regulations-and-guidance/nepa_final_ghg_guidance.pdf.

[23] *Fla. Se. Connection, LLC*, 162 FERC ¶ 61,233, at P 36; *see also WildEarth Guardians*, 738 F.3d 298, 309 (D.C. Cir. 2013) ("Because current science does not allow for the specificity demanded by the Appellants, the BLM was not required to identify specific effects on the climate in order to prepare an adequate EIS.").

12. Moreover, assessing the significance of project effects on climate change is unlike the Commission's determination of ROE. Establishing ROE has been one of the core functions of the Commission since its inception under the FPA as the Federal Power Commission.[24] And, setting ROE has been an activity of state public utility commissions, even before the creation of the Federal Power Commission.[25] The Commission's methodology is also founded in established economic theory.[26] In contrast, assessing the significance of GHG emissions is not one of the Commission's core missions and there is no suitable methodology for making such determination.

13. It has been argued that the Commission can establish its own methodology for determining significance, pointing out that the Commission has determined the significance of effects on visual resources and surface water resources using its own expertise and without generally accepted significance criteria or a standard methodology.

14. I disagree. As an initial matter, it is important to note that when the Commission states it has no suitable methodology for determining the significance of GHG emissions, the Commission means that it has no reasoned basis for making such finding. The Commission's findings regarding significance for visual resources and surface water resources have a reasoned basis. For example for impacts to visual resources, the Commission reasonably finds that project construction and operation would not significantly affect visual resources based on the Final Environmental Impact Statement's (EIS) assessment using the U.S. Bureau of Land Management's (BLM) Visual Resource Management System. The Visual Resource Management System provides a process for assessing visual impacts, including defining the management directives for each landscape, conducting simulations of future visual conditions at key observation points, describing the contrast the Project would create, and then describing visual impacts based on the degree to which contrast affects the ability to achieve visual

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[24] *Hope*, 320 U.S. 591 (1944); *FPC v. Nat. Gas Pipeline Co. of America*, 315 U.S. 575 (1942).

[25] *See, e.g., Willcox v. Consol. Gas Co.*, 212 U.S. 19, 41 (1909) (finding New York State must provide "a fair return upon the reasonable value of the property at the time it is being used for the public.").

[26] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (2019) (describing the Commission's use of the Discounted Cash Flow model that was originally developed in the 1950s as a method for investors to estimate the value of securities).

resource objectives.[27] Given that visual conditions cannot be evaluated from every possible viewpoint, BLM requires the identification of key observation points, which may include "critical viewpoints," "typical views encountered in representative landscapes," and "any special project or landscape features."[28]

15. To assess the Project's visual impacts, AGDC together with the National Park Service identified a total of 91 key observation points.[29] Using definitions provided in *BLM Manual H-8431*, the Final EIS determines whether impacts to each key observation point would be high, moderate, or low, or whether there would be no effect.[30] Of the 91 identified key observation points, the Final EIS states that project construction would have a high impact on 11 key observation points and project operation would have a high impact on 9 key observation points.[31] For selected key observations points, including those with anticipated high impacts, the Final EIS then discusses AGDC's proposed mitigation, such as AGDC's implementation of its *Project Revegetation Plan* and *Project Lighting Plan*.[32] Based on this information, the Commission was able to anticipate the effect that the Project would have on existing visual resources and made a reasoned finding that the Project's effect on visual resources would not significantly affect existing visual resources.

16. In contrast, the Commission cannot anticipate the effects that the Project would have on the existing climate, and, thus, has no reasoned basis to determine whether a project has a significant effect on the climate. The Commission can only quantify the amount of project emissions. That calculated number, however, cannot inform the Commission on the specific effects that the Project could have on climate change, e.g., increase of sea level rise, effect on weather patterns, or effect on ocean acidification. Nor

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[27] Final EIS at 4-598 – 4-599.

[28] *Id.* at 4-588 (quoting Bureau of Land Management, BLM Manual H-8431 — Visual Resource Contrast Rating (1986), *available at* http://blmwyomingvisual.anl.gov/docs/BLM_VCR_8431.pdf).

[29] *Id.* at 4-588.

[30] *Id.* at 4-603.

[31] *Id.* at 4-620.

[32] *Id.* at Table 4.10.2-2; *see also id.* at 4-603 ("*BLM Manual H-8431* states 'mitigating measures should be prepared for all adverse contrasts that can be reduced.'").

are there acceptable scientific models that the Commission may use to attribute every ton of GHG emissions to a specific physical climate change effect.

17. Without adequate support or a reasoned target, the Commission cannot ascribe significance to particular amounts of GHG emissions. To do so would not only exceed our agency's authority, but would risk reversal upon judicial review. Courts require agencies to "consider[] the relevant factors and articulate[] a rational connection between the facts found and the choice made."[33] Simply put, stating that an amount of GHG emissions appears significant without any reasoned support fails to meet the agency's obligations under the Administrative Procedure Act (APA).

II. The NGA does not contemplate the Commission establishing mitigation for GHG emissions from LNG Facilities

18. There have also been contentions that the Commission should require the mitigation of GHG emissions related to the authorized facilities.[34] I understand these suggestions as proposing a carbon emissions fee, offsets or tax (similar to the Corps' compensatory wetland mitigation program), technology requirements (such as scrubbers), or emission caps. Some argue that the Commission can require such mitigation under NGA section 3(e)(3)(A), which provides "the Commission may approve an application . . . in whole or in part, with such modifications and upon such terms and conditions the Commission find necessary or appropriate."[35]

19. I disagree. The Commission cannot interpret NGA section 3(e)(3)(A) to allow the Commission to unilaterally establish measures to mitigate GHG emissions because Congress, through the Clean Air Act, assigned the EPA and the States exclusive authority to establish such measures. Congress designated the EPA as the expert agency "best

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[33] *City of Tacoma v. FERC*, 460 F.3d 53, 76 (D.C Cir. 2006) (quoting *Ariz. Cattle Growers' Ass'n v. FWS*, 273 F.3d 1229, 1235-36 (9th Cir. 2001)); *see also American Rivers v. FERC*, 895 F.3d 32, 51 (D.C. Cir. 2018) (" . . . the Commission's NEPA analysis was woefully light on reliable data and reasoned analysis and heavy on unsubstantiated inferences and *non sequiturs*") (italics in original); *Found. for N. Am. Wild Sheep v. U.S. Dep't of Agr.*, 681 F.2d 1172, 1179 (9th Cir. 1982) ("The EA provides no foundation for the inference that a valid comparison may be drawn between the sheep's reaction to hikers and their reaction to large, noisy ten-wheel ore trucks.").

[34] Annova Dissent P 19.

[35] 15 U.S.C. § 717b(e)(3)(A) (2018).

suited to serve as primary regulator of greenhouse gas emissions,"[36] not the Commission.

20. The Clean Air Act establishes an all-encompassing regulatory program, supervised by the EPA to deal comprehensively with interstate air pollution.[37] Congress entrusted the Administrator of the EPA with significant discretion to determine appropriate emissions measures. Congress delegated the Administrator the authority to determine whether pipelines and other stationary sources endanger public health and welfare; section 111 of the Clean Air Act directs the Administrator of the EPA "to publish (and from time to time thereafter shall revise) a list of categories of stationary sources. He shall include a category of sources in such list if in *his judgment* it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare"[38] and to establish standards of performance for the identified stationary sources.[39] The Clean Air Act requires the Administrator to conduct complex balancing when determining a standard of performance, taking into consideration what is technologically achievable and the cost to achieve that standard.[40]

21. In addition, the Clean Air Act allows the Administrator to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards."[41] The Act also permits the Administrator, with the consent of the Governor of the State in which the source is to be located, to waive its requirements "to encourage the use of an innovative technological system or systems of continuous emission reduction."[42]

22. Congress also intended that states would have a role in establishing measures to mitigate emissions from stationary sources. Section 111(f) notes that "[b]efore promulgating any regulations . . . or listing any category of major stationary sources . . . the Administrator shall consult with appropriate representatives of the Governors and of

[36] *American Elec. Power Co., Inc. v. Conn.*, 564 U.S. 410, 428 (2011).

[37] *See id.* at 419.

[38] 42 U.S.C. § 7411(b)(1)(A) (2018) (emphasis added).

[39] *Id.* § 7411(b)(1)(B).

[40] *Id.* § 7411(a)(1).

[41] *Id.* § 7411(a)(2).

[42] *Id.* § 7411(j)(1)(A).

State air pollution control agencies."[43]

23. Thus, the text of the Clean Air Act demonstrates it is improbable that NGA section 3(e)(3)(A) allows the Commission to establish GHG emission standards or mitigation measures out of whole cloth. To argue otherwise would defeat the significant discretion and complex balancing that the Clean Air Act entrusts in the EPA Administrator, and would eliminate the role of the States.

24. Furthermore, to argue that the Commission may use its NGA conditioning authority to establish GHG emission mitigation—a field in which the Commission has no expertise—and address climate change—an issue that has been subject to profound debate across our nation for decades—is an extraordinary leap. The Supreme Court's "major rules" canon advises that agency rules on issues that have vast economic and political significance must be treated "with a measure of skepticism" and require Congress to provide clear authorization.[44] The Court has articulated this canon because Congress does not "hide elephants in mouseholes"[45] and "Congress is more likely to have focused upon, and answered, major questions, while leaving interstitial matters to answer themselves in the course of the statute's daily administration."[46]

25. Courts would undoubtedly treat with skepticism any attempt by the Commission to establish out of whole cloth measures to mitigate GHG emissions. Congress has

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[43] *Id.* § 7411(f)(3).

[44] *Util. Air Regulatory Grp. v. EPA*, 573 U.S. 302, 324 (2014); *FDA v. Brown & Williamson Tobacco Corp,* 529 U.S. 120, 160 (2000) ("Congress could not have intended to delegate a decision of such economic and political significance to an agency in so cryptic a fashion."); *see also Gonzales v. Oregon*, 546 U.S. 243, 267-68 (2006) (finding regulation regarding issue of profound debate suspect).

[45] *Whitman v. American Trucking Ass.,* 531 U.S. 457, 468 (2001).

[46] *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159 (quoting Justice Breyer, *Judicial Review of Questions of Law and Policy*, 38 ADMIN. L. REV. 363, 370 (1986)); *see also* Abbe R. Gluck & Lisa Schultz Bressman, *Statutory Interpretation from the Inside—An Empirical Study of Congressional Drafting, Delegation, and the Canons: PART I*, 65 STAN. L. REV. 901, 1004 (2013) ("Major policy questions, major economic questions, major political questions, preemption questions are all the same. Drafters don't intend to leave them unresolved.")

introduced climate change bills since at least 1977,[47] over four decades ago. Over the last 15 years, Congress has introduced and failed to pass 70 legislative bills to reduce GHG emissions—29 of those were carbon emission fees or taxes.[48] For the Commission to suddenly declare such power resides in the long-extant NGA and that Congress's efforts were superfluous strains credibility. Requiring LNG facilities and related pipelines to pay a carbon emissions fee or tax, or to invest in GHG mitigation would be a major rule, and Congress has made no indication that the Commission has such authority.

26. Some may make the argument that the Commission can require mitigation without establishing a standard. I disagree. Establishing mitigation measures requires determining how much mitigation is required – i.e., setting a limit, or establishing a standard, that quantifies the amount of GHG emissions that will adversely affect the environment. Some may also argue that the Commission has unilaterally established mitigation in other contexts, including wetlands, soil conservation, and noise. These examples, however, are distinguishable. Congress did not exclusively assign the authority to establish avoidance or restoration measures for mitigating effects on wetlands or soil to a specific agency. The Corps and the EPA developed a wetlands mitigation bank program pursuant to section 404 of the Clean Water Act.[49] Congress endorsed such mitigation.[50] As for noise, the Clean Air Act assigns the EPA Administrator authority over determining the level of noise that amounts to a public nuisance and requires federal agencies to consult with the EPA when its actions exceed the public nuisance standard.[51] The Commission complies with the Clean Air Act by

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[47] National Climate Program Act, S. 1980, 95th Cong. (1977).

[48] CONGRESSIONAL RESEARCH SERVICE, MARKET-BASED GREENHOUSE GAS EMISSION REDUCTION LEGISLATION: 108TH THROUGH 116TH CONGRESSES at 3 (Oct. 23, 2019), https://fas.org/sgp/crs/misc/R45472.pdfhttps://fas.org/sgp/crs/misc/R45472.pdf. Likewise, the CEQ issued guidance on the consideration of GHG emissions in 2010, 2014, 2016, and 2019. None of those documents require, let alone recommend, that an agency establish a carbon emissions fee or tax.

[49] 33 U.S.C. § 1344 (2018).

[50] *See* Water Resources Development Act, Pub. L. 110-114, § 2036(c), 121 Stat. 1041, 1094 (2007); National Defense Authorization Act, Pub. L. 108-136, § 314, 117 Stat. 1392, 1430 (2004); Transportation Equity Act for the 21st Century, Pub. L. 105-178, § 103 (b)(6)(M), 112 Stat. 107, 133 (1998); Water Resources Development Act of 1990, Pub. L. 101-640, § (a)(18)(C), 104 Stat. 4604, 4609 (1990).

[51] 42 U.S.C. § 7641(c) ("In any case where any Federal department or agency is carrying out or sponsoring any activity resulting in noise which the Administrator

requiring project noise levels in certain areas to not exceed 55 dBA Ldn, as required by EPA's guidelines.[52]

27. Accordingly, there is no support that the Commission can use its NGA section 3 authority to establish measures to mitigate GHG emissions from LNG facilities.

III. Conclusion

28. In sum, the Commission has no reasoned basis for determining whether GHG emissions are significant that would satisfy the Commission's APA obligations. Nor does the Commission have the ability to establish measures to mitigate GHG emissions. Pursuant to the Clean Air Act, Congress exclusively assigned authority to regulate emissions to the EPA and the States.

29. I recognize that some believe the Commission should do more to address climate change. The Commission, an energy agency with a limited statutory authority, is not the appropriate authority to establish a new regulatory regime.

For these reasons, I respectfully concur.

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Bernard L. McNamee

determines amounts to a public nuisance or is otherwise objectionable, such department or agency shall consult with the Administrator to determine possible means of abating such noise.").

[52] *See Williams Gas Pipelines Cent., Inc.*, 93 FERC ¶ 61,159, at 61,531-52 (2000).