



December 10, 2020

Via Electronic Mail

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Re: National Parks Conservation Association, Center for Biological Diversity, and Northern Alaska Environmental Center Comments on Preliminary Prevention of Significant Deterioration Permit No. AQ1539CPT01, Proposed in response to Application from Alaska Gasline Development Corporation to Construct a Liquefaction Plant in Nikiski, Alaska

Dear Mr. Jones,

Please find enclosed the comments submitted on draft Construction Permit No. AQ1539CPT01, in regards to the application from Alaska Gasline Development Corporation to construct a Liquefaction Plant in Nikiski, Alaska, on behalf of National Parks Conservation Association, Center for Biological Diversity, and Northern Alaska Environmental Center. The enclosures were submitted at the website you provided earlier for this purpose: <https://drop.state.ak.us/drop/>. The list of enclosure is attached to these comments.

We appreciate the Department's consideration of these comments. Please do not hesitate to contact me with any questions.

Sincerely,



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Enclosures

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I. Introduction

NPCA is a nonprofit and nonpartisan organization working to protect and enhance America's National Park System for present and future generations. The National Parks Conservation Association was founded in 1919, and today has more than 1.3 million members and supporters. It is headquartered in Washington, D.C., and has various regional and field offices, including an Alaska Regional office in Anchorage. Among other things, it works to ensure that national parks and the air, waters and wildlife that moves through them are protected.

The Center for Biological Diversity is a national, nonprofit organization with more than 1.7 million members and online activists. The Center works through science, law, and advocacy to secure a future for all species, great and small, hovering on the brink of extinction, with a focus on protecting the lands, waters, and climate that species need to survive.

The Northern Alaska Environmental Center (Northern Center), founded in 1971, is a small nonprofit organization dedicated to the conservation of the environment and sustainable resource stewardship in Interior and Arctic Alaska through education and advocacy. Based in Fairbanks, Alaska, the Northern Center has over 900 members and more than 4000 supporters online. Since its inception, the Northern Center has been the only local nonprofit environmental conservation organization dedicated to protecting the Arctic.

On September 11, 2020, the Alaska Department of Environmental Conservation (ADEC) proposed approval of a Clean Air Act Prevention of Significant Deterioration (PSD) permit to the Alaska Gasline Development Corporation (AGDC), which would allow construction of a Liquefaction plant in Nikiski, Alaska that would cool, process, store, and load liquefied natural gas (LNG) for shipment of Alaska's North Slope natural gas to outside markets. ADEC also classified the plant as a major source of Hazardous Air Pollutants for formaldehyde and ethylbenzene.

NPCA prepared these comments in coordination with the reports prepared by Mr. Howard Gebhart¹ and Ms. Victoria Stamper.² Mr. Gebhart is an air quality meteorologist with 40 years of experience in air quality permitting, specializing in air dispersion modeling. Ms. Stamper is an independent air quality consultant with over 30 years of experience in the field of air pollution control and extensive experience in new source review permitting. The comments in these two reports are incorporated by reference as a part of these comments.

II. Regulatory Framework and Background

¹ See enclosed report entitled "Technical Comments on Alaska LNG Project - Liquefaction plant PSD Permit," (Dec. 6, 2020) ("Gebhart Report"), prepared by Mr. Howard Gebhart. Mr. Gebhart's Curriculum Vitae is enclosed.

² See enclosed report entitled "Comments on the Best Available Control Technology (BACT) Analysis of the Alaska Department of Environmental Conservation's Proposed Air Quality Construction Permit for the Alaska Gasline Development Corporation Liquefaction Plant to be Located in Nikiski, Alaska," (Dec. 8, 2020) (Stamper Report), prepared by Victoria Stamper. Ms. Stamper's Curriculum Vitae is in Attachment A to that report.

The Clean Air Act (CAA) aims to “protect and enhance the quality of the Nation’s air resources.”³ To this end, the Act employs a variety of programs—including the Prevention of Significant Deterioration (PSD) program, which governs air pollution in areas where the air quality meets or is cleaner than the National Ambient Air Quality Standards (NAAQS).⁴ The PSD provisions were added to the CAA in 1977 to focus on “facilities which, due to their size, are financially able to bear . . . substantial regulatory costs . . . and which, as a group, are primarily responsible for emissions of the deleterious pollutants that befoul our nation’s air.”⁵ Under the PSD program, owners or operators of major emitting facilities in attainment or unclassifiable areas must obtain a PSD permit prior to the construction of that facility.⁶ The ultimate purpose of the PSD program is to maintain air quality better than the NAAQS and Congress repeatedly emphasized that NAAQS alone were insufficient to protect public health and welfare.⁷ For example, the

Senate Report emphasized the ‘shortcomings and limitations’ of the ambient standards—they do not provide an adequate margin of safety on health impacts; they are based on a false assumption that no-effects threshold levels exist; they do not adequately protect against genetic mutations, birth defects, cancer, or diseases caused by long-term chronic exposures or periodic short-term peak concentrations, and hazards due to derivative pollutants and to cumulative or synergistic impacts of various pollutants; and they do not adequately protect against crop damage and acid rain.⁸

Congress designed the Prevention of Significant Deterioration program with the goal of “assur[ing] that any decision to permit increased air pollution . . . is made *only after careful evaluation of all the consequences of such a decision*.”⁹ The PSD program prohibits the construction of any “major emitting facility” unless it obtains a pre-construction permit ensuring that the project is subject to the best available control technology (BACT) for each regulated pollutant;¹⁰ that the project will not cause or contribute to a violation of either NAAQS or so-called PSD “increments” approaching the NAAQS; and that the project will satisfy all other applicable requirements of the Act.¹¹ Determination of BACT is made “on a case-by-case basis,

³ 42 U.S.C. § 7401.

⁴ 42 U.S.C. § 7470.

⁵ *Ala. Power Co. v. Costle*, 636 F.2d 323, 353 (D.C. Cir. 1980)(“Alabama Power”).

⁶ 42 U.S.C. § 7475.

⁷ *Hawaiian Elec. Co. v. U.S. E.P.A.*, 723 F.2d 1440, 1446-7 (9th Cir. 1984)(“Hawaiian Elec.”).

⁸ *Id.*, citing, H.R. Rep. No. 294, 95th Cong., 1st Sess. 105–132, *reprinted in* 1977 U.S. Code Cong. & Ad. News 1183–1211; *see also* Statement by Senator Muskie in *A Legislative History of the Clean Air Act Amendments of 1977*, 95th Cong., 2d Sess. No. 16 (1979), vol. 3, pp. 1032–1035. “The non-degradation amendment is intended to help reduce overall emissions and thus provide protection against these kinds of adverse impacts.” *Legislative History, supra*, at 728.

⁹ 42 U.S.C. § 7470 (emphasis added). In furtherance of that goal, EPA permitting guidance requires state agencies to make independent determinations about necessary emissions controls and not to rely solely on applicant information. EPA, New Source Review Workshop Manual, at B.53-54 (Draft Oct. 1990) (“NSR Workshop Manual”), available at <https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf> (last visited Nov. 30, 2020).

¹⁰ All new source applicants must install the “best available control technology” (“BACT”) to reduce air pollution. *Id.* § 7475(a)(4). Determination of the best available control technology is made “on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs.” *Id.* § 7479(3). *Citizens for Clean Air v. U.S. E.P.A.*, 959 F.2d 839, 842 (9th Cir. 1992)(“Citizens”).

¹¹ 42 U.S.C. § 7475.

taking into account energy, environmental, and economic impacts and other costs.”¹² “The BACT requirement consists of ‘an emission limitation based on the maximum degree of reduction of each [regulated] pollutant’ that EPA [or a state] determines is achievable ‘through application of production processes and available methods, systems, and techniques’ in view of ‘energy, environmental, and economic impacts and other costs.’”¹³

Congress found that it was important to reduce pollution levels below those mandated by the standards and that the best means of doing so was to require the installation of BACT on all sources which would otherwise increase pollution.¹⁴

In addition to the BACT analysis, a new source seeking a PSD permit must also complete an air quality analysis. The purpose of this analysis is to ensure that the emissions from the proposed facility, in conjunction with the emissions from other sources, will not cause or contribute to a violation of the national ambient air quality standards or the PSD increment limits. The national air standards place a ceiling on the total concentration of certain pollutants in the atmosphere. The PSD increments, on the other hand, place a limitation on the amount a source may increase the concentration of a pollutant over the baseline. The amount of increase allowed varies based on the location of the proposed source. Locations are divided into three categories. Class I allows the smallest increase in pollution levels and covers specific national parks, wilderness areas and Tribal lands. Class II allows a moderate increase and applies to areas considered normal growth areas. Class III areas can have the largest increment and are areas where the state or local authority foresees a greater amount of industrial development, there are no Class III areas. States must model the air quality impacts of a proposed new source of air pollution according to federal regulations before they can issue a permit to that source. These regulations require that a state model the air quality impacts of a new source using meteorological data that is “representative” of the proposed source site.¹⁵ The meteorological data is used to predict how emissions will behave once emitted from a source. A state also must model all emissions at the levels allowed in the proposed permit,¹⁶ along with other model and emission requirements specified in the state’s rules, which are approved by EPA for this purpose.

States can seek federal approval to administer the PSD permit program through a “State Implementation Plan,” or SIP. To gain EPA approval, a SIP must “include enforceable emission limitations and other control measures, means, or techniques . . . as may be necessary or appropriate to meet the applicable [Clean Air Act] requirements” and to “assure that national ambient air quality standards are achieved.”¹⁷ SIPs also must “contain emission limitations and such other measures as may be necessary . . . to prevent significant deterioration of air quality.”¹⁸ While EPA approves state programs, it retains oversight authority over implementation by a state.¹⁹

¹² *Id.* § 7479(3).

¹³ 42 U.S.C. § 7479(3); *Sierra Club v. U.S. E.P.A.*, 762 F.3d 971, 974 (9th Cir. 2014).

¹⁴ *Hawaiian Elec.* at 1447.

¹⁵ 40 C.F.R. Pt. 51, App. W at 8.4.1(b) (“EPA Guideline on Air Quality Models”).

¹⁶ *Id.* at Table 8-2.

¹⁷ 42 U.S.C. § 7410(a)(2).

¹⁸ 42 U.S.C. § 7471; *see also* 40 C.F.R. §§ 51.166, 52.21.

¹⁹ *Alaska Dep’t of Env’tl. Conservation v. E.P.A.*, 540 U.S. 461 (2004) (affirming EPA’s reversal of a state permitting decision) (“ADEC”).

Alaska administers the PSD program through an EPA-approved SIP.²⁰ Like its federal counterpart, Alaska’s PSD program requires would-be permittees to analyze all potential impact of their proposal on air quality, visibility, soils, and vegetation. It also adopts the five-step “top down” BACT analysis propounded by the EPA, further developed by its Environmental Appeals Board,²¹ and upheld by the federal courts.²² The ADEC’s Preliminary “Technical Analysis Report” for the terms and conditions of proposed Construction Permit AQ1539CPT01 explains that “[t]he Department based the BACT review on the five-step top-down approach set forth in” EPA’s 1996 Federal Register notice.²³ EPA’s 1996, notice explained that “[s]ince late 1987 EPA has recommended a specific process for determining BACT.”²⁴ Specifically, “[t]he EPA’s recommended methodology for determining BACT is described in detail in the 1990 Draft NSR Workshop Manual.”²⁵ The five-step top-down process includes:

Figure 1. The Clean Air Act’s BACT Five-Step Process.²⁶

Step 1: Identify All Control Technologies. ²⁷	A comprehensive list of control technologies must be identified, including technologies required under lowest achievable emission rate determinations.
Step 2: Eliminate Technically Infeasible Options.	A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.
Step 3: Rank Remaining Control Technologies by	Should include: <ul style="list-style-type: none"> • control effectiveness (percent pollutant removed); • expected emission rate (tons per year); • expected emission reduction (tons per year);

²⁰ When EPA approves a state SIP, it incorporates the relevant state law into the Code of Federal Regulations by reference. ADEC’s EPA-approved PSD SIP program has been revised over the years, and in addition to some provisions that occur in ADEC regulations and State statute, ADEC’s SIP includes EPA PSD regulations that were adopted by reference in the State’s rules and State statute. Furthermore, ADEC and the State legislature adopted portions of EPA’s PSD regulations on different years.

²¹ The EPA’s Environmental Appeals Board adjudicates appeals from federally-issued PSD permits (as well as state permits issued under federal delegation) and has developed a body of case law on BACT requirements. Because state PSD programs must “implement standards and limitations as stringent as those set by the EPA” and must be interpreted “with an eye to furthering the goals of the [federal] PSD program,” agencies and courts turn to the Board’s rulings in applying their respective state PSD programs. *Utah Chapter of the Sierra Club v. Air Quality Board*, 226 P.3d 719, 727, 733 (Utah 2009). In sum, a permitting authority is required to follow the EPA’s analytical permitting framework unless it has clearly articulated (and provided a statutory foundation for) its own alternative. *Cash Creek Generation LLC*, Petition No. IV-2008-1, 9 (Dec. 15, 2009), available at https://www.epa.gov/sites/production/files/2015-08/documents/cashcreek_response2008.pdf (“Cash Creek I”).

²² See generally *Sierra Club v. Environmental Protection Agency*, 499 F.3d 653 (7th Cir. 2007).

²³ ADEC, “Preliminary Technical Analysis Report For the terms and conditions of Construction Permit AQ1539CPT01,” at 1 (Sept. 11, 2020) (“PreTAR”); 61 Fed. Reg. 38250 (July 23, 1996).

²⁴ *Id.* at 38272.

²⁵ NSR Workshop Manual, at B.53-54.

²⁶ *Id.* at B-6.

²⁷ Control technologies “are those technologies that have ‘a practical potential for application to the emissions unit and the regulated pollutant under evaluation.’” *Helping Hand Tools v. U.S. Env’tl. Prot. Agency*, 848 F.3d 1185, 1190 (9th Cir. 2016)(“Helping Hand”) (quoting, NSR Workshop Manual, at B.5). Generally, under federal law the failure to consider available alternative control technologies (also referred to as “control alternatives”) in BACT analysis “constitutes clear error.” *Id.* at 1194.

Control Effectiveness.	<ul style="list-style-type: none"> • energy impacts (BTU, kWh); • environmental impacts (other media and the emissions of toxic and hazardous air emissions); and • economic impacts (total cost effectiveness, incremental cost effectiveness).
Step 4: Evaluate Most Effective Controls and Document Results.	Case-by-case consideration of energy, environmental, and economic impacts. If top option is not selected as BACT, evaluate next most effective control option.
Step 5: Select BACT.	Most effective option not rejected is BACT.

Failing to conduct a complete BACT analysis, including failure to consider all potentially applicable control alternatives, is an abuse of the permitting authority's discretion.²⁸ A state is only authorized to issue permits to sources that "will not cause, or contribute to, air pollution in excess of any . . . maximum allowable increase or maximum allowable concentration for any pollutant" or any National Ambient Air Quality Standard.²⁹

Additionally, another feature of the PSD program is that all "new sources must meet 'New Source Performance Standards,' which impose various emissions limitations."³⁰ "EPA periodically promulgates New Source Performance Standards under its rulemaking authority."³¹ Finally, regulations for the PSD program require notice, a comment period, and a public hearing on applications for new sources of air pollution.

One of the stated purposes of the PSD program is "to preserve, protect, and enhance the air quality in national parks [and] national wilderness areas."³² There are 156 federally designated Class I area national parks and wilderness areas under Act,³³ that are entitled to additional protection under the PSD program.³⁴ The U.S. Fish and Wildlife Service (USFWS) and the National Park Service (NPS) are the Federal Land Managers (FLMs) charged with direct responsibility to protect the air quality and related values (including visibility) of Alaska's Class I areas and Class II nationally designated protected areas. FLMs have an affirmative obligation to consider, in consultation with the EPA [and the permitting authority], whether proposed industrial facilities would have an adverse impact on these values.³⁵ Moreover, the Mission of the USFWS Air Quality Program is to "[p]rotect and enhance air quality in support of ecosystem management in the National Wildlife Refuge System, in an effort to create a Refuge System free of impacts from human-caused air pollution and promote biological integrity, diversity, and

²⁸ See *Louisville Gas & Electric Co.*, 2009 WL 7698409, 13 (EPA 2009) (citing *Prairie State Generation*, 13 E.A.D. ___, PSD Appeal No. 05-05, slip op. at 19 (EPA 2006); *Knauf Fiber Glass*, 8 E.A.D. 121, 142 (EPA 1999) ("Knauf I"); *Masonite Corp.*, 5 E.A.D. 551, 568-569 (E.A.B. 1994) ("Masonite").

²⁹ 42 U.S.C. § 7475(a)(3).

³⁰ *Citizens* at 842, *Id.* § 7411(a), (f).

³¹ *Id.* § 7411(b)(1)(B).

³² 42 U.S.C. § 7470(2).

³³ 42 U.S.C. § 7472(a).

³⁴ A number of Tribal lands have been redesignated as Class I areas, although these newer designations are not considered "federally mandated."

³⁵ 42 U.S.C. § 7475(c).

environmental health of the system.”³⁶ The NPS’ Air Resource Division, “together with parks and other National Park Service offices, monitors air quality conditions in parks and conducts research to better understand the sources and effects of air pollution. Additionally, because most pollution in national parks comes from outside park boundaries, the Air Resources Division facilitates NPS partnerships with air regulators, industries, and other stakeholders to reduce air pollution. Less pollution means cleaner air, clearer views and healthier ecosystems for parks and nearby communities.”³⁷

The USFWS has direct responsibility for managing wilderness and refuges, under its CAA responsibilities and the specific protections afforded these special places by Congress. The Tuxedni Wilderness³⁸ within the Alaska Maritime National Wildlife Refuge (NWR) is designated a Class I area, and the Arctic, Kanuti, Yukon Flats, Koyukuk, Selawik, Nowitna, Kenai, Kodiak, and Alaska Maritime NWRs are Class II sensitive areas.³⁹ The USFWS is responsible for land management within all of these NWRs, a portion of which would be within 186.4 miles of the AGDC’s proposed facilities.⁴⁰

The NPS manages its lands to protect and preserve natural and cultural resources unimpaired for the enjoyment of future generations. The NPS is responsible for management of lands within the Denali National Park and Preserve (DNPP), Lake Clark National Park and Preserve (NPP), Kenai Fjords National Park, and Gates of the Arctic NPP, all of which would be

³⁶ USFWS, “Mission of the U.S. Fish and Wildlife Service Air Quality Program,” available at <https://www.fws.gov/refuges/AirQuality/index.html>, which involves “[p]rotecting air quality, and resources sensitive to air quality, in the National Wildlife Refuge System is a complex task that includes: active research and monitoring about the amount and effects of pollution in FWS areas; advocacy for pollution controls when they are likely to affect FWS refuge areas; and ensuring there is an active advocate of clean healthy air across the National Wildlife Refuge System.” *Id.*

³⁷ NPS, Air Resource Division, “What We Do,” available at <https://www.nps.gov/orgs/1971/whatwedo.htm>.

³⁸ USFWS, The Tuxedni Wilderness, Alaska Maritime National Wildlife Refuge (NWR) – Tuxedni Wilderness (Refuge area and Class I Designation), available at <https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/>.

³⁹ USFWS, Air Quality in Refuges, <https://www.fws.gov/refuges/AirQuality/ARIS.html>. (The Air Quality in Refuges pages provide information on refuges and wilderness areas managed by the U.S. Fish and Wildlife Service (FWS) as well as Inventory & Monitoring (I & M) networks. Air Quality in Refuges pages identifies air quality related values for Class I air quality areas and provides guidance on analysis for evaluating impacts to air quality related values. These Air Quality in Refuge pages maintains information on 21 FWS Class I areas and other FWS Class II sensitive areas.)

⁴⁰ Per the Alaska National Interest Lands Conservation Act (ANILCA) 303(1)(B), the purposes for which the Alaska Maritime NWR, including Tuxedni NWR [ANILCA 303(1)(v) Gulf of Alaska (GOA) Unit], Arctic NWR (ANWR) [ANILCA 303(2)(B)]; Kanuti NWR [ANILCA 302(4)(B)]; Kenai NWR [ANILCA 303(4)(B)]; Kodiak NWR [ANILCA 303(5)(B)]; Koyukuk NWR [ANILCA 302(5)(B)]; Nowitna NWR [ANILCA 302(6)(B)]; Selawik NWR [ANILCA 302(7)(B)]; and, Yukon Flats NWR [ANILCA 302(9)(B) and 303(7)(B)] were established and managed are to: conserve fish and wildlife populations and habitats in their natural diversity; fulfill the international treaty obligations of the United States with respect to fish and wildlife and their habitats; provide the opportunity for continued subsistence uses by local residents; provide a program of national and international scientific research on marine resources; and ensure, to the maximum extent practicable, water quality and necessary water quality within the refuge. These purposes are integrated into Comprehensive Conservation Plans applicable to each refuge. In addition to ANILCA, each refuge is administered under the National Wildlife Refuge System Administration Act of 1966, as amended by the National Wildlife Refuge System Improvement Act of 1997 (16 U.S.C. §§ 668dd-668ee), which serves as the “organic act” for the National Wildlife Refuge System. The National Wildlife Refuge System Improvement Act provides a foundation for the USFWS’ biological integrity, diversity, and environmental health policy. Finally, many refuges in Alaska have portions that are congressionally designated as wilderness or possess wilderness characteristics under the Wilderness Act of 1964.

within 186.4 miles of Project facilities. The DNPP is designated a Class I area, while Lake Clark, Kenai Fjords, and Gates of the Arctic are designated as Class II nationally designated protected areas.

The NPS and USFWS describe the following *existing*, adverse impacts on visibility and AQRVs, as well as sensitive ozone species⁴¹ at some of these impacted parks, preserves and wilderness areas as follows:

- **Lake Clark National Park and Preserve.** Lake Clark National Park and Preserve protects approximately 4 million acres of undisturbed public land characterized by scenic vistas such as; rugged mountain peaks and spires, glaciers, an ocean coast, deep valleys and lakes, high tundra, wild rivers, and a wide cross-section of flora and fauna. Most visitors to the park and preserve experience scenic vistas by flying in by small airplane and either hiking, boating, fishing, or camping in the area. Scenic vistas are for the most part intact, but are threatened by development activities outside of the park. Pollutant haze may obscure visibility at the wilderness area part of the time.⁴² Additionally, Although Lake Clark is mostly uninhabited wilderness concern has been growing about air quality in areas of Lake Clark National Park and Preserve, particularly along the coast.⁴³
- **Tuxedni National Wildlife Refuge.**⁴⁴ Designated a Class I area in 1977, this area consists of “[t]wo islands at the mouth of Tuxedni Bay (Chisik and Duck) were established as a refuge for seabirds, bald eagles and peregrine falcons in 1909, as shown in green in the map to the right. ... Other species protected in this Wilderness Area include large colonies of sea birds, black-legged kittiwakes, horned puffins, common murre, pigeon guillemots, and glaucous-winged gulls. Other species include several endangered or threatened species such as short tailed albatross, Eskimo curlew, leatherback sea turtle, Steller western and eastern pop. Sea-lion, bowhead whale, humpback whale, spectacled eider, Steller’s AK breeding populations, lynx, and otter.”⁴⁵ Potential air pollution threats to Tuxedni include oil and gas development in Alaska, especially in the Cook Inlet,⁴⁶ Human

⁴¹ Ozone Sensitive Species: The NPS maintains a compilation of ozone sensitive species. Its compilation shows there are numerous ozone sensitive species at several of these special areas, including: LACL; KEFJ; DNPP; GAAR; and KEFJ. NPS, “Ozone Sensitive Species by Park,” available at <https://irma.nps.gov/NPSpecies/Reports/Systemwide/Ozone-sensitive%20Species%20by%20Park>. (enclosed)

⁴² NPS, Lake Clark NPP, Environmental Factors, available at <https://www.nps.gov/lacl/learn/nature/environmentalfactors.htm>.

⁴³ *Id.*

⁴⁴ There is an IMPROVE sampler at the Refuge. See *Interagency Monitoring of Protected Visual Environments*, IMPROVE Program Overview, available at <http://vista.cira.colostate.edu/Improve/improve-program/> (enclosed).

⁴⁵ USFWS, Tuxedni Wilderness, available at <https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/>.

⁴⁶ *Id.* (Discussing the Tuxedni NWR adjacent to Lake Clark); see also USFWS Air Quality Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness, available at <https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/AirQuality.html>; USFWS AQRVs Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness, available at <https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/AQRV.html>; USFWS Air Pollution Impacts (Visibility) Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness available at

produced haze occasionally impairs scenic vistas at the refuge.⁴⁷ This degradation results in the reduction of the average natural visual range from about 150 miles (without the effects of pollution) to about 125 miles (with the effects of pollution) at the refuge. On the most polluted days the average visual range has been reduced to 68 miles on the most polluted days (20% highest pollution days). The U.S. Fish and Wildlife Service has begun monitoring air quality in the Refuge in cooperation with the National Park Service and the State of Alaska.⁴⁸ “If the Tuxedni Wilderness is not protected, unique wildlife and scenic values could be threatened or lost. The FWS hopes to preserve and protect this special area of wilderness for future generations.”⁴⁹

- Denali National Park and Preserve.** The Park and Preserve include more than 6 million acres, which in 2019 had more than 600,000 visitors.⁵⁰ Many of its visitors travel the 92-miles road, which parallels the Alaska Range and travels through low valleys and high mountain passes. It is the only road in the park. Along its route, beautiful landscapes can be seen at every turn, and there are many opportunities to view Denali.⁵¹ Pollution reduces the average natural visual range from about 165 miles (without the effects of pollution) to about 160 miles at the park. Reduction of the visual range to below 105 miles is experienced on very hazy days.⁵² DNPP is also particularly susceptible to the accumulation of persistent organic pollutants (POPs) and other toxic airborne contaminants. Episodes of high ozone concentrations have been documented in the park, but thus far, these episodes are relatively short in duration.⁵³ Further, while ozone effects have not been documented in the park, several park species, including *Salix scouleriana* (Scouler’s willow) and *Populus tremuloides* (quaking aspen), are known to be sensitive to ozone.⁵⁴ The risk from either acidification or fertilization is considered low at DNPP because rates of nitrogen and sulfur deposition are very low.⁵⁵ However, certain vegetation communities in the park, including wetlands and arctic vegetation, are known to be vulnerable to excess nitrogen deposition.⁵⁶ If nitrogen deposition increases significantly, these plant communities could be affected. Certain lichen species that occur in the park are

<https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html>; USFWS Air Pollution Impacts (Nitrogen & Sulfur) Alaska Maritime National Wildlife Refuge (NWR) - Tuxedni Wilderness available at <https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html>; USFWS Air Pollution Impacts (Ozone) Alaska Maritime National Wildlife Refuge (NWR) – Tuxedni Wilderness available at <https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Impacts.html>; USFWS Monitoring Alaska Maritime National Wildlife Refuge (NWR) – Tuxedni Wilderness available at <https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/Monitoring.html>.

⁴⁷ *Id.*

⁴⁸ *Id.*

⁴⁹ USFWS, Tuxedni Wilderness, available at <https://www.fws.gov/refuges/AirQuality/ARIS/TUXE/>.

⁵⁰ NPS, Denali, Park Statistics, available at <https://www.nps.gov/dena/learn/management/statistics.htm>.

⁵¹ NPS, Introduction to Denali, available at <https://www.nps.gov/dena/planyourvisit/visiting-denali.htm>.

⁵² NPS, Park Air Profiles, Denali National Park & Preserve, available at <https://www.nps.gov/articles/airprofiles-dena.htm>.

⁵³ *Id.*

⁵⁴ *Id.*

⁵⁵ *Id.*

⁵⁶ *Id.*

known to be sensitive to air pollution, including the globally rare *Erioderma pedicellatum*.⁵⁷

Moreover, in light of “potential nitrogen deposition impact concerns in Denali National Park” including “potential declines in lichen communities in the south end of the park that are an important component of park ecosystems, as well as potential impacts to a globally rare lichen species that is listed as critically endangered by the International Union for Conservation of Nature (IUCN),” the NPS recommended that SCR controls for NO_x BACT may be economically feasible and is necessary to address potential nitrogen deposition impact concerns in Denali National Park.⁵⁸

- **Kenai Fjords National Park and Lake Clark National Park and Preserve.** NPS published a report in 2016,⁵⁹ which identified several concerns regarding AQRVs at this two areas. For example, in assessing nutrient nitrogen enrichment, the study explained that “[e]ctomycorrhizal fungal (EMF) communities are important in tree nutrition, and EMF trees tend to be dominant in N-limited forest ecosystems.”⁶⁰ The report further explained that earlier studies found “[p]rogressive decline in EMF species richness in Alaskan coniferous forest (white spruce [*Picea glauca*] dominant) occurred along a local N deposition gradient, from 1 to 20 kg N/ha/yr, downwind from a fertilizer facility,” which is

⁵⁷ *Id.* See also, Nelson, P., Walton, J. and Roland, C. “*Erioderma pedicellatum* (Hue) P. M. Jorg., New to the United States and Western North America, Discovered in Denali National Park and Preserve and Denali State Park, Alaska,” *Evansia* 25: 19–23 (2009), available at https://www.researchgate.net/publication/259742473_Erioderma_pedicellatum_Hue_PM_Jorg_New_to_the_United_States_and_Western_North_America_Discovered_in_Denali_National_Park_and_Preserve_and_Denali_State_Park_Alaska/link/0deec52d89f551f5c8000000/download.

⁵⁸ NPS Email to ADEC (Dec. 4, 2020) (included as an enclosure to these comments). The NPS further explains that “[t]his species was only recently discovered at several sites within and near Denali NP. These populations are the only known occurrences within the US and western North America.” *Id.*

⁵⁹ Sullivan, T. J., “Air quality related values (AQRVs) for Southwest Alaska Network (SWAN) parks: Effects from ozone; visibility reducing particles; and atmospheric deposition of acids, nutrients and toxics,” Natural Resource Report NPS/SWAN/NRR—2016/1204 (2016). National Park Service, Fort Collins, Colorado, available at <https://irma.nps.gov/DataStore/DownloadFile/548903> (Sullivan). See also Flanagan, C., “Contaminants study provides window onto airborne toxic impacts in western U.S. and Alaska national parks. Results and implications of the Western Airborne contaminants Assessment Project,” *Park Science* 26(2):58-63 (2009), available at <https://irma.nps.gov/DataStore/Reference/Profile/2201538>; Flanagan Pritz, C.M., J.E. Schrlau, S.L. Massey Simonich, and T.F. Blett, “Contaminants of emerging concern in fish from western U.S. and Alaskan National Parks — spatial distribution and health thresholds,” *J. Am. Water Resour. Assoc.* 50(2):309-323 (2014), available at <https://onlinelibrary.wiley.com/doi/epdf/10.1111/jawr.12168> (included as an enclosure with these comments); Mölders, N., S.E. Porter, C.F. Cahill, and G.A. Grell, “Influence of ship emissions on air quality and input of contaminants in southern Alaska National Parks and Wilderness Areas during the 2006 tourist season,” *Atmos. Environ.* 44(11):1400-1413 (2010), available at <https://www.sciencedirect.com/science/article/abs/pii/S1352231010001044?via%3Dihub> (included as an enclosure with these comments); Munk, L., B. Cohn, and B. Finney, “Historical Trace Element Trends Recorded in Lake Sediment Cores from the Southwest Alaska Network of Parks. Natural Resources Technical Report,” NPS/SWAN/NRTR-2010/395 (2010). National Park Service, Fort Collins, CO, available at <https://www.sciencedirect.com/science/article/abs/pii/S1352231010001044?via%3Dihub> (included as an enclosure with these comments).

⁶⁰ *Id.* at 9.

nearby the proposed Liquefaction Plant, that was shut down at the time of the study, and is located on the Kenai Peninsula west of KEFJ.”⁶¹ (Lilleskov et al. 2001, Lilleskov et al. 2002). Additionally, regarding ozone injury to vegetation, KEFJ contains “quaking aspen (*Populus tremuloides*), thought to be among the most sensitive hardwood tree species to O₃ damage.”⁶² LACL also contains two species sensitive to O₃ damage: FILL IN.⁶³ Furthermore, LACL is impacted by “inland transport of pollutants from ship traffic,” which is enhanced by “the channeling of east winds between the Kenai Peninsula and Kodiak Island... .”⁶⁴ Ecosystem ranking of acidification at LACL ranked “Very High,” indicating a sensitivity to acidification.⁶⁵ LACL is located about 30 miles from the Tuxedni Wilderness, which is “monitored by the Interagency Monitoring of Protected Visual Environments Network (IMPROVE).”⁶⁶ Thus that “monitoring site is considered by IMPROVE to be representative of” LACL because it is an area “within 60 mi (100 km) and 425 ft (130 m) in elevation of” Tuxedni.⁶⁷ Therefore, the threats and degradation at Tuxedni described above are also present at LACL. Furthermore, a study that measured airborne Synthetic Organic Carbon contaminant concentrations in fish collected from lakes in LACL, “thresholds to protect kingfisher were exceeded in some fish from some lakes for chlordane and P,P’-DDE.”⁶⁸ Additionally, mercury concentrations in fish from LACL’s “Lake Kontrashibuna and Lake Clark” were found to exceeding the benchmark for

⁶¹ *Id.*, citing Lilleskov, E.A., T.J. Fahey, and G.M. Lovett, “Ectomycorrhizal fungal aboveground community change over an atmospheric nitrogen deposition gradient,” *Ecol. Appl.* 11(2):397-410 (2001), available at [https://doi.org/10.1890/1051-0761\(2001\)011\[0397:EFACCO\]2.0.CO;2](https://doi.org/10.1890/1051-0761(2001)011[0397:EFACCO]2.0.CO;2), (included as an enclosure with these comments); Lilleskov, E.A., T.J. Fahey, T.R. Horton, and G.M. Lovett, “Belowground ectomycorrhizal fungal community change over a nitrogen deposition gradient in Alaska,” *Ecology* 83(1):104-115 (2002), available at [https://doi.org/10.1890/0012-9658\(2002\)083\[0104:BEFCCO\]2.0.CO;2](https://doi.org/10.1890/0012-9658(2002)083[0104:BEFCCO]2.0.CO;2), included as an enclosure with these comments, checking to see if NPCA can obtain. Although the fertilizer facility was shutdown at the time of the study, ADEC is in the process of reviewing a PSD application submitted by Agrium U.S. Inc. for their Kenai Nitrogen Operations (KNO) Facility. There are two ammonia and two urea plants at Agrium’s KNO facility and ADEC’s proposed permit would authorize the restart of one ammonia and one urea plant. ADEC’s recently proposed PSD permit documents are included as enclosures with these comments. Finally, ADEC’s January 6, 2016, Technical Analysis Report, which is the only document for Liquefaction Plant available on ADEC’s website is also included as an enclosure with these comments).

⁶² Sullivan at 12.

⁶³ NPS, “Ozone Sensitive Species by Park,” available at <https://irma.nps.gov/NPSpecies/Reports/Systemwide/Ozone-sensitive%20Species%20by%20Park>.

⁶⁴ *Id.* at 3.

⁶⁵ *Id.* at 4. The study examined information available in 2006, and noted at that time “[a]lthough aquatic and/or terrestrial resources in some SWAN [Southwest Alaska Network] parks may indeed be sensitive to acidification, this is not an important concern at this time in view of the very low levels of S and N emissions and deposition within and near this network.” These impacts could change with the proposed approval of the fertilizer facility, *supra* n.54.

⁶⁶ *Id.* at 13.

⁶⁷ *Id.*

⁶⁸ *Id.* at 19, citing Simonich, S.L.M., J. Schrlau, C. Flanagan, and T. Blett, “Chemical Burdens in Fish from Alaskan Parks Compared to Human and Wildlife Health Consumption Thresholds” (2013), available at http://depts.washington.edu/pnwcesu/reports/J8W07100027_Final_Report.pdf. Additionally, Sullivan explain “fisheries biologists have been collecting and analyzing fish tissue samples from selected lakes in LACL and KATM. Analyses include Hg, arsenic, copper, selenium, lead, and zinc every 5 years and for certain POPs every 10-15 years. Baseline sampling was conducted in 2011 for lake trout, northern pike (*Esox lucius*), and slimy sculpin (*Cottus cognatus*); Data collected on future sampling occasions will shed light on potential trends in bioaccumulation of toxics in aquatic receptors.” *Id.* at 33 (internal citations omitted).

Figure 2. Class I and II Areas and the Proposed AK LNG Project.⁶⁹



⁶⁹ FERC, “Alaska LNG Project Final Environmental Impact Statement.” Vol. 3 at 4-924 (March 6, 2020), available at <https://www.ferc.gov/sites/default/files/2020-05/03%2520Alaska%2520LNG%2520FEIS%2520Volume%25203.pdf>.

III. Summary of Defects in the Draft Permit Proposal that Warrant Its Rejection

- Contrary to PSD permitting requirements, neither AGDC nor ADEC included expected emissions associated with the planned 800-mile pipeline that would transport natural gas from the North Slope to Nikiski. By not aggregating the emissions from the pipeline, gas treatment plant and compressor stations with those of the Liquefaction plant, AGDC would be allowed to treat the compressor stations and gas treatment plant as “minor” sources for air permitting purposes—a fact which will allow those facilities to escape the Clean Air Act’s technology-based requirements (i.e., Best Available Control Technology (BACT), limitations on criteria air pollutants) and Maximum Achievable Control Technology (MACT), limitations on hazardous air pollutants) reviews applicable to “major” sources. Permitting the project as one PSD source would mean that the project’s cumulative impacts on air quality including Class I AQRVs would need to be assessed collectively, which would best ensure that the goals of the PSD program are met.
- The BACT analyses for the six compressor turbines and the four power turbines are flawed because the draft permit fails to identify the make and model of each turbine to be installed, which is necessary to know achievable emission rates for several pollutants including greenhouse gases and NO_x⁷⁰
- NO_x BACT for all of the compressor turbines should be based on application of selective catalytic reduction (SCR) because numerous BACT determinations have been made for combustion turbines that require SCR to meet BACT and because SCR will be cost effective. Indeed, ADEC recently proposed a PSD permit which would require SCR as BACT along with Solar turbines’ SoLoNO_x combustors for six power generating combustion turbines at the nearby Agrium U.S., Kenai Nitrogen Operations plant.⁷¹ NO_x limits with SCR would be 78% lower than the limits proposed by ADEC.
- The GHG BACT analysis for the turbines is deficient because the state failed to conduct source-specific analyses for: 1) carbon capture and sequestration; 2) use of electric compressors; and 3) use of the more efficient aeroderivative turbines (which appear to be a particularly good fit for the project and would help SCR work more efficiently). Moreover, Alaska’s GHG BACT limit does not even require that a certain level of combustion efficiency be achieved at the combustion turbines. Alaska

⁷⁰ A policy reason for requiring PSD review, in addition to those discussed in preceding sections, is that subsequent PSD permits to other sources are premised on stability - and accuracy in determining - of the level of emissions from existing sources (in another context, the preamble to the 1980 PSD regulations explained the need for such accuracy and stability “[i]n EPA’s view, any switch to another fuel or raw material that would distort a prior assessment of a source’s air quality impact should have to undergo [PSD] scrutiny.” 45 Fed. Reg. 52,676, 52,704 (1980).

⁷¹ See Preliminary ADEC Technical Analysis Report for Construction Permit AQ0083CPT07 issued to Agrium U.S., Inc., for the Kenai Nitrogen Operations, November 20, 2020, Appendix B: Best Available Control Technology (BACT) at 7-8.

has simply proposed a GHG BACT limit equivalent to EPA's GHG emission factor for all natural gas-burning sources.

- Alaska's BACT analysis for flaring is also deficient, because ADEC failed to consider capture and use requirements (in lieu of flaring the excess natural gas) or the use of a thermal incinerator instead of flaring (which results in better control of volatile organic compounds (VOCs) and NOx. Moreover, ADEC's proposed permit terms for its flaring BACT control of "minimization of flaring" are not adequate to ensure flaring is indeed minimized. ADEC has proposed to limit flaring during equipment startup, shutdown, and maintenance to 500 hours per year per flare, but is not limiting flaring due to plant upsets (likely the major cause of flaring) at all.
- The air quality modeling analyses supporting the Draft PSD Permit relied upon outdated modeling studies completed in 2017 or earlier for the AK LNG Project Final Environmental Impact Statement (FEIS). In addition, the FEIS modeling contained technical errors that tended to underestimate air quality impacts from the proposed Liquefaction plant, and these errors were carried forward to the PSD permit modeling. For example, the modeling failed to properly address maximum short-term impacts from expected flaring episodes at the Liquefaction plant. ADEC attempted to compensate for the known shortcomings in the modeling by performing additional technical analyses, but the ADEC "sensitivity studies" were themselves flawed and incomplete.
- The Class I impact analysis addressing DNPP and TUXE was faulty. In some cases, the AK LNG Project compressor stations would be within 5 km of DNPP, a protected Class I area, yet the Class I PSD increment analysis and air quality related values (AQRV) modeling addressing visibility and acid deposition impacts did not address the AK LNG Project compressor station emissions in combination with the Liquefaction plant and other regional emission sources. Also, the Class I impact modeling failed to address project-related maritime traffic in the Cook Inlet as it passed by TUXE. Despite errors in underestimating various Class I area impacts, the modeling still showed adverse air quality impacts at DNPP and TUXE; however, ADEC has refused to acknowledge such impacts and has not proposed any measures to alleviate the predicted adverse Class I impacts.

IV. The PSD Application is Materially Incomplete

A. ADEC Failed to Properly Define the AK LNG Project as the Source.

The requirements of the PSD program apply to "any new major stationary source,"⁷² and "permitting authority must take into account the emissions from all parts of a single source when

⁷² 40 C.F.R. § 52.21(a)(2); 18 AAC 50.040(h)(3).

determining the applicable requirements and conditions for operation of that source."⁷³ Federal and state regulations define a "stationary source" as "any building, structure, facility or installation that emits or may emit a regulated ... pollutant."⁷⁴ Both sets of regulations further define a "building structure, facility or installation" (and therefore a single "source") according to a three-part test. Under this test, a single source includes "all of the pollutant-emitting activities" that:

- (a) *belong to the same industrial grouping* according to the federal government's Standard Industrial Classification (SIC) system,
- (b) *are located on one or more contiguous or adjacent properties*, and
- (c) *are under the control of the same person* (or persons under common control).⁷⁵

Furthermore, as the D.C. District Court explained:

Section 165 of the Act, 42 U.S.C. § 7475, provides that the owner or operator of a facility seeking a permit must demonstrate "that emissions from *construction or operation* of such facility will not cause, or contribute to, air pollution" 42 U.S.C. § 7475(a)(3) (emphasis added). Thus, the fact that construction is not aimed at completing a unit does not obviate the need for preconstruction review as the EPA [here ADEC] must consider the pollution resulting from the construction itself.⁷⁶

Moreover, "pursuant to the plain language of the statute, and its obvious intent to regulate pollution attendant to the construction as well as the operation of the finished generating units," the permit application must include the emission units that comprise of the facility's structure.⁷⁷ The permitting authority "must prevent any construction not specifically presented and approved during the permit process. This is the only reading of the statute that will effect its manifest purpose."⁷⁸ In other words, if there are numerous emitting units and the permit applicant plans to build the emitting units in a manner that will facilitate all the units "accommodate[ing] the needs of full capacity operation," the overall structure of the facility must be presented in the PSD permit application.⁷⁹ "[I]f the EPA [here ADEC] did not have the opportunity to consider the cumulative impact of the additional construction resulting" from the other unit(s), "then the pollution control aims of the statute have not been protected."⁸⁰

Finally, because determining the relevant source is a "fundamental" aspect of the PSD program, state permitting authorities are required to provide in the record a "reasoned explanation of their source determinations ... consistent with the Act."⁸¹

⁷³ *In the Matter of Seneca Energy, II, LLC*, Order on Petition No. II-2012-01, at (June 29, 2015) (2015 *Seneca Energy Order*) available at https://www.epa.gov/sites/production/files/2016-08/documents/seneca_energy_ii_response_7-29-16_0.pdf.

⁷⁴ AS 46.14.990, 40 C.F.R. § 52.21(b)(5), (6).

⁷⁵ 40 C.F.R. § 52.21(b)(6)(emphasis added), AS 46.14.990.

⁷⁶ *Save the Valley v. Ruckelshaus*, 565 F. Supp. 709, 710 (D.C. Cir. 1983) (*Save the Valley*).

⁷⁷ *Id.*

⁷⁸ *Id.*

⁷⁹ *Id.* at 710-711.

⁸⁰ *Id.* at 711 (further explaining in n.3 that "...if the operator plans to install both lines at the same time, there is little burden in requiring it to present such plan to the EPA.")

⁸¹ 2015 *Seneca Energy Order* at 10.

There is no question that the AK LNG Project is one contiguous stationary source, and that all of the emitting activities that make up operations of the proposed project together comprise a single source of air pollution for purposes of the PSD program.

We start our analysis identifying the pollutant-emitting activities that make up the AK LNG Project: the Gas Treatment Plant (GTP), the compressor stations along the pipeline, the heater stations along the pipeline, the Mainline Pipeline itself, and the LNG facilities. Figure 3 below provides emissions estimates for these various activities that constitute the AK LNG Project, which were identified in the FEIS. FERC’s Order authorizing the AK LNG Project included these same facilities.⁸²

Figure 3. Emission Estimates for the AK LNG Project.

Pollutant-emitting activity	NO _x , tpy	CO, tpy	SO ₂ , tpy	PM ₁₀ /PM _{2.5} , tpy	VOC, tpy	HAPs, tpy	CO ₂ e, tpy
GTP (with Maximum Flare) ⁸³	3,782.1	9,100.1	1,076.3	903.2	13,263.3	108.0	6,607,655
Sagwon Compressor Station with Cooling ⁸⁴	184.6	247.8	4.8	29.1	33.4	10.7	233,785
Five Compressor Stations (Galbraith Lake, Coldfoot, Ray River, Minto, and Healy) ⁸⁵	161 (per station)	244.1 (per station)	4.3 (per station)	13.1 (per station)	21.0 (per station)	8.3 (per station)	206,381 (per station)

⁸² 171 FERC ¶ 61,134 (May 21, 2020) (included as an attachment to these comments)(authorizing AGDC “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).” at 1; and list of the pollutant emitting activities identified in Figure 4 of these comments are list with additional details in ¶¶ 3, 4 at 2-3) (FERC Order).

⁸³ See Table 4.15.5-1 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-937. This includes six natural gas compressor turbines, six CO₂ compressor turbines, 6 power generating turbines, building heaters, generators, pumps, fugitive emissions, and flaring. See also, FERC Order at 2 (“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)”).

⁸⁴ See Table 4.15.5-11 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-947. This includes three compressor turbines, four natural gas powered generators, two auxiliary utility glycol heaters, one waste incinerator, and fugitive emissions and blowdowns. See also, FERC Order at 2 (“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)”).

⁸⁵ See Table 4.15.5-12 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-948. Each of these compressor stations would include one compressor turbine, three power generators, two auxiliary utility glycol heaters, one waste incinerator, and fugitive emissions and blowdowns. See also FERC Order at 3 (“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)”).

Honolulu Creek Compressor Station ⁸⁶	131.6	200.5	3.5	10.6	13.7	6.6	166,013
Rabideux Creek Compressor Station ⁸⁷	144.8	220.7	4.0	12.1	14.7	6.8	191,658
Theodore River Heater Station ⁸⁸	49.3	103.4	2.6	8.7	16.3	4.2	125,201
Mainline Pipeline ⁸⁹							272 ⁹⁰
Liquefaction Facilities Operation & Marine Terminal (with Maximum Flaring) ⁹¹	4,257.3	14,136.9	184.5	1,324.6	21,480.8	145.2	7,901,876
Total Emissions of Project	9,354.7	25,229.9	1,297.2	2,353.8	34,927.2	323.0	16,258,365

Emissions from the Mainline Pipeline are incomplete and inaccurate. FERC estimated the GHG emissions from the Mainline Pipeline to be 272 tons of CO₂ equivalent (CO₂e) emissions per year.⁹² The listed reference for this estimate was the Interstate Natural Gas Association of America database, 2005.⁹³ According to information on the emission factors of

⁸⁶ See Table 4.15.5-13 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-949. This compressor station would include one compressor turbine, three power generators, two auxiliary utility glycol heaters, one waste incinerator, and fugitive emissions and blowdowns. *See also* FERC Order at 3 (“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)”).

⁸⁷ *Id.* This compressor station would include one compressor turbine, three power generators, two auxiliary utility glycol heaters, one waste incinerator, five indirect gas-fired heaters, and fugitive emissions and blowdowns. *See also* FERC Order at 3 (“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)”).

⁸⁸ See Table 4.15.5-14 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-950. This includes two natural gas-fired power generators, nine indirect-fired natural gas heaters, one waste incinerator, fugitive emissions and blowdowns. *See also* FERC Order at 3 (“a stand-alone gas heater station, located at Mainline MP 749.1 in the Matanuska-Susitna Borough (Theodore River Heater Station)”).

⁸⁹ See Table 4.15.5-15 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-950. These emissions would be mostly methane, and the pollutants would be emitted from “piping components and connectors along the Mainline Pipeline.” Moreover, although AGDC did not quantify VOC emissions that would be released from the pipeline, there would undoubtedly be VOC emissions as well as CO₂e (i.e., methane) emissions. *See* Table EC-3, Liquefaction Facility Fuel Specifications, of October 16, 2011 Emissions Calculations Report for the Liquefaction Facility, Appendix A at 57 (at pdf page 371 of the file entitled “AQ1539CPT01 Application Attachments 4 and 5”). *See also* FERC Order at 3 (“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)”).

⁹⁰ We disagree with this estimate. See discussion following this table.

⁹¹ See Table 4.15.5-20 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-961. This includes six natural gas-fired compressor turbines, four natural gas-fired combined cycle power turbines, flaring, thermal oxidizer, LNG carriers and tugs, and other associated equipment. *See also* FERC Order at 3 (“liquefaction facilities capable of producing up to 20 MMTA 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)”).

⁹² See Table 4.15.5-15 of Volume 3 of the March 2020 Final EIS for the Alaska LNG Project, at page 4-950.

⁹³ *Id.* Appendix Z of the FEIS lists the references for the EIS, the cited reference for “Interstate Natural Gas Association of America (2005), Table 4-3” was listed as the Interstate Natural Gas Association of America database available online at <https://www.ingaa.org/>.

this reference, it appears that the emission factors used only accounted for fugitive emissions from the pipeline itself and emissions from meters of which only two are planned for the Mainline Pipeline (one at the beginning and one at the end of the 806.6 mile pipeline).⁹⁴ However, can also occur due to blowdowns. A blowdown is a release of gas from a pipeline so that testing, maintenance, or repairs can be done on a section of pipeline. The Mainline Pipeline will have thirty mainline valves at which it can isolate a section of the pipeline that needs to be maintained or repaired.⁹⁵ Those valves are spaced as long as 46.6 miles apart to as close as 6.5 miles,⁹⁶ and the average distance between valves is 27.8 miles apart. If we assume that all of the gas in an average length of the pipeline is vented in a blowdown for maintenance, that would equate to as much as 5.6 million cubic feet of gas purged.⁹⁷ AGDC states that 91.15% of the volume of natural gas would be methane,⁹⁸ thus the 5.6 million cubic feet of gas purged would equate to 5.15 million cubic feet of methane or 131,549 tons of methane from one blowdown on an average length of pipeline between mainline valves.⁹⁹ The CO₂e emissions from one blowdown event would be potentially as high as 3.28 million tons.¹⁰⁰

As another source of fugitive emission estimates from natural gas pipelines, the Intergovernmental Panel on Climate Change (IPCC) has provided a methane emission factor of 0.0037 gigagrams per kilometer of U.S. natural gas transmission pipeline.¹⁰¹ For the Mainline Pipeline, that would equate to 5,251 tons of methane emitted per year,¹⁰² which equates to 131,278 tons per year of CO₂e emissions.¹⁰³ It is not clear whether the IPCC emission factor accounts for blowdowns.¹⁰⁴ Both of these CO₂e estimates are clearly much higher than FERC's estimate of 272 tons per year.

⁹⁴ See Section 9.2.5.2.1.4 of Resource Report 9 of the April 2017 Alaska LNG Project Application to the Federal Energy Regulatory Commission, available at <https://alaska-lng.com/regulatory-process/ferc-application-exhibits/resource-reports/>.

⁹⁵ FEIS for Alaska LNG Project, Volume 3, at 4-1147 (Table 4.18.10-5).

⁹⁶ *Id.*

⁹⁷ Based on the stated Mainline Pipeline diameter of 42 inches, see FEIS for Alaska LNG Project at ES-1.

⁹⁸ See March 2018 Permit Application for Alaska LNG Project, Table EC-3, Liquefaction Facility Fuel Specifications, of October 16, 2011 Emissions Calculations Report for the Liquefaction Facility, Appendix A at 57 (at pdf page 371 of the file entitled "AQ1539CPT01 Application Attachments 4 and 5").

⁹⁹ Cubic feet of methane was converted to mass of methane based on the density of methane of 0.656 kilograms per cubic meter (51.07 lb/cubic foot), from July 2015, U.S. Department of Energy, Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain – Sankey Diagram Methodology, at 15 (Appendix 2, Table 3), available at [QER Analysis - Fuel Use and GHG Emissions from the Natural Gas System, Sankey Diagram Methodology 0.pdf \(energy.gov\)](https://www.energy.gov/energy-efficiency/energy-analysis-fuel-use-and-ghg-emissions-from-the-natural-gas-system-sankey-diagram-methodology-0.pdf).

¹⁰⁰ The CO₂ equivalent emissions are calculated by multiplying the methane emissions by its global warming factor of 25. See 40 C.F.R. § 52.21(b)(49)(ii)(c) and 40 C.F.R. § 98, Table A-1.

¹⁰¹ Intergovernmental Panel on Climate Change, "Fugitive Emissions from Oil and Natural Gas Activities," in *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, 103–127, 113 (2001), available at https://www.ipcc-nggip.iges.or.jp/public/gp/bgp/2_6_Fugitive_Emissions_from_Oil_and_Natural_Gas.pdf.

¹⁰² Assuming an 800 mile length (or 1,287.5 kilometers) of the Mainline Pipeline, and using a conversion factor of 1,102.31 tons per gigagram.

¹⁰³ The CO₂ equivalent emissions are calculated by multiplying the methane emissions by its global warming factor of 25. See 40 C.F.R. § 52.21(b)(49)(ii)(c) and 40 C.F.R. § 98, Table A-1.

¹⁰⁴ See Intergovernmental Panel on Climate Change, "Fugitive Emissions from Oil and Natural Gas Activities," in *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, at 118 (2001)

Regardless of the scope of CO_{2e} emissions from the Mainline Pipeline, there is no question that the Mainline Pipeline is an emitting activity. In fact, not only will methane be emitted from the Mainline Pipeline, but also volatile organic compounds (VOCs) will be emitted from the pipeline. AGDC's permit application indicates that the LNG fuel gas will be approximately 2.3% by volume composed of VOCs such as Propane, IsoButane, Normal Butane, IsoPentane, N-Pentane, and other VOCs.¹⁰⁵ Thus, although FERC did not provide an estimate of VOC emissions for the Mainline Pipeline, fugitive emission releases from the pipeline will include VOC emissions because the gas stream will not be pure methane. With respect to blowdown emissions, the emissions of just one VOC, propane, which AGDC indicates would constitute 1.89% of the natural gas stream,¹⁰⁶ would potentially be as high as 8,346 tons from one blowdown of an average length of pipeline between valves.¹⁰⁷

Permitting status of the emitting units. Before applying the single source test, it is important to explain the permitting status of the emitting units in Figure 3. According to ADEC's online database of issued permits, ADEC permitted the AGDC gas treatment plant (GTP) in a PSD permit (Construction Permit: AQ1524CPT01) on August 13, 2020.¹⁰⁸ In the Public Notice for the proposed Liquefaction plant, ADEC "has made a preliminary decision to approve Alaska Gasline Development Corporation's (AGDC's) application for Air Quality Control Construction Permit AQ1539CPT01 for the Liquefaction plant."¹⁰⁹ Thus, ADEC proposes to issue a separate PSD permit for the LNG Plant. Neither the pipeline compressor stations or heater station – that are part of the AK LNG Project - have, to our knowledge, been permitted by ADEC.¹¹⁰

The first part of the single source test is whether the pollutant-emitting activities are considered as part of the same industrial grouping. The pollutant-emitting activities are considered part of the same industrial grouping if they belong to the same *Major Group* (i.e., which have the same two-digit code) as described in the *Standard Industrial Classification Manual, 1972*, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).¹¹¹

¹⁰⁵ See March 2018 Permit Application for Alaska LNG Project, Table EC-3, Liquefaction Facility Fuel Specifications, of October 16, 2011 Emissions Calculations Report for the Liquefaction Facility, Appendix A at 57 (at pdf page 371 of the file entitled "AQ1539CPT01 Application Attachments 4 and 5").

¹⁰⁶ See March 2018 Permit Application for Alaska LNG Project, Table EC-3, Liquefaction Facility Fuel Specifications, of October 16, 2011 Emissions Calculations Report for the Liquefaction Facility, Appendix A at 57.

¹⁰⁷ Cubic feet of propane was converted to mass of propane based on the density of propane of 2.010 kilograms per cubic meter (156.5 lb/cubic feet), from July 2015, U.S. Department of Energy, Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain – Sankey Diagram Methodology, at 15 (Appendix 2, Table 3).

¹⁰⁸ See Alaska Department of Environmental Conservation Air Permits Program, "Technical Analysis Report For the terms and conditions of Construction Permit AQ1524CPT01 Issued to Alaska Gasline Development Corporation For the Gas Treatment Plant," (Aug. 13, 2020); Department of Environmental Conservation, "Air Quality Control Construction Permit: AQ1524CPT01," Alaska Gasline Development Corporation, Permittee (Aug. 13, 2020).

¹⁰⁹ Public Notice, State of Alaska, Department of Environmental Conservation, Alaska Gasline Development Corporation, Liquefaction Plant.

¹¹⁰ There are no other permitted or proposed permits listed in ADEC's online database for the AGDC, nor does AGDC have any permit applications listed in ADEC's online "Queue" database listing. See Screenshot of ADEC Issued Air Permits; Screenshot of ADEC Permit Applications (included as attachments to these comments).

¹¹¹ AS 46.14.990, 40 C.F.R. § 52.21(b)(6).

The AGDC LNG Plant and the pipeline compressor stations all belong to the same industrial grouping – Major Group 49.¹¹² Specifically, the main pipeline and pipeline compressor stations fall under the industrial code of natural gas transmission (SIC 4922) and the LNG Plant falls under the standard industrial code of 4924 (Natural Gas Distribution).¹¹³ In addition, ADEC has identified the Gas Treatment Plant as classified under Standard Industrial Classification Code 4922, so the GTP is also of the same Major Group 49.¹¹⁴ Therefore, the AK LNG Project meet the first part of the test.

The second part of the single source test is whether the emitting units are on one or more contiguous or adjacent properties. First, the permit application for the Alaska LNG permit made available to the public by ADEC includes Resource Report No. 1 (April 14, 2017), which describes the emitting units that are part of the AK LNG Project, which are all connected to one another by the Mainline Pipeline which also is an emitting activity:

[A] liquefaction facility (Liquefaction Facility) in Southcentral Alaska; an approximately 807-mile gas pipeline (Mainline); a gas treatment plant (GTP) within the PBU on the North Slope; an approximately 63-mile gas transmission line connecting the GTP to the PTU gas production facility (PTU Gas Transmission Line or PTTL); and an approximately 1-mile gas transmission line connecting the GTP to the PBU gas production facility (PBU Gas Transmission Line or PBTL).”¹¹⁵

The report further explains how the various units will facilitate operation of the AK LNG Project

The Alaska Gasline Development Corporation (Applicant) plans to construct one integrated liquefied natural gas (LNG) Project (Project) with *interdependent facilities* for the purpose of liquefying supplies of natural gas from Alaska, in particular from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas.¹¹⁶

¹¹² Major Group 49 - Electric, Gas, and Sanitary Services. Major Group 49 also includes within it “Industry Group 494: Gas Production and Distribution.” which are “[e]stablishments engaged in the transmission and/or storage of natural gas for sale”—most notably, “pipelines [for] natural gas”—as well as any establishments that combine aspects of electric generation and natural gas transmission. Though the Department of Labor has largely phased-out the Standard Industrial Classification (SIC) Manual in favor of the newer North American Industry Classification System, it maintains an online, hypertext edition of the Manual. *See* Department of Labor, SIC Division Structure, <https://www.osha.gov/data/sic-manual>.

¹¹³ *See* NAICS Association, Standard Industrial Code Divisions, Major Group 49 – Electric, Gas, and Sanitary Service, available at <https://www.naics.com/standard-industrial-code-divisions/?code=49>. *See also* Alaska LNG Permit Application, Project Information Form at 1.

¹¹⁴ *See* ADEC’s Final Technical Analysis Report for the Alaska Gasline Development Corporation Gas Treatment Plant, Construction Permit AQ1524CPT01, August 13, 2020, at 2 (Section 1.2).

¹¹⁵ Alaska LNG Permit Application, Resource Report No. 1 (April 14, 2017), at 1-1.

¹¹⁶ Alaska LNG Permit Application, Resource Report No. 1 (April 14, 2017), at 1-1(emphasis added). This Resource Report is in the application file that was posted to ADEC’s public notice website in October 2020 with the filename “AQ1539CPT01 Application Attachments 1 through 3.PDF” beginning at pdf page 82.

This report further explains that in order for the AK LNG Project to operate “*All of these facilities are essential* to export natural gas in foreign commerce and will have a nominal design life of 30 years.”¹¹⁷

ADEC posted this report as part of the PSD permit application for the LNG plant stating that the LNG Terminal would include the following “interdependent facilities” among other facilities:

Mainline Facilities: A new 42-inch-diameter natural gas pipeline approximately 807 miles in length would extend from the Liquefaction Facility to the GTP in the PBU,¹¹⁸ including the structures, equipment, and all other associated systems. The proposed design anticipates up to eight compressor stations;¹¹⁹ one standalone heater station, one heater station collocated with a compressor station, six cooling stations associated with six of the compressor stations;¹²⁰ four meter stations; 30 Mainline block valves (MLBVs)¹²¹ one pig launcher facility at the GTP meter station, one pig receiver facility at the Nikiski meter station, and combined pig launcher and receiver facilities at each of the compressor stations;¹²² and associated infrastructure facilities.¹²³

GTP: A new GTP and associated facilities in the PBU would receive natural gas from the PBU Gas Transmission Line and the PTU Gas Transmission Line. The GTP would treat/process the natural gas for delivery into the Mainline Pipeline. There would be custody transfer, verification, and process metering between the GTP and PBU for fuel gas, propane makeup, and byproducts. All of these would be on the GTP or PBU pads
...¹²⁴

¹¹⁷ *Id.* (emphasis added).

¹¹⁸ The Mainline Pipeline would be buried with the exception of two aerial waterbody crossings, four aboveground crossings of active faults, and the 27.3-mile-long offshore portion in Cook Inlet, which would be laid on the seabed. *See* Final EIS, Vol. 1 at 2-13.

¹¹⁹ Each compressor station includes one or more compressor turbines, 2-4 power generators, 1-2 glycol heaters, and a waste incinerator. *See* Final EIS, Vol. 1 at 2-16.

¹²⁰ “Natural gas engine-driven power generators would generate electric power for the compressor stations.” Final EIS, Vol. 1 at 2-15.

¹²¹ “Operating the Mainline Pipeline would require the installation of 30 MLVs ... MLVs would be at the GTP, at each of the eight compressor stations and the heater station, and at the LNG Plant. The remaining 18 MLVs would be stand-alone facilities installed within the Mainline Pipeline right-of-way. ... Each MLV site would include a blowdown valve, a pipeline break control system, and an adjacent helipad.” Final EIS, Vol. 1 at 2-17.

¹²² “Launchers and receivers are facilities where internal pipeline cleaning and inspection tools, known as “pigs,” are inserted or retrieved from the pipeline. Launchers/receivers generally consist of a 20- to 30-foot segment of aboveground piping that tie into the pipeline below the ground surface. A launcher would be installed at the GTP Meter Station; combined sets of launchers/receivers would be installed at each compressor and heater station; and a receiver would be installed at the Nikiski Meter Station.” Final EIS, Vol. 1 at 2-18.

¹²³ Additional facilities include, for example: (1) Cathodic protection systems that help prevent corrosion of underground pipeline facilities. These systems typically include an aboveground transformer-rectifier unit and an associated anode ground bed underground. Select compressor stations, meter stations, and MLV sites would have cathodic protection system facilities (e.g., ground beds and rectifiers). Final EIS, Vol. 1 at 2-18. (2) Mainline MOF, which would consist of a pier and roll-on/roll-off ramp on the west side of Cook Inlet to support onshore and offshore pipeline construction, including AGDC placing fuel tanks on the dock to refuel barges. An average of 67 marine vessels per year would arrive at the Mainline MOF, with the peak year occurring in Year 2. Final EIS, Vol. 1 at 2-17 – 2-19.

¹²⁴ Alaska LNG Permit Application, Resource Report No. 1 (April 14, 2017), at 1-2.

Natural Gas-Fired Heater Station: is also proposed to be located between the last compressor station (which will also have heaters) and the LNG Plant.¹²⁵ The FEIS for the project indicates that heaters will be used when ambient temperatures drop below freezing.¹²⁶

Additional information demonstrates the contiguousness and interrelatedness of the AK LNG Project. For example, Figure 1.1-2 of Resource Report No. 1 is a schematic of the “Project Facilities Overview” that includes all of the air pollution sources mentioned (e.g., GTP facility, compressor stations, heater station, and the Liquefaction plant).¹²⁷ Furthermore, ADEC stated in its Technical Analysis Report for the GTP that it “is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaska’s North Slope to international markets in the form of LNG.”¹²⁸ The FEIS describes the primary function of the GTP as follows:

The feed gas produced from the [Point Thompson Unit (PTU)] and [Prudhoe Bay Unit (PBU)] contains carbon dioxide (CO₂), hydrogen sulfide (H₂S), water and other impurities that require removal prior to liquefaction. The GTP would remove these byproducts from the natural gas, then chill, compress, and send out processed natural gas into the Mainline Pipeline.

FEIS at 2-2 (Section 2.1.3.1) (emphasis added).¹²⁹

The Mainline Pipeline and associated facilities has the primary purpose of transmitting the treated gas to the Liquefaction plant. According to the FEIS for the AK LNG Project, the eight compressor stations currently planned, “would use natural gas-fired engines to maintain pressure within the Mainline Pipeline to deliver the contracted volumes of natural gas to the Liquefaction Facilities.”¹³⁰ Furthermore, FERC’s order also describes the connected nature of the AK LNG Project, explains that it 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

¹²⁵ See March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 1 at 2-15.

¹²⁶ *Id.* at 2-58.

¹²⁷ Alaska LNG Permit Application, Resource Report No. 1 (April 14, 2017), at 1-3.

¹²⁸ See ADEC’s Final Technical Analysis Report for the Alaska Gasline Development Corporation Gas Treatment Plant, Construction Permit AQ1524CPT01, August 13, 2020, at 2 (Section 1.3).

¹²⁹ See March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 1 at 2-2, available at <https://www.ferc.gov/industries-data/natural-gas/final-environmental-impact-statement-0>.

¹³⁰ *Id.* at 2-14. See also FERC, “An Interstate Natural Gas Facility on My Land?: What Do I Need to Know?” at 28 (2015), available at <https://www.ferc.gov/sites/default/files/2020-04/AnInterstateNaturalGasFacility.WhatYouNeedToKnow.pdf> (natural gas pipeline projects need “[c]ompressor stations” to be “strategically placed along the pipeline to boost the system pressure to maintain required flow rates.”)

Kenai Peninsula designed to produce up to 20 million metric tons per annum (MMTPA) of LNG (Liquefaction Facilities) for export.¹³¹

Although the precise number of gas interconnections are unclear, AGDC plans contemplate interconnections for in-state deliveries of natural gas, and ADEC should evaluate those projects consistent with the single source analysis presented in these comments. As currently planned, the FEIS indicated that the Mainline Pipeline will have, at a minimum, three gas interconnections “to allow for future in-state deliveries of natural gas” to serve the Fairbanks area, the Anchorage/Matanuska-Susitna Valley area, and the Kenai Peninsula area.¹³² While FERC’s final order explains that “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,”¹³³ the extent of any such interconnections to take some of the natural gas destined for the LNG plant is currently unknown.¹³⁴ Additional facilities would need to be constructed to move the natural gas from the interconnection points to the in-state customers. Indeed, the FEIS indicates that “[t]here are currently no plans to construct additional facilities, such as off-take stations, lateral pipelines, or distribution systems, to provide future natural gas deliveries to in-state customers.”¹³⁵ Thus, as currently proposed, the GTP and pipeline compressor stations would be solely for the purpose of transporting the treated natural gas to the LNG plant. Even if at some point in the future there are in-state customers serviced by the gas that is processed through the GTP and the Mainline Pipeline compressor stations, the GTP and Mainline Pipeline compressor stations would still be integral to the ability of the LNG plant to create the liquefied natural gas product. Moreover, that the Project may at some point deliver gas to locations other than the Liquefaction plant in inapposite. Structures that will be used in common by more than one unit must be presented in the permit application nonetheless.¹³⁶

The third part of the test is whether the pollutant-emitting activities are under control of the same person. Alaska’s SIP defines “person” broadly as any “individual, corporation, partnership, association, a governmental body, a municipal corporation, or any other legal entity.”¹³⁷ The GTP, the main pipeline, the compressor stations, and the LNG Plant will be under the control of the same person – i.e., the Alaska Gasline Development Corporation. On April 26, 2018, the AGDC submitted the initial PSD Application for the LNG Plant to ADEC - although it was found by ADEC to be incomplete and based on the missing information identified in these comments, is still incomplete – the PSD permit application was submitted by

¹³¹ FERC Order at 2.

¹³² FEIS Volume 1 at 2-20.

¹³³ FERC Order at 2.

¹³⁴ See March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 3 at 4-1165, available at <https://www.ferc.gov/industries-data/natural-gas/final-environmental-impact-statement-0>.

¹³⁵ *Id.*

¹³⁶ *Save the Valley* at 711.

¹³⁷ AS 46.14.990(21)(“person” has the meaning given in AS 01.10.060 and also includes an agency of the United States, a municipality, the University of Alaska, the Alaska Railroad Corporation, and other departments, agencies, instrumentalities, units, and corporate authorities of the state;”); AS 01.10.060(a)(8)(“person” includes a corporation, company, partnership, firm, association, organization, business trust, or society, as well as a natural person.)

AGDC.¹³⁸ The construction permit ADEC issued for the GTP was also issued to the AGDC.¹³⁹ On April 17, 2017, AGDC filed an application under section 3 of the Natural Gas Act (NGA) and Part 153 of the FERC's regulations 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 (AK LNG Project).¹⁴⁰ FERC's order granted authorization to AGDC for the proposed AK LNG Project, which as described in the footnotes to Figure 3, contain the same emitting units covered by CAA requirements. Moreover, while FERC's order described AGDC as a "public corporation," the definition of person includes "corporate authorities of the state."¹⁴¹

Thus, the GTP, the Mainline Pipeline compressor stations, the heater station, and the LNG plant should all be considered as one major stationary source under the PSD permitting program. All of these sources have common ownership and control, in that the AGDC is the current owner and planned operator of all of these facilities. In addition, all of the facilities are classified under the same major Standard Industrial Classification code of 49 – Electric, Gas and Sanitary Services. And, all the emitting units are connected to each other by the Mainline Pipeline and contiguous and adjacent to one another.

Importantly, the underground pipeline is itself a "pollutant-emitting activity" producing methane and volatile organic compound emissions from component leaks¹⁴² and periodic blowdown¹⁴³ activities.¹⁴⁴ Metering and regulating stations, valves, and the pipeline itself also

¹³⁸ ADEC Air Quality Construction Permit Application, Permit Information Form, Section 2, at 1.

¹³⁹ Air Quality Control Construction Permit: AQ1524CPT01 at 1.

¹⁴⁰ FERC Order at 1.

¹⁴¹ FERC Order at 1 ("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.").

¹⁴² Although so-called "fugitive emissions" from component leaks are not always included in determining whether the potential to emit of a stationary source exceeds the major stationary source emission thresholds under the PSD program, Alaska's SIP unequivocally considers such fugitive emissions to be "emissions of a stationary source." See 18 AAC 50.990(52) and 40 C.F.R. §51.166(b)(1) (definition of "major stationary source"). Accordingly, fugitive emissions from otherwise major sources are included in "all subsequent analyses, including PSD applicability for other individual pollutants (i.e., comparing emissions to the significant emission rates), BACT analyses, and air quality impact analyses." Environmental Protection Agency, *Counting GHG Fugitive Emissions in Permitting Applicability*, 2 (July 2015), available at <https://www.epa.gov/sites/production/files/2015-07/documents/ghgfeqa.pdf>.

¹⁴³ "Blow" or "blowdown" activities involve the venting of natural gas contained inside a pipeline into the atmosphere. See Environmental Protection Agency, *Methane Emissions from the Natural Gas Industry*, Vol. VII: *Blow and Purge Activities*, 2 (1996), available at https://www.epa.gov/sites/production/files/2016-08/documents/7_blowandpurge.pdf, which are planned here. See also, FERC Order at 79 ("Blowdowns would occur at compressor stations and mainline valves as part of normal pipeline safety operations.").

¹⁴⁴ See also Environmental Protection Agency, *Oil and Natural Gas Sector Leaks*, 3, 21–22 (2014); *Oil and Natural Gas Sector: Emission Standards for New and Modified Sources*, 80 Fed. Reg. 56593, 56607 (proposed Sept. 18, 2015) ("In addition to vented emissions, methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the [natural gas] infrastructure, from connections between pipes and vessels, to valves and equipment"); *id.* at 56642 (even a natural gas transmission "facility with proper operation would likely find one to three percent of components to have fugitive emissions"); Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (1990-2018), 3-84, available at <https://www.epa.gov/sites/production/files/2020-04/documents/us-ghg-inventory-2020-main-text.pdf> ("Emissions

have the potential to emit volatile organic compounds and greenhouse gases. As such, the above- and below-ground facilities associated with the pipeline component of the proposed source must be identified in the PSD permit application.¹⁴⁵

Furthermore, although the highly unique facts of the AK LNG Project demonstrate that all the emitting units identified in Figure 4 must be permitted as a single source under the PSD program, EPA's historical analysis of the functional relationship or the functional interrelatedness between facilities to determine whether they should be considered "contiguous and adjacent" and thus one stationary source, also supports aggregating the AK LNG Project components.

For example, in a 1996 determination, the EPA found that the Anheuser-Busch brewery and the Nutri-Turf landfarm that were about six miles apart were nonetheless considered to be a single stationary source.¹⁴⁶ In this case, the facilities were under common ownership and the brewery wastewater stream was piped to the landfarm where it was disposed. EPA found that the volatile organic compound emissions at the landfarm were a "direct result of brewery operations."¹⁴⁷ EPA relied heavily on the fact that the landfarm was a "support facility" to the brewery to make this determination even though the landfarm had a different two digit major SIC code than the brewery.¹⁴⁸ EPA defined "support facilities" as "those that convey, store, or otherwise assist in the production of the principal produce or group of products produced or distributed...."¹⁴⁹ With respect to whether the facilities were considered "contiguous or adjacent," EPA stated that it considered the two facilities to meet this criteria because "the landfarm operation is an integral part of the brewery operations" and stated that "[t]he additional fact that a *pipeline physically connects the brewery and landfarm* strengthens the conclusion that the brewery operation is dependent on the landfarm operations."¹⁵⁰ EPA relied on the functional

from normal operations [natural gas systems] include: natural gas engine and turbine uncombusted exhaust, flaring, and leak emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions.) 3-84. Environmental Protection Agency National Risk Management Research Laboratory, *Methane Emissions from the Natural Gas Industry, Vol. IX: Underground Pipelines*, 55-57 (1996), available at <https://nepis.epa.gov/Exe/ZyNET.exe/P100UMFU.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1995+Thu+1999&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C95thru99%5CTxt%5C00000039%5CP100UMFU.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL>; See also Environmental Protection Agency Region VI, PSD Permit Statement of Basis for Apex Matagorda Energy, Permit No. PSD-TX-107055-GHG, 6 (Jan. 2013), available at <https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/apex-matagorda-sob013114.pdf> (including within source and applying BACT to natural gas pipeline and metering station supplying power plant).

¹⁴⁵ 18 AAC 50.040(h)(12), 40 C.F.R. § 52.21(n).

¹⁴⁶ See EPA Memorandum with Subject: "Analysis of the Applicability of Prevention of Significant Deterioration (PSD) to the Anheuser-Busch, Incorporated Brewery and Nutri-Turf, Incorporated Landfarm at Fort Collins, Colorado," available at <https://www.epa.gov/nsr/analysis-applicability-psd-anheuser-busch-incorporated-brewery-and-nutri-turf-incorporated> (Aug. 27, 1996).

¹⁴⁷ *Id.* at 2.

¹⁴⁸ *Id.* at 3.

¹⁴⁹ *Id.*

¹⁵⁰ *Id.* at 4 (emphasis added).

interrelatedness of the two facilities in determining that such facilities should be considered “contiguous or adjacent.”

There have been other examples of EPA single source determinations involving facilities that were located some distance apart, including the following:

- 1) *American Soda Commercial Mine and Processing Plant in Colorado*. This mine and processing plant were to be 35-40 miles apart, connected by a 44-mile pipeline. EPA found that the two facilities “clearly will be functionally interdependent, as evidenced by the dedicated slurry pipeline and the spent brine return pipeline which will connect the two facilities.”¹⁵¹ EPA also stated that “[a]dditional evidence is that one facility (the mine) is to produce an intermediate product for processing at the other facility (the processing plant)” and that due to “the integral connectedness of these facilities,” the distance between the facilities should not preclude the facilities from being considered adjacent.¹⁵²
- 2) *Great Salt Lake Minerals plant and a pump station in Utah*. This was a minerals plant located on one side of the Great Salt Lake and a pumping station on the other side of the Great Salt Lake, 21.5 miles apart. EPA found that the pumping station, which transported raw materials to a processing plant, was a support operation to the minerals plant.¹⁵³
- 3) *District Energy St. Paul Combined Heat and Power Plant and Environmental Wood Supply in Minnesota*. The District Energy St. Paul power plant was a biomass-fueled power plant, and it obtained its biomass from Environmental Wood Supply, which was located 3 miles from the power plant.¹⁵⁴ EPA states that “[e]ach day, seven days per week, [Environmental Wood Supply] transports by public roadway up to 40 truck-loads of fuel-grade product” for use in the biomass-fueled power plant.¹⁵⁵ EPA found that despite these two plants not having the same major group standard industrial classification code, Environmental Wood Supply and District Energy St. Paul had a “support or dependency relationship” because Environmental Wood Supply provided the necessary fuel to the power plant which it needed to produce electricity.¹⁵⁶ EPA also found that the two facilities had common ownership and thus were under common control.¹⁵⁷

¹⁵¹ See EPA Letter from Richard R. Long, Air and Radiation Program, EPA Region VIII, to Mr. Dennis Myers, Air Pollution Control Division, Colorado Department of Public Health and Environment, at 1, available at <https://www.epa.gov/nsr/american-soda-multi-facility-source-determination> (April 20, 1999).

¹⁵² *Id.*

¹⁵³ See EPA letter from Richard R. Long, Air Program, EPA Region VIII, to Lynn R. Menlove, New Source Review Section, Utah Department of Environmental Quality, at 1-2, available at <https://www.epa.gov/nsr/great-salt-lake-minerals-source-determination> (Aug. 8, 1997).

¹⁵⁴ See EPA letter from Pamela Blakely, Air Permits Section, EPA Region V, to Don Smith, Air Quality Permits Section, Minnesota Pollution Control Agency, at 1, available at <https://www.epa.gov/nsr/single-source-applicability-determination-environmental-wood-supply-llc-and-district-energy-st> (March 23, 2010).

¹⁵⁵ *Id.* at 2.

¹⁵⁶ *Id.*

¹⁵⁷ *Id.* at 4.

There are key similarities between these EPA single-source determinations and the AGDC's proposed liquefied natural gas project. For example, as discussed above, there are other EPA single source determinations involving facilities that were some distance apart. First, EPA found the two facilities American Soda Commercial Mine and Processing Plant in Colorado, which were 35-40 miles apart and connected by a 44-mile pipeline, were functionally interdependent. Due to their integral connectedness, and the distance between them did not preclude the facilities from being considered adjacent. These points also apply to the GTP, compressor stations, and the LNG plant. The GTP will produce the intermediate product (i.e., natural gas that meets necessary limitations for the Liquefaction plant) that will then be transported via pipeline to the liquified natural gas plant, where it will undergo liquification and distribution. In addition, the GTP, compressor stations and the LNG plant are interconnected. The LNG plant would not be able to exist if it weren't for the GTP and the compressor stations moving the gas through the pipeline to the LNG plant. And the GTP and the pipeline compressor stations would not exist without the LNG plant to liquefy the gas such that it can be sold and transported.

Second, the minerals plant and pump station at the Great Salt Lake Minerals facility in Utah were on opposite sides of the Great Salt Lake, 21.5 miles apart, and EPA found that the pumping station, which transported raw materials to a processing plant, was a support operation to the minerals plant. Similarly, the AGDC compressor stations will transport the natural gas to the Liquefaction plant, and in one location also crossing the water. Thus, the compressor stations are support operations necessary to the Liquefaction plant.

Furthermore, the AK LNG Project will consist of facilities that are, on average, approximately 90 miles apart from each other (i.e., GTP to 1st compressor station, or compressor station to compressor station, or heater station to LNG plant). While it is not clear whether EPA has previously found that a collection of facilities like this should be considered one source under the PSD permitting program, the fact is that the AK LNG Project is a unique source. One of the circumstances that makes the AK LNG Project unique is that the sources of natural gas are in northern Alaska, but the best shipping routes for transport of the liquefied natural gas to international clients are 800 miles to the South in the Cook Inlet. Because of concerns with such a long pipeline going through the Alaskan wilderness with most of the length of the pipeline traveling over permafrost,¹⁵⁸ it is necessary to have the GTP both remove acid gases that could be corrosive to the pipeline (potentially resulting in pipeline leaks that could be damaging to wildlife and the environment) and to chill the natural gas (so as not to negatively affect the permafrost).¹⁵⁹

The relationship between the gas treatment facility and Liquefaction plant is established. As stated in the FEIS, the Liquefaction plant is necessary to remove several impurities from the natural gas that must be removed prior to liquefaction.¹⁶⁰ There are several examples of LNG plants where the gas treatment facilities and the liquefaction plants are collocated. At the proposed Jordan Cove Energy Project LNG terminal to be located in Coos Bay, Oregon, there

¹⁵⁸ See March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 1, at 4-70.

¹⁵⁹ *Id.* at 2-7, 4-105.

¹⁶⁰ *Id.* at 2-2.

are plans for gas treatment facilities (including acid gas removal) at the same location as the liquefaction facilities.¹⁶¹ The Golden Pass LNG Plant under construction in Texas also is proposed to have gas treatment facilities including acid gas removal systems collocated with the liquefaction facilities.¹⁶² Additionally, existing LNG operations collocate the gas treatment and liquefaction activities.¹⁶³ The fact that the AGDC gas treatment facilities are located approximately 800 miles from AGDC's proposed Liquefaction appears to be a function of the fact that the AK LNG Project is planned within the state of Alaska, with its unique characteristics that necessitate the project being constructed in the manner in which it was proposed. However, those facts do not discount the requirement that the GTP, the Mainline Pipeline, the compressor stations and heater station, and the Liquefaction plant are parts of a single project and therefore must be considered as a single major stationary source under the PSD permitting program. In this case, while the facilities are all inherently related to AGDC's ability to operate a liquefaction plant, the facilities must be separated in distance. That unique fact should not result in a finding that commonly-owned facilities of the same major two-digit Standard Industrial Classification Code proposed for the same purpose (i.e., to operate an LNG plant) are not a single stationary source, because that would be inconsistent with the PSD permitting regulations.

Moreover, Alaska did not adopt in its SIP regulations the optional regulatory provisions offered in EPA's 2016 rulemaking, and even if it had, the optional provisions would not apply to the GTP, pipeline, compressor stations heater, and Liquefaction plant because they are all part of natural gas transmission, not natural gas production. This rule is where EPA included an optional approach to the aggregation of oil and gas production activities.¹⁶⁴ That rule expressly excludes both natural gas transmission operations like the Mainline and the emitting units at the beginning, end and along the pipeline. As EPA explained, the rule was designed to address the "unique" circumstances of the gas production industry - circumstances absent from the gas transmission and LNG facilities.¹⁶⁵ In fact, EPA's 2016 rule clarifies only the term "adjacent" *Id.* at 35633, what is "contiguous," was not changed.¹⁶⁶

Additionally, the unique facts of the AK LNG Project are clearly different from the discussion and examples provide in EPA's 1980 preamble where it promulgated amendments to the PSD regulations, where it formulated a new definition of source to include the SIC two-digit categories to classify each source. EPA's preamble language ignored the fact that pipelines are pollutant-emitting activities – not just methane, but also VOCs.¹⁶⁷ Notably, methane emissions

¹⁶¹ See Jordan Cove Energy Project, L.P., LNG Terminal, Type B State New Source Review Application, prepared for Jordan Cove Energy, LLC., at 3 (Sept. 2017), available at <https://www.oregon.gov/deq/Programs/Documents/JCEPAQPermitAppl2017.pdf>.

¹⁶² See Golden Pass Products, LNG Terminal PSD Permit Application (Dec. 2013) at 4-1 to 4-2.

¹⁶³ See FERC "LNG," available at <https://www.ferc.gov/industries-data/natural-gas/overview/lng>; FERC, "LNG Maps Exports," available at <https://www.ferc.gov/media/lng-maps-exports>; Cameron LNG, available at <https://cameronlng.com/lng-facility/lng-and-liquefaction/>; Freeport LNG, available at <https://freeportlng.com/>.

¹⁶⁴ See Source Determination for Certain Emission Units in the Oil & Natural Gas Sector, 81 Fed. Reg. 35622, 35630 (June 3, 2016).

¹⁶⁵ *Id.*

¹⁶⁶ *Id.*

¹⁶⁷ 45 Fed. Reg. 52676, 52695 (Aug. 7, 1980) (For example, in this example from EPA, it characterized a multistate pipeline, "Many commenters urged EPA to clarify the extent to which the final definition of those terms

were not regulated by the CAA in 1980, and therefore, examples EPA offered in the preamble did not consider fugitive methane emissions from natural gas pipelines.¹⁶⁸ Natural gas pipelines are also sources of volatile organic compound emissions, which EPA's 1980 preamble statement did not recognize. Furthermore, there is no indication whatsoever that EPA's hypothetical "long-line operation" was – like the Mainline Pipeline – itself a pollutant emitting activity. In fact, that EPA believed a clarification on this point to be unnecessary suggests precisely the opposite: the preamble merely describes a smattering of discrete activities, separated by many miles, unconnected by any intervening pollutant-emitting activities.¹⁶⁹ Therefore, it would be unreasonable to suggest that those examples are relevant to the source determination for the AK LNG Project,¹⁷⁰ particularly given the fact-specific nature of source determinations, which EPA repeatedly noted in its determinations.

Finally, it would also be unreasonable to suggest that only two factors in EPA's 1980 preamble discussion regarding "common sense notion of 'plant'" and the definition of source for PSD purposes "must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of 'building,' 'structure,' 'facility,' or 'installation,'" should be used in the AK LNG Project analysis. Not only are they just two of the three boundaries that in EPA's view, it thought were set by the court in *Alabama Power*, more importantly, the first boundary EPA identified is that the definition of source for purposes of PSD "must carry out reasonably the purposes of PSD."¹⁷² Section 160 of Part C of the Clean Air Act lists the following purposes of the Prevention of Significant Deterioration Program:

(1) to protect public health and welfare from any actual or potential adverse effect which in the Administrator's judgment may reasonably be anticipated to occur from air pollution

encompasses the activities along a "long-line" operation, such as a pipeline or electrical power line. For example, some urged EPA to add to the definition the provision that the properties for such operations are neither contiguous nor adjacent. To add such a provision is unnecessary. EPA has stated in the past and now confirms that it does not intend "source" to encompass activities that would be many miles apart along a longline operation. For instance, EPA would not treat all of the pumping stations along a *multistate pipeline* as one "source.") (emphasis added)

¹⁶⁸ EPA regulated methane from oil and gas sources, including fugitive emissions from compressor stations, under section 111 of the Clean Air Act in 2016. 40 CFR 60.5360a-.5432a (2016). Though EPA recently deregulated methane and removed transmission and storage segments under section 111, see *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review*, 85 Fed. Reg. 57,018 (Sept. 14, 2020), that action has is currently being challenged in Federal court. See *State of California, et al v. Wheeler*, Case No. 20-1357 (D.C. Cir. 2020).

¹⁶⁹ Furthermore, there is nothing in EPA's 1980 preamble to suggest that its language has independent legal effect. In light of the examples of EPA's historical single source determinations presented above, it is clear EPA did not intend to bind either itself, states or regulated entities by the preamble language. Additionally, it is improper to consult the preamble to rule, because the meaning of the rule is clear on its face.

¹⁷⁰ Examples of inapposite phrases in EPA's preamble include (1. "EPA has stated in the past and now confirms that it does not intend 'source' to encompass activities that would be many miles apart along a longline operation." 2. "For instance, EPA would not treat all of the pumping stations along a multistate pipeline as one 'source.'" 3. "EPA is unable to say precisely at this point how far apart activities must be in order to be treated separately. The Agency can answer that question only through case-by-case determinations. One commenter asked, however, whether EPA would treat a surface coal mine and an electrical generator separated by 20 miles and linked by a railroad as one "source," if the mine, the generator, and the railroad were all under common control. EPA confirms that it would not. First, the mine and the generator would be too far apart. Second, each would fall into a different two-digit SIC category.") *Id.*

¹⁷¹ *Id.* at 52694-52695 (and offering that in EPA's view, the court in *Alabama Power*, set such boundaries).

¹⁷² *Id.*

or from exposures to pollutants in other media, which pollutants originate as emissions to the ambient air), notwithstanding attainment and maintenance of all national ambient air quality standards;

(2) to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value;

(3) to ensure that economic growth will occur in a manner consistent with the preservation of existing clean air resources;

(4) to assure that emissions from any source in any State will not interfere with any portion of the applicable implementation plan to prevent significant deterioration of air quality for any other State; and

(5) to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process.

Section 160 of the Clean Air Act, 42 U.S.C. § 7470.

A decision not to treat the AK LNG Project as one source is contrary to the purpose of the Act. For example, without conducting the required PSD analysis, the FEIS for the AK LNG Project incorrectly suggests that the Mainline Pipeline compressor stations and heater station would be considered new minor sources under the PSD program.¹⁷³ Moreover, the GTP was previously issued a separate major source PSD permit by ADEC in August 2020, which occurred without ADEC conducting the required analysis of what constitutes the source. If the AK LNG Project is split up into a major and minor source construction permits, then the purposes of the PSD program, including the requirement to assure that “any decision to permit increased air pollution...is made only after careful evaluation of *all of the consequences* of such a decision...”¹⁷⁴ will not be met.¹⁷⁵ In addition, the Liquefaction plant and the compressor stations will impact the same public lands including Class I areas and thus, to ensure that the air quality in the affected national parks and wilderness areas are preserved, protected, and enhanced, it is imperative that all of the facilities that are truly part of the same project be permitted as such. Indeed, several compressor stations are right on the doorstep for Denali. If separate permits were issued for each emitting activity, that would mean some sources would receive minor source permits (e.g., all the compressor stations and heater station) and would not be subject to the more rigorous analysis, more stringent BACT emission limitations and permits with more robust terms and conditions for such elements as monitoring recordkeeping and reporting.¹⁷⁶ ADEC cannot

¹⁷³ See March 2020, Federal Energy Regulatory Commission, Final Environmental Impact Statement, Alaska LNG Project, Volume 3 at 4-922.

¹⁷⁴ Section 160(5) of the Clean Air Act, 42 U.S.C. §7470(5) (emphasis added).

¹⁷⁵ Furthermore, the minor sources would evade the PSD BACT analysis and review requirements.

¹⁷⁶ Additional differences between PSD and minor source permits include: minor sources escape the requirement to obtain a Title V permit (which means no opportunity for the public to review and comment on the ongoing operations, gap-filing for monitoring, recordkeeping and reporting of emissions, and other requirements); there is no involvement for the FLMs in minor source permits; 18 AAC 50.540(l) includes provisions for exemption of minor

ensure that the purposes of the PSD program would be met under such a scenario. Finally, it is undisputed that the aboveground¹⁷⁷ and underground pipeline itself will emit air pollution in the form of greenhouse gases, including methane, and if it is not aggregated with the rest of the AK LNG Project, it would evade the substantive requirements of the PSD program—including, most notably, a review of technologies to control greenhouse gas emissions from its above-and below-ground components.¹⁷⁸ This is not, then, a case where the practical advantages of administering multiple permits at no real cost to environmental quality justifies a purely technical departure from the definition of a single "source."¹⁷⁹ ADEC must follow the plain language of its own regulations and consistent with the purposes of the Act, treat all facilities associated with the AK LNG Project as one source for purposes of PSD permitting. Finally, until such time as AGDC substantially amends its PSD permit application to include the missing analysis and information, the ADEC cannot approve the proposal in conformance with Alaska's SIP or the Clean Air Act.

B. ADEC's Analysis Fails to Include a Detailed Schedule for Construction and Operation of the Sources.

The PSD permit application must include, at a minimum, information on the location, design capacity, and *typical operating schedule of the source, a detailed schedule for construction*, and a description of the control technology that is proposed as BACT,¹⁸⁰ and these requirements are in Alaska's regulations.¹⁸¹

ADGC failed to include the detailed construction schedule in its application for the proposed Liquefactions plant, as well as the other sources that comprise this source. Given the large number of emitting sources and the impact of those sources on the environment, the construction schedule and associated emissions over the construction timeline are essential to evaluate air quality and other impacts, indeed these PSD provisions are interdependent. Because emissions from construction differ from those once the sources are operating, the permit application must include schedules for both sets of activities. Without the construction schedule ADEC's proposed action fails to meet these regulatory requirements, it cannot issue a permit based on missing information and analysis. Moreover, without this essential information, the agency simply does not have factual information to conduct the required modeling analysis.

sources from the one-hour nitrogen dioxide standard under certain circumstances; if a minor permit is issued under the "fast track" procedure, 18 AAC 50.542 limits the opportunity for public comment via a shortened initial public comment period of 15 days and of the public requests the full 30-day period, ADEC decides whether to grant more time (notably here, there are no criteria upon which ADEC must make such decisions).

¹⁷⁷ There will be some aboveground crossings of two water bodies, active faults, and the offshore portion of the Cook Inlet. FEIS at 2-13.

¹⁷⁸ See also, generally, *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) (holding that major sources of greenhouse gases are subject to the PSD program only if considered a major source of one or more criteria pollutants).

¹⁷⁹ Cf. *In the Matter of BP Exploration (Alaska), Inc. Gathering Center #1*, Order on Petition (April 20, 2007) (declining to overturn state permitting agency's "single source" determination in part because petitioner failed to demonstrate actual consequences on air quality as a result of the determination), available at https://www.epa.gov/sites/production/files/2015-08/documents/bpexploration_response2004.pdf, *aff'd sub nom. MacClarence v. EPA*, 596 F.3d 1123 (9th Cir. 2010).

¹⁸⁰ *Alabama Power* at 351. (emphasis added)

¹⁸¹ 18 AAC 506.040(h)(12), adopting by reference 40 C.F.R. § 52.21(n)(1).

The PSD regulations provide for “issuing a comprehensive permit for construction projects that are to be completed in phases, thus avoiding a separate permit proceeding for each phase.”¹⁸² When construction projects are to be completed in phases, as is contemplated here, the PSD regulations allow a permitting agency to grant a comprehensive permit for a phased construction, thus avoiding a separate permit proceeding for each phase, if the permit provides the following:

- (1) independent BACT review of each phase of the project,
- (2) actual commencement of construction of each phase within eighteen months of the target date specified in the original application, with a variance procedure available only for the commencement date of the first phase of the project, and
- (3) avoidance of any interruption in the course of construction of any particular phase for longer than eighteen months.¹⁸³

Thus, one option is for the AK LNG Project to see a comprehensive permit for construction of all the sources that are part of the PSD permit to avoid PSD permitting for each phase.

Regardless of whether a comprehensive permit or individual permits are issued, the PSD regulations require that a permittee commence construction within 18 months of receiving a permit. This requirement is in part to account for improvements in emission control technology and BACT determinations. Construction of the AK LNG Project is planned over a period of at least eight years, and ADEC’s analysis did not take into consideration *when* emissions will occur from the Liquefaction plant, much less the numerous other emitting units that comprise the source. Therefore, ADEC’s PSD permits for sources that are part of the AK LNG Project, including the Liquefaction plant, must include permit terms and conditions that reflect the 18-month requirement, and that no later than 18-months prior to commencement of construction of each source ADEC review, and modify as appropriate, the BACT determination. ADEC’s review process must include public notice and an opportunity for public review comment.

C. The Proposed Permit Lacks BACT Emission Limitations for the Fugitive Emissions

¹⁸² *Id.* See 18 AAC 506.040(h)(8), adopting by reference 40 C.F.R. § 52.21(j)(4) (“For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.”)

¹⁸³ *Alabama Power* at 409 (further explaining that “Section 165 of the Clean Air Act states that no major emitting facility, on which construction is commenced ... may be constructed in any clean air area unless PSD permitting requirements are met. For an industrial project that is to be constructed in stages, as over a period of years, the meaning of the phrase “construction is commenced” may determine whether and to what extent PSD preconstruction review applies. EPA has developed the practice of issuing a single, comprehensive PSD permit for an entire project with special conditions pertaining to each phase of construction.”) *Id.*

Once a facility's potential to emit exceeds the major source threshold, its fugitive emissions—or those that cannot “reasonably pass through a stack, chimney, vent or other functionally equivalent opening”¹⁸⁴—are subject to BACT the same as all other emissions. “[A] major emitting facility is subject to the requirements of section 165 for each pollutant it emits irrespective of the manner in which it is emitted.”¹⁸⁵

Neither AGDC's Application nor ADEC's efforts includes a BACT analysis for fugitive emissions from any source at the Liquefaction plant. Furthermore, as discussed above,¹⁸⁶ the Application and ADEC's analysis neither includes the Mainline Pipeline nor methane and VOC emissions from the pipeline. BACT should be required for fugitive emissions from the other AK LNG Project emitting sources as well. PSD applications must include the required analysis and include enforceable emission limits. For example, EPA Region VI's 2012 Statement of Basis for the Channel Energy Center in Pasadena, Texas—expressly lists “Fugitive Natural Gas emissions from piping components” as among the “devices . . . subject to th[e] GHG PSD permit”¹⁸⁷ and then proceeds to conduct a substantive BACT analysis for fugitive emissions, ultimately arriving at an enforceable emission limit.¹⁸⁸ Other greenhouse gas PSD permits incorporate similar limits.¹⁸⁹ Presumably because “the magnitude of fugitive emissions depends on how many . . . valves, connectors and pumps [] are present,”¹⁹⁰ BACT sometimes requires numeric limits on components in addition to a weight-based limitation.¹⁹¹ The omission of any similar analysis or enforceable limit here renders the draft permit invalid.¹⁹²

¹⁸⁴ 18 AAC 50.990(40), 40 C.F.R. § 51.166(b)(20). Moreover, the PSD requirements apply to “apply to each regulated pollutant that a “major” source emits in “significant” amounts, e.g., 40 C.F.R. § 52.21(j). The regulations do not distinguish between stack and fugitive emissions for this purpose. *Masonite* at 582, citing 54 Fed. Reg. 48870 (Nov. 28, 1989).

¹⁸⁵ *Alabama Power* at 369.

¹⁸⁶ *Supra* at 20-22, Emissions from the Mainline Pipeline are incomplete and inaccurate.

¹⁸⁷ See Environmental Protection Agency Region VI, Statement of Basis for PSD Permit for the Channel Energy Center, Permit No. PSD-TX-955-GHG at 7 (Aug. 2012), available at https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/calpline_energy_sob.pdf.

¹⁸⁸ See *id.* at 25–26.

¹⁸⁹ See, e.g., Environmental Protection Agency Region VI, Statement of Basis for PSD Permit for Tenaska Brownsville, Permit No. PSD-TX-1350-GHG (Oct. 2014), available at <https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/tenaska-brownsville-revision-summary01232015.pdf>; Environmental Protection Agency Region VI, Statement of Basis for PSD Permit for Thomas C. Ferguson Plant, Permit No. PSD-TX-1244-GHG (Nov. 11, 2011), available at https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/lcra_revisions_summary.pdf. See also *Consolidated Environmental Management, Inc.*, Petition Number VI-2010-05, VI-2011-06 and VI-2012-07, at 54 (E.P.A. Jan. 30, 2014) (declining to object to permit that “include[d] state-of-the-art ambient monitoring for fugitive emissions, such as additional monitoring and deposition gauges . . . intended to provide for information from which numeric emission levels can be calculated”), available at https://www.epa.gov/sites/production/files/2015-08/documents/nucor_steel_response_2012_zennoh.pdf.

¹⁹⁰ See Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56593, 56612 (Sept. 18, 2015) (Proposal).

¹⁹¹ See Environmental Protection Agency Region VI, Statement of Basis for PSD Permit for Thomas C. Ferguson Plant, Permit No. PSD-TX-1244-GHG, 40 (Nov. 11, 2011), available at https://www.epa.gov/sites/production/files/2015-08/documents/nucor_steel_response2012.pdf (limiting facility to “520 gas/vapor valves, 1460 gas/vapor flanges and 3 gas/vapor compressors”).

¹⁹² See *Cash Creek Generation*, Petition No. IV-2010-4, at 11 (E.P.A. June 22, 2012) (Cash Creek II) (objecting to issuance of operating permit because the “BACT analysis that appeared in the permit application . . . omitted any discussion of . . . requirements serving as BACT for fugitive CO emissions”), available at https://www.epa.gov/sites/production/files/2015-08/documents/cashcreek_response2010.pdf.

ADEC's analysis and draft permit only covers fugitive emissions from dust¹⁹³ and fails to evaluate and include BACT requirements for other fugitive emission sources. For example, the Liquefaction plant would include emissions sources characterized as "fugitive emissions from pipe flanges, valves, and valve stems."¹⁹⁴ Indeed, the Liquefaction plant would also include piping components, including connectors, pumps, and compressors. All of these components leak unless the Liquefaction plant uses leakless components.

BACT requires the maximum degree of control from a technically feasible technology unless there is a demonstrated adverse economic, energy or environmental impact. The BACT analysis should consider most effective control technology: leakless technology. While leakless technology is used to control leaks of toxic and hazardous gases, this is certainly not its only use. Leakless technologies are widely used in petrochemical facilities. They are not restricted to highly toxic or otherwise hazardous streams. Leakless technologies are used, for example, in every petroleum refinery in California's Bay Area Air Quality Management District (BAAQMD). Preventing leaks saves money and prevents adverse air quality impacts. It is a reasonable and technically feasible control technology.

ADEC provides no evidence in its proposal indicating that installing and operating leakless technology, LDAR, or remote sensing would cause uniquely excessive costs at the Liquefaction plant compared to other similar facilities. A widely used technology, such as leakless components or LDAR, cannot be eliminated on cost effectiveness grounds unless unique circumstances are demonstrated.¹⁹⁵ Conventional LDAR methods, used in many thousands of facilities throughout the petrochemical and refining industries, are cost effective to detect natural gas leaks, and should be cost effective here. The BAAQMD, for example, supervises LDAR programs at five refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under its Regulation 8, Rule 18 (Reg 8-18).¹⁹⁶ Not only does ADEC fail to analyze BACT for natural gas leaks, it also fails to consider leaks of hazardous air

¹⁹³ FERC's FEIS explains that to minimize impacts on wind-erodible soils, AGDC developed a Project Fugitive Dust Control Plan that outlines dust control measures to be used as needed during construction and operation of the LNG Plant as discussed above in section 4.2.4. FEIS Volume 1, at 4-92, 4-118 ("AGDC's implementation of dust control measures outlined in the Project Fugitive Dust Control Plan, including: using dust control abatement measures as needed during construction and operation; applying water to affected unpaved roads and staging areas; applying approved dust suppressants such as calcium chloride or water/magnesium chloride mixture; and reducing speed limits on unpaved roads."). ADEC's proposed permit is inconsistent with the FEIS because fails to include provisions limiting dust suppressants to those that are "approved and also lacks provisions reducing speeds on unpaved roads." Moreover, ADEC's proposed permit conditions (10.1) only require fugitive dust control for five months (May through September), while there are no such temporal limitations in the FEIS. Further, ADEC fails to provide rationale for the temporal restriction.

¹⁹⁴ FEIS, Vol. 3 at 4-959.

¹⁹⁵ See NSR Workshop Manual at B.44, B.45.

¹⁹⁶ Bay Area Air Quality Management District, Regulation 8, Organic Compounds, Rule 18, Equipment Leaks, available at <https://www.baaqmd.gov/~media/dotgov/files/rules/reg-8-rule-18-equipment-leaks/documents/rg0818.pdf?la=en>.

pollutants and refrigerant losses.¹⁹⁷ Further, there is no analysis of fugitive emissions from LNG storage and containment.¹⁹⁸

D. The Proposed Permit Fails to Demonstrate Plant Will Comply with all Federal Standards

The statutory PSD program provides, inter alia, that no construction on a major emitting facility may be commenced after August 7, 1977 in an area designated under the PSD classification system unless:

[T]he owner or operator of such facility demonstrates that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of (C) any other applicable emission standard or standard of performance under this (Act.)

(42 U.S.C. § 7475(a)(3). This includes, notably, any applicable new source performance standard (NSPS).¹⁹⁹ Similarly, 42 U.S.C. § 7475(a)(4), requires the proposed facility to be subject to the best available control technology for each pollutant subject to regulation under the Act. Under the statutory definition of the term “best available control technology,” it is stated that:

In no event shall application of “best available control technology” result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 7411 (which defines the standards of performance for new stationary sources) of this title.

42 U.S.C. § 7479(3).²⁰⁰

¹⁹⁷ FEIS Vol. 1 at 2-28(Following pre-treatment, three liquefaction-processing units, or trains, would liquefy the natural gas. AGDC would use the Propane Precooled Mixed Refrigerant (AP_C3MR™) Process, an Air Products and Chemicals, Inc. patented technology. In this process, the treated natural gas would be pre-cooled in successive stages of propane chilling. Subsequent cooling and liquefaction would occur by heat exchange against mixed refrigerant in the main cryogenic heat exchanger. Prior to entering the main cryogenic heat exchanger, the mixed refrigerant would be cooled/partially condensed. The refrigeration for this pre-cooling would occur by multiple stages of propane chilling. Each of the three liquefaction trains would include two refrigerant compression strings installed in parallel, driven by two natural gas turbines. The propane and mixed refrigerant would be cooled using air coolers. Fans would pull the air over tube bundles, in turn cooling within the tube bundles. Air-cooled LNG plants are influenced by air temperature variation. The air cooler inlet air-dry bulb design temperature would vary between a low ambient of 2°F and a high ambient of 61°F.).

¹⁹⁸ Furthermore, any suggestion by ADEC that the audio/visual/olfactory (AVO) leak detection method is the most effective method to detect leaks is simply wrong. Relying solely on AVO is not reasonable. The proposed plant is large and it is unreasonable to rely on an individual “sniff-test” during inspection rounds to detect all leaks from a variety of pollutants at a Liquefaction Plant.

¹⁹⁹ 40 C.F.R. § 52.21(j) (requiring that PSD program ensure that all “major stationary source[s] . . . meet each . . . applicable emissions standard and standard of performance under 40 CFR parts 60 and 61”). *See also Northern Plains Resource Council v. Environmental Protection Agency*, 645 F.2d 1349, 1352–53 (9th Cir. 1981) (A permitting authority “would clearly be acting contrary to the statutory PSD program in issuing a PSD permit to a facility which would produce emissions in excess of an applicable new source performance standard.”). *See also* 18 AAC 50.040(h)(8), adopting by reference 40 C.F.R. § 52.21(j).

²⁰⁰ *See* Parallel regulatory definitions of BACT, 18 AAC 50.040(h)(4), adopting by reference the definitions in 40 C.F.R. § 52.21(b)(“12) In no event shall application of best available control technology result in emissions of any

ADEC's proposed action fails to contain an analysis of whether any NSPS apply, and if so, whether the proposed Liquefaction plant will meet those standards. Based on analyses and determinations by other permitting authorities for similar facilities, there appear to be several NSPS that might apply.^{201, 202} ADEC is prohibited from issuing the permit for the proposed Liquefaction plant until such an analysis is conducted and a determination made that the BACT determinations will not exceed the NSPS standards.²⁰³ Furthermore, as discussed in the Stamper Report, ADEC's proposed BACT limits for the diesel-fired units (the fire pump and the and auxiliary air compressor engine) are less stringent than the applicable NSPS standards.²⁰⁴ Finally, the Order issued to the AK LNG Project by FERC indicates that "AGDC would implement various measures to reduce construction emissions, including ... use of electric generators in compliance with New Source Performance Standards (NSPS) Subpart III."²⁰⁵

E. ADEC's Public Notice Suggests Its Proposed Approval includes Hazardous Air Pollutants, and There is no Supporting Analysis.

Additionally, while ADEC's notice for this proposed approval indicates the Liquefaction Plant is subject to the construction permitting requirements for hazardous air pollutants (HAPs), there is nothing in the proposal covering these pollutants and the requirements. ADEC's public notice explains that "[t]he project is also classified under 18 AAC 50.316 as a major source of Hazardous Air Pollutants for formaldehyde and ethylbenzene."²⁰⁶ Similarly, the PreTAR explains that "AGDC submitted this analysis in support of their 1 May, 2018 air quality control permit application (AQ1539CPT01) submitted under the Prevention of Significant Deterioration (PSD) requirements listed in 18 AAC 50.306 and the major source of hazardous air pollutant (HAP) requirements listed in 18 AAC 50.316."²⁰⁷ The rule cited by ADEC includes the requirements for preconstruction review for construction or reconstruction of a major source of hazardous air pollutants,²⁰⁸ which suggests ADEC's proposed permit action is also intended to cover the CAA's hazardous air pollutant requirements, which it does not.

pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61."); , 18 AAC 50.040(h)(4), adopting by reference the definitions in 40 C.F.R. § 52.21(b) ("(16) *Allowable emissions* means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following: (i) The applicable standards as set forth in 40 CFR parts 60 and 61"); AAC 50.040(h)(8), adopting by reference 40 C.F.R. § 52.21(j) ("*Control technology review*. (1) A major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR parts 60 and 61.")

²⁰¹ NSPS for Combustion Turbines Subpart KKKK, NSPS Subpart Db, NSPS Subpart IIII, NSPS Subpart Kb, NSPS Subpart OOOOa.

²⁰² See, e.g., FEIS at 4-925 – 4-927.

²⁰³ Additionally, the FEIS "determined that" several NSPS would be "applicable to one of more of the Project facilities," and ADEC did consider this information. *Id.* at 4-925 – 4-927.

²⁰⁴ See Stamper Report at 31-33.

²⁰⁵ FERC Order ¶ 202.

²⁰⁶ Public Notice, State of Alaska, Department of Environmental Conservation Alaska Gasline Development Corporation Liquefaction Plant.

²⁰⁷ PreTAR at 1.

²⁰⁸ 18 AAC 50.316. Preconstruction review for construction or reconstruction of a major source of hazardous air pollutants.

EPA established NESHAPs in 40 C.F.R. Parts 61 and 63 to control the emissions of Hazardous Air Pollutants (HAPs). NESHAP regulations include emission standards or work practices for specific types of equipment located at a HAP source. A HAP major source is a facility with a potential to emit 10 tpy or more of a single HAP or 25 tpy or more of a combination of HAPs. Both AGDC and ADEC conclude that the proposed Liquefaction plant is a major source of HAPs, and AGDC's permit application provides information on the NESHAPs that it determined applies. AGDC explains that:

Information related to Liquefaction plant applicability of Part 63 NESHAPs is provided in Resource Report 9, Section 9.2.6.7, starting on page 9-94, and in RR9 Appendix H Project NSPS, NESHAPs and RMP Applicability Analysis, both included as Attachment 4. ... See 18 AAC 50.316 discussion below for 63.5(d)(1)-(2) requirements. Please note that AK LNG has refined NESHAPs applicability analysis since RR9 was submitted to FERC in April 2017. The Project now believes requirements of 40 C.F.R. 63, subpart EEEE do apply to the Liquefaction plant, while those of 40 C.F.R. 63, subpart HH do not

(a) Applicability. The owner or operator of a major source of hazardous air pollutants subject to a standard under 40 C.F.R. Part 63, adopted by reference in 18 AAC 50.040, must obtain a construction permit before (1) constructing a new major source of hazardous air pollutants subject to that standard; (2) reconstructing a major source of hazardous air pollutants subject to that standard; or (3) reconstructing a major source of hazardous air pollutants in a way that causes the source to become an affected source that is major-emitting under 40 C.F.R. Part 63 and subject to that standard.

Definitions. The term "administrator" as used in 40 C.F.R. 63.5(d) - (e), adopted by reference in 18 AAC 50.040, means "department" for the purposes of this section.

(c) Procedures for preconstruction approval. An application for a construction permit required under this section must be prepared and submitted in accordance with 40 C.F.R. 63.5(d), adopted by reference in 18 AAC 50.040.

After receiving a complete application,

(1) the department will prepare a report that contains a preliminary decision to approve or deny the permit application; the department will make a decision to issue the permit only if the department determines that the criteria of 40 C.F.R. 63.5(e)(1), adopted by reference in 18 AAC 50.040, are met;

(2) if the department makes the preliminary decision to deny the permit application, the owner, operator, or permittee may submit additional information for the department to consider before the department makes a final decision, as follows:

(A) after consulting with the applicant, the department will specify dates by which the applicant must submit any additional information under this paragraph;

(B) within 60 days after receiving the additional information, the department will (i) make a preliminary decision to approve or approve with conditions; or (ii) take a final permit action and deny the permit application for cause; (3) if the department makes a preliminary decision to approve the permit application, the department will (A) prepare a draft permit; (B) provide at least 30 days for the public to comment, and upon its own motion or upon a request in accordance with 18 AAC 15.060, will hold a public hearing on the application as described in 18 AAC 15.060(d) - (h); and

(C) make available for public review the materials submitted by the applicant and a copy of the proposed permit in at least one location within the area known or expected to be affected by the stationary source as proposed; (4) if the department makes a decision to issue a final permit, the department will issue the permit consistent with AS 46.14.170.

(d) Permit Content. In a permit under this section, the department will include terms and conditions that (1) reference specific applicable requirements under each applicable subpart of 40 C.F.R. 63, adopted by reference in 18 AAC 50.040; (2) require reporting in accordance with 18 AAC 50.235 - 18 AAC 50.240; and (3) require payment of fees in accordance with 18 AAC 50.400 - 18 AAC 50.420.

(e) Notification. For each notification that the owner or operator is required to send to the administrator under 40 C.F.R. 63.9, adopted by reference in 18 AAC 50.040, the owner or operator shall also send a copy of the notification to the department.

apply to the Liquefaction plant. This differs from Table 9.2.6-6 of Resource Report 9, which indicates applicability of these two subparts is “TBD” (to be determined). AK LNG provided the Department a revised version of Table 9.2.6-6 in response to response RFI-538-014 submitted in response to the Department’s March 6, 2018 incompleteness finding for the GTP construction permit application.²⁰⁹

The Application further remarks that “18 AAC 50.316(a) is the process in the Alaska State Implementation Plan for meeting 40 CFR 63.5(d)(1)-(2) requirements related to application for approval of construction of a HAP-Major Source”.²¹⁰

Contrary to the statement made in the Application, ADEC’s authority for acting on applications requesting approval for construction of major sources of HAPs is not under the SIP. Rather, ADEC’s authority for acting on the NESHAP and MACT requirements falls under section 112 of Act, and is a result of EPA’s action on ADEC’s Operating Permits Program, which included action on the State’s Section 112(l) Program Submittal.²¹¹ EPA’s action identified the authority found in the Alaska regulations, which it approved and found met the requirements for adequate legal authority for Alaska to implement and enforce section 112 approval.²¹²

The NESHAP identified by AGDC is 40 C.F.R. 63, subpart Eeee are the National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), which “establishes national emission limitations, operating limits, and work practice standards for organic HAPs emitted from organic liquids distribution (OLD) (non-gasoline) operations at major sources of HAP emissions.”²¹³ This NESHAP “also establishes requirements to

²⁰⁹ Alaska LNG, Alaska LNG Liquefaction Construction Permit Application, Project Information Form Attachment 1, Information Reference Table for Alaska LNG Liquefaction Plant (March 2018), Citation 63, PDF at 4.

²¹⁰ *Id.* at 5.

²¹¹ 61 Fed. Reg. 49091, 49094 (Sept. 18, 1996)(EPA’s proposal explained, “[a]uthority for section 112 implementation. Except as discussed below in section B.1.iii. and the section proposing action on Alaska’s section 112(l) submittal, Alaska has demonstrated adequate legal authority to implement and enforce section 112 requirements through the title V permit. Alaska has incorporated by reference most of the regulations that have been promulgated by EPA under section 112 of the Act that may affect Alaska sources. See 18 AAC 50.040(b) (relevant standards under 40 C.F.R. part 61); 18 AAC 50.040(c) (relevant standards under 40 C.F.R. part 63); AS 46.14.130(a) and 18 AAC 50.300 to 50.322

preconstruction review of major sources of hazardous air pollutants (“HAPs”).”) EPA’s final action on ADEC’s authority to implement the Section 112 requirements further explained that, “In the September 18, 1996, Federal Register notice, EPA noted that Alaska lacked authority to implement several section 112(l) requirements, but believed that these deficiencies were not so serious as to warrant disapproval. 61 FR 49095. Alaska commented that the September 17, 1996, final version of the adopted State rules included the adoption by reference of 40 C.F.R. § 61.150 and 40 C.F.R. § 61.154 and asked that EPA remove the specific interim approval conditions related to these provisions. EPA agrees that the adoption of these two provisions remedies the deficiencies regarding implementation and enforcement of the asbestos NESHAP for waste disposal and active waste disposal sites.[FN1] Alaska has still not adopted, however, the provisions of 40 C.F.R. part 61, subpart I (radionuclide NESHAP for facilities licensed by the Nuclear Regulatory Commission). Therefore, the State still lacks sufficient authority to implement all applicable section 112 requirements for title V sources in Alaska. As such, EPA concludes that the Alaska program must be granted interim rather than full approval because of this deficiency.”) *See also* 61 Fed. Reg. 64463, 64465 (Dec. 5, 1996)(EPA’s Final Approval in Part and Disapproval in Part, Section 112(l) Program Submittal).

²¹² *Id.*

²¹³ 40 C.F.R. § 62.2330.

demonstrate initial and continuous compliance with the emission limitations, operating limits, and work practice standards.”²¹⁴ Other NESHAPs may apply.²¹⁵

Furthermore, ADEC’s Preliminary TAR acknowledges that the “project is also classified under 18 AAC 50.316 as a major source of HAPs for formaldehyde and ethylbenzene,”²¹⁶ but it provides no analysis to determine what or whether any hazardous air pollutant standards apply, and whether any other HAPs are emitted. Therefore, if ADEC’s proposal is intended to cover the construction permitting requirements for HAPs, it does not.

V. ADEC’s Proposed BACT Determinations Are Flawed and Incomplete and ADEC’s Proposed Emission Limitations Fail to Reflect BACT

The AGDC’s proposed Liquefaction plant - and the Alaska LNG Project - must comply with the PSD BACT requirements as it is located in an attainment or unclassifiable area.²¹⁷ The Clean Air Act requires states with regions in attainment of the national ambient air quality standards to guard their attainment standards by implementing the PSD provisions found in sections 160 to 165 of the Clean Air Act. As Ms. Stamper’s report explains, a final PSD permit issued by ADEC must impose emission limits reflective of BACT for each regulated air pollutant that Alaska LNG Project has the potential to emit in significant amounts,²¹⁸ which include nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), sulfur dioxide (SO₂), particulate matter (PM) including PM₁₀ and PM_{2.5}, and greenhouse gases (GHG).^{219, 220} The PSD regulations define best available control technology as follows:

[A]n emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement

²¹⁴ *Id.*

²¹⁵ For example, other LNG facilities determined that the following apply: 40 C.F.R. § 63, SUBPART ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE), applies to all of the proposed diesel-fired engines. Subpart CCCCCC – Gasoline Dispensing Facilities at Area Sources. Subpart JJJJJJ – Area Source Boiler MACT- Industrial, Commercial and Institutional boilers and process heaters located at area sources of HAPs. NESHAP for Combustion Turbines Subpart YYYYY.

²¹⁶ PreTAR at 2. Furthermore, the draft permit defines the hazardous air pollutant standard acronyms (NESHAP and MACT), but fails to include any of the requirements for these standards in the draft permit. Draft Permit at iii.

²¹⁷ Alaska Nonattainment/Maintenance Status for Each County by Year for All Criteria Pollutants, EPA (Oct. 31, 2020), available at https://www3.epa.gov/airquality/greenbook/anayo_ak.html.

²¹⁸ 40 C.F.R. § 52.21(j)(2), incorporated by reference into Alaska Rules at 18 AAC 50.040(h)(8).

²¹⁹ ADEC’s Preliminary September 11, 2020 Technical Analysis Report (TAR) at 2.

²²⁰ Stamper Report at 3.

methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

40 C.F.R. § 52.21(b)(12), incorporated by reference into Alaska Rules at 18 AAC 50.040(h)(4). Thus, BACT requires an intensive analysis designed to ensure that the facility selects the most stringent available control technology unless it meets the high bar of showing that such technology is not technologically or economically feasible. Failure to provide a reasoned justification for applying a less stringent technology is grounds for federal intervention in ADEC's permitting decisions.²²¹ In promulgating the federal BACT definition²²² upon which the Alaska regulation is based, "Congress intended BACT to perform a technology-forcing function."²²³ ADEC has a legal obligation to follow the regulatory requirements in its SIP, so that consistent with the purposes of the PSD program as outlined by Congress, its permitting decision:

- Protects health and welfare,
- Preserves and protects the air quality in Alaska's national parks and preserves, and national wilderness areas,
- Insures that economic growth will occur in a manner consistent with the preservation of existing clean air resources, and
- Assures that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision.²²⁴

In other words, ADEC must not only follow the regulations, but must do so furthering the goals and purposes of the PSD program. As detailed in Ms. Stamper's Report, ADEC's proposal ignores data, fails to accurately justify assumptions, and misapplies the regulations, which results in allowing the sources at the proposed Liquefaction plant to avoid the required BACT analysis. ADEC's proposal fails to require proper, up-to-date technology to limit the pollutant emissions. By allowing the permit applicant to avoid its legal responsibilities under the PSD Program and escape the legally compliant BACT analysis, ADEC is placing the Class I areas and impacted community members at risk of great harm. The purpose of the PSD permitting process is to

²²¹ See *ADEC* at 490, 502, ("Congress . . . vested EPA with explicit and sweeping authority to enforce CAA 'requirements' relating to the construction and modification of sources under the PSD program, including BACT" and "EPA has supervisory authority over the reasonableness of state permitting authorities' BACT determinations and may issue a stop construction order, under §§ 113(a)(5) and 167, if a BACT selection is not reasonable.").

²²² 42 U.S.C. § 7479(3).

²²³ EPA, Transmittal of Background Statement on "Top-Down" Best Available Control Technology (BACT) (June 13, 1989) at 5 ("EPA Background Statement on BACT"), available at <https://www.epa.gov/sites/production/files/2015-07/documents/topdown.pdf>.

²²⁴ *Id.* Therefore, the "basic purpose" of the PSD program is "simply put, to keep air clean." *Roosevelt Campobello Int'l Park Comm'n v. EPA*, 684 F.2d 1034, 1036 (1st Cir. 1982).

protect the public health and welfare by ensuring that economic growth occurs in a responsible manner.²²⁵ ADEC must redo its analysis, correct the errors, follow the regulatory requirements, and repropose this permit to ensure that the National Parks and Preserves in Alaska and public health are protected.

A. BACT for NO_x for Compressor Turbines (EU 1-6) and Power Turbines (EU7-10)

1. ADEC Failed to Obtain, Consider and Make Available the Necessary Turbine Details.

The AGDC's proposed Liquefied Natural Gas Plant will have several natural gas-fired turbines and neither the AGDC permit application nor the draft permit identify the make and model of the gas turbines to be installed. ADEC's Technical Analysis Report states that the make and model of these turbines are "yet to be selected."²²⁶ As explained in Ms. Stamper's report and supported by examples, knowing the turbine make and model is important to be able to accurately project potential emissions, flue gas exhaust characteristics, and to analyze and set best available control technology (BACT) emission limits.²²⁷ Ms. Stamper's report shows that the two potential turbine options for the large compressor turbine envisioned by the AGDC permit application have very different levels of NO_x emission rates.²²⁸ Furthermore, the net heat rate can also vary between turbine models, which can impact the greenhouse gas (GHG) BACT determination. Furthermore, the capacity of the turbines are also usually identified in the permit – i.e., horsepower rating for compressor turbines and megawatt output rating for power generating turbines. In permits for combined cycle units, the generating capacity of the heat recovery steam generator is specified and, if duct firing is to be included, the heat input in million British Thermal Units per hour (MMBtu/hr) (including for duct firing, if a unit will be so equipped) is specified along with the megawatt generating capacity of the generator with duct firing. Ms. Stamper's report cites to and includes examples of several such permits issued by other states that specifically identify the make and model and also power (horsepower or megawatt rating) of turbines to be installed.²²⁹

The specific make and model of turbines is necessary to evaluate BACT and set BACT emission limits, particularly for NO_x, CO, and GHG. The Draft Permit for the Liquefaction plant uses non-factual "assumptions" regarding the combined cycle power generation turbines, and

²²⁵ 42 U.S.C. §7470, *See also* "What is PSD's Purpose," EPA, (Feb. 2019), <https://www.epa.gov/nsr/prevention-significant-deterioration-basic-information>.

²²⁶ *Id.* at 2 and 19.

²²⁷ NSR Workshop Manual states that "the technical specifications may be considered the core of the permit" and that identification of the emission unit "usually includes a brief description of the source or type of equipment, size or capacity, model number or serial number, and the source's identification of the unit," at H.5. For natural gas-fired turbines, identification of the make and model of the turbine is relevant to the BACT analysis for nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), greenhouse gases (GHG), and other pollutants, as well as potential to emit of the turbines.

²²⁸ Stamper Report at 4.

²²⁹ *Id.* at 4-5.

lacks information on the make and model, horsepower or megawatt rating, as well as hourly heat input. ADEC's Draft Permit similarly lacks information for the heat recovery steam turbine generator, where the MW rating of the must be defined and, if it will be supplemented with duct firing, the heat input to the duct firing must also be specified in the permit as well as the increased generating capacity. This information is essential for ADEC to accurately determine BACT as well as take into account specific flue gas characteristics of the turbines and the level of emissions in the air dispersion modeling required by the PSD regulations.

2. There is no Justification for the NOx Baseline Emission Rate Used in ADEC's Cost Effectiveness Analysis for NOx Controls.

The Liquefaction plant will use six simple cycle natural gas-fired combustion turbines (EU1-6) for the three compressor LNG trains at the Liquefaction plant, with two turbines used for each LNG train.²³⁰ The Liquefaction plant will use four natural gas-fired combustion turbines operated in a combined cycle mode for power generation (EU 7-10).²³¹ ADEC has proposed to only require dry low NOx (DLN) combustors to meet a 9 parts per million by dry volume at 15% oxygen NOx limit (ppmv @ 15% O₂) as BACT for NOx at all of these turbines.²³² ADEC rejected the NOx control of DLN combustors along with selective catalytic reduction (SCR) to meet a NOx limit of 2 ppmv@ 15% O₂ as not cost effective, despite acknowledging that several similar large turbines have installed such controls as BACT. There are several flaws with the ADEC BACT analyses, as discussed in Ms. Stamper's report.

First, to determine cost effectiveness of a particular control technology or technique at an emissions unit, one must know the baseline emissions rate of that unit to assess the amount of pollution that will be reduced with a particular control.²³³ ADEC's baseline emissions rate assumption differs from information in the permit application and while ADEC asserts it followed the permittee's approach, it did not: For the compressor turbines, ADEC considered a NOx rate of 15 ppmv, while AGDC used a 25 ppmv NOx rate. ADEC provides no basis for its lower baseline emissions rate assumption.²³⁴ For the power generating turbines, both ADEC and AGDC assumed a 15 ppmv NOx baseline rate. This assumed baseline NOx rate is unjustified because AGDC has not yet selected a vendor or model of the power turbines to be used at the Liquefaction plant and the draft permit does not require a certain make or model of compressor turbine.²³⁵ Additionally, as discussed in detail in Ms. Stamper's report, AGDC's use of a 25 ppmv@ 15% O₂ NOx baseline for evaluating costs of additional controls at the compressor turbines makes much more sense for a base case emission rate for both the compressor turbines and the power turbines, as compared to ADEC's assumption of a 15 ppmv@ 15% O₂ NOx baseline.²³⁶ Therefore, "[g]iven that the draft permit has not specified a certain turbine make and

²³⁰ PreTAR, Appendix B at 2.

²³¹ *Id.* at 19.

²³² PreTAR (Sept. 11, 2020), Appendix B at 6 and 24.

²³³ Stamper report at 6.

²³⁴ *Id.*

²³⁵ *Id.* at 7.

²³⁶ *Id.* at 6-7.

model and that AGDC has not proposed a turbine make and model, it is reasonable to assume a NOx baseline of 25 ppmv@ 15% O₂.”²³⁷

Finally, to illustrate the importance of this information in calculating emissions, Ms. Stamper’s report calculates a NOx emissions baseline for the compressor turbines and for the power turbines based on a 25 ppmv baseline NOx rate. Ms. Stamper’s calculated baseline of NOx emissions for the compressor turbines was 487.5 tons per year (tpy) per turbine,²³⁸ which is much higher than ADEC’s NOx baseline of 281.8 tpy.²³⁹ For the power generating turbines, Ms. Stamper’s calculated NOx baseline was 168.2 tpy per turbine, which is significantly higher than ADEC’s 104 tpy NOx baseline.²⁴⁰

3. AGDC Assumed Too High an Interest Rate and Too Short a Life of Controls in its NOx Control Cost Effectiveness Analysis.

AGDC apparently assumed both a 7% interest rate and a 5.5% interest rate, along with a 20-year life of controls, in its cost effectiveness analysis of selective catalytic reduction (SCR) and DLN combustors for the compressor turbines and the power turbines.²⁴¹ This was not made clear in AGDC’s March 2018 BACT analysis, because the details of the cost calculations in Appendix B of the company’s BACT analysis were claimed as “Trade Secret in accordance with AS 46.14.520.”²⁴² Given that the make and model of the combustion turbines has not been selected by AGDC nor required by the permit, it does not seem justified to withhold the detailed BACT cost effectiveness calculations for the turbines as trade secrets. Although the details of AGDC’s cost effectiveness analyses were not provided in its permit application, ADEC’s Technical Analysis Report states that AGDC used a 7% interest in its cost calculations that were based on the 6th edition of EPA’s Control Cost Manual and that AGDC used a 5.5% interest rate in its cost calculations that were based on the 7th edition of EPA’s Control Cost Manual.²⁴³ ADEC revised the SCR cost analyses to be based on the current bank prime interest rate of 3.25% and to be based on an SCR life of 25 years for both the compressor turbines and the power turbines.²⁴⁴ EPA’s SCR Cost Spreadsheets that it has made available with its recent updates to its Control Cost Manual²⁴⁵ recommend using the current bank prime lending rate in amortizing capital costs of controls, and it is currently 3.25%.²⁴⁶ EPA’s SCR Control Cost Manual also indicates that an SCR at an industrial boiler should have a useful life of 20-30

²³⁷ *Id.*

²³⁸ *Id.* at 8.

²³⁹ PreTAR, Appendix B at 7 (Table 3-5).

²⁴⁰ Stamper Report at 8.

²⁴¹ ADEC’s Preliminary September 11, 2020 TAR, Appendix B at 6 and at 23.

²⁴² See cover page for Appendix B to Attachment 6, BACT Analysis, April 30, 2018 of AGDC’s Alaska LNG Application.

²⁴³ ADEC’s Preliminary September 11, 2020 TAR, Appendix B at 6 and at 23.

²⁴⁴ *Id.* at 7 and 24.

²⁴⁵ See EPA’s SCR Cost Calculation Spreadsheet available at <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>.

²⁴⁶ See Board of Governors of the Federal Reserve System, Selected Interest Rates (Daily) – H.15 <https://www.federalreserve.gov/releases/h15/>.

years.²⁴⁷ However, for a power plant, EPA states that an SCR should have a useful life of 30 years or more.²⁴⁸

ADEC's assumptions for interest rate and life of SCR at the compressor turbines are consistent with the current (7th edition) version of EPA's Control Cost Manual, although it would be more reasonable to assume a life of SCR of 30 years for the compressor turbines for a few reasons. First, AGDC has stated that the expected life of the entire operation is 30-years (i.e., Prudhoe Bay major gas sales operations are expected to have a 30-year life).²⁴⁹ Second, AGDC has stated that the compressor turbines would be operating at 100% load during normal operations, rather than at variable loads, and such steady state operation would be similar to operations at a base load power plant.²⁵⁰ EPA states that SCR at power plants is expected to have a useful life of 30 years or more. Thus, it would be more reasonable to assume SCRs at both the compressor turbines and the power turbines would last the 30-year life of the LNG plant.

In terms of using an older edition of EPA's Control Cost Manual, EPA revised its Control Cost Manual in 2019, including its chapter on SCR through an extensive notice and comment process, and that is the version that AGDC and ADEC should be using in the BACT cost effectiveness calculations as it is the most up-to-date with current costs for SCR.

4. AGDC and ADEC Assumed Too High a Cost of Ammonia in the SCR Cost Effectiveness Calculation.

ADEC stated that it did not revise the cost of ammonia that AGDC used in its cost calculations. Specifically, ADEC used a cost for aqueous ammonia of \$2.24/gallon (\$0.30/pound) and cited to the "Weekly Fertilizer Review, 4/2015." As Ms. Stamper explains in her Report, EPA's SCR Control Cost Manual chapter assumes a much lower cost for aqueous ammonia of \$0.293/gallon, based on the average for 2016 from the U.S. Geological Survey's Minerals Commodities Summaries, for which EPA provided a weblink.²⁵¹ ADEC did not provide any weblink or other citation for its assumed cost of aqueous ammonia from the Weekly Fertilizer Review. Further, given recent changes in fuel prices, a more recent cost basis for ammonia should have been used.²⁵²

In addition, Ms. Stamper explains that use of anhydrous ammonia in the SCR, rather than aqueous ammonia, should have been evaluated in the cost effectiveness calculations. EPA's Control Cost Manual chapter for SCR states that anhydrous ammonia is more commonly used for SCR controls because it is the least expensive.²⁵³ Indeed, EPA has acknowledged that 80% of EGUs operating SCR use ammonia (and not urea, which is another available SCR reagent) as the reagent for the SCR and, of those, anhydrous ammonia is used over aqueous ammonia by a

²⁴⁷ See EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 80.

²⁴⁸ *Id.*

²⁴⁹ See April 14, 2017 Resource Report No. 1 General Project Description at 1-92, at pdf page 180 of Attachments 1 through 3 of permit application.

²⁵⁰ See 2018 Application Attachments 4 and 5 at pdf page 229.

²⁵¹ *Id.* at pdf page 82. Stamper Report at 9.

²⁵² Stamper Report at 9.

²⁵³ *Id.* See also EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.

ratio of 3 to 1.²⁵⁴ Aqueous ammonia has the highest operating costs because of the cost of transportation.²⁵⁵ Thus, ADEC should have evaluated the costs of using anhydrous ammonia in the cost effectiveness of SCR for the compressor turbines. The U.S. Geological Survey Minerals Commodities Report has the average cost for 2019 at \$230/ton.²⁵⁶ Although EPA's SCR cost calculation spreadsheet made available with the revised 2019 SCR chapter of the Control Cost Manual does not specifically provide for the use of anhydrous ammonia, the spreadsheet can readily be revised to account for the use of anhydrous ammonia as is discussed further below.²⁵⁷

5. AGDC and ADEC Assumed Too High of a Cost for Electricity, Given that the Liquefaction plant Will Be Equipped with Power Generating Turbines.

As presented in Ms. Stamper's Report, in its SCR cost analyses, both AGDC and ADEC assumed a cost of electricity of \$0.16/kW-hr, which apparently is the average cost of electricity for industrial customers in Alaska.²⁵⁸ For SCR cost effectiveness evaluations at utilities, EPA's Control Cost Manual states that the cost for auxiliary power is "the cost to the power plant to generate its electricity, or busbar cost."²⁵⁹ While it is not clear what the cost is for AGDC to generate its electricity with its power turbines, it very likely will be significantly lower than the average electricity cost for industrial consumers in Alaska. EPA's SCR cost spreadsheet uses a default cost of \$0.0361/kWh for electricity cost and states that the user should enter the actual value for electricity cost, if known.²⁶⁰ Thus, AGDC and ADEC should use the actual cost for generation of auxiliary power at its Liquefaction plant in the SCR cost analyses from its planned power generating turbines which presumably should just equate to the fuel cost per kilowatt-hour produced. If that cost is currently unknown, which appears to be the case given all the uncertainties associated with plant design, the EPA default cost of \$0.0361/kWh should be used.

6. Revised Cost Effectiveness Calculations for NOx Controls at the Liquefaction Compressor Turbines and Power Turbines.

To address the deficiencies discussed above, Ms. Stamper prepared revised cost analyses of NOx controls for the compressor turbines and the power turbines using EPA's SCR cost spreadsheet made available with its 2019 revised version of its SCR Chapter of its Control Cost Manual.²⁶¹ Her report provides details on the inputs for her calculations.²⁶²

²⁵⁴ See EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 5.

²⁵⁵ *Id.*

²⁵⁶ U.S. Geological Survey, Minerals Commodities Summaries (2020), at 116, available at <https://www.usgs.gov/centers/nmic/mineral-commodity-summaries>.

²⁵⁷ Stamper Report at 9-10.

²⁵⁸ ADEC's Preliminary September 11, 2020 TAR, Appendix B at 7 and at 23.

²⁵⁹ EPA, Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 33 (fn 17), available at <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>.

²⁶⁰ See EPA's SCR Cost Calculation Spreadsheet at Data Inputs tab, row 56, available at <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>.

²⁶¹ See EPA's SCR Cost Calculation Spreadsheet available at <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>.

²⁶² Stamper Report at 10 and 15.

Ms. Stamper's report estimates the cost effectiveness for an SCR system at each compressor gas turbine that will reduce NOx from the worst case NOx baseline rate of 25 ppmv down to 2 ppmv, which reflects a 92% reduction in NOx across the SCR, to be \$3,483/ton of NOx removed.²⁶³ Ms. Stamper's report estimates the cost effectiveness for an SCR system at each combined cycle power turbine to reduce NOx from 25 ppmv down to 2 ppmv to be \$5,308/ton.²⁶⁴ Ms. Stamper provides ample support that 92% NOx reduction can be achieved with an SCR system, and her report provides numerous examples of simple cycle and combined cycle turbines being required to meet NOx BACT limits in the range of 2.0 (for combined cycle turbines) to 2.5 ppmv (for simple cycle turbines).²⁶⁵ Her report explains that there are readily implementable options to address high exhaust temperatures of simple cycle turbines that could be used to optimize the NOx removal efficiency of an SCR system at a simple cycle gas turbine.²⁶⁶ Therefore, AGDC statements regarding concerns regarding exhaust temperature can be addressed.²⁶⁷

In its BACT discussion for the compressor turbines, AGDC suggests that the 2 ppmv NOx rates have been achieved with SCR at gas turbines "only while under very stringent operational control," and AGDC points to SCR difficulty at Alaska sources "in maintaining uniform ammonia injection rates due to varying ambient temperatures and load ranges."²⁶⁸ However, Ms. Stamper's report points out that SCR has been required as BACT and installed on numerous simple cycle gas turbines that operate as peaking plants (i.e., with varying load ranges) in the United States, that SCR has been successfully implemented in cold climates including other facilities in Alaska, and provides detailed examples demonstrating that in many cases, the NOx limit imposed with SCR was somewhat higher than 2 ppmv, but compliance was required on a very short-term basis with NOx emissions being monitored with continuous emissions monitoring systems (CEMs).²⁶⁹ It is also important to point out that AGDC evaluated cost effectiveness of SCR to meet a 2 ppmv NOx limit,²⁷⁰ and it appears that AGDC obtained a vendor quote, which presumably included a NOx emission rate guarantee, for the SCR systems. In records NPCA obtained on December 4, 2020 from its freedom of information request submitted to ADEC for the FLM communications, the FLMs reference the "vendor quote obtains by AK LNG for their turbines."²⁷¹ The FLM communications further indicate they found several

²⁶³ *Id.* at 16 (Table 6).

²⁶⁴ *Id.* (Table 7).

²⁶⁵ *Id.* at 12-15.

²⁶⁶ *Id.* at 11-12.

²⁶⁷ Additionally, the actual exhaust temperature is unknown because AGDC has not specified a make or model of compressor turbine to be installed.

²⁶⁸ Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 18.

²⁶⁹ Stamper Report at 12-15,

²⁷⁰ Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 22.

²⁷¹ Email from Andrea Stacy to Dave Jones, "NOx BACT questions for ADEC," (Oct. 26, 2020) ("I am sharing our initial technical evaluation of the AK LNG NOx BACT analysis to aid in the discussion of this topic," And in comparing the Liquefaction plant to the Agrium proposed facility, she explains that "The Agrium Solar turbines are much smaller units than the proposed turbines at the AK LNG liquefaction facility. In general, the "economy of scale" concept indicates that the smaller the unit, the lower the potential emissions reduction and the less cost-effective a measure becomes on a \$/ton basis. While we don't have a cost evaluation for SCR on the Agrium turbines (a cost analysis is not required if a top-level control is selected), it is likely more expensive per ton of NOx removed to control the Agrium turbines than the AK LNG liquefaction facility turbines, calling AGDC's economic feasibility determination into question." (Email and attachment enclosed)

errors in AGDC's BACT analysis, revised the analysis and included the corrected analysis with their communication dated October 26, 2020.²⁷² Therefore, the FLM consultation was occurring *during* the public comment period on this proposed permit and not prior to it as required by the PSD regulations, which is discussed later in our comments.

SCR has been required as BACT for numerous simple cycle and combined cycle turbine, whether used for power generation or as compressor turbines and including turbines at LNG facilities.²⁷³ In fact, ADEC has recently proposed to require SCR to meet NOx BACT at six power generating turbines at the nearby Agrium plant.²⁷⁴ Thus, the cost of installing SCR to meet BACT at the compressor turbines and power turbines of the Liquefaction plant must be considered reasonable to meet BACT. As stated in EPA's Control Cost Manual, "[i]n the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category."²⁷⁵ AGDC has not indicated any unusual circumstances at its compressor turbines and power turbines that would negate SCR from being required to meet BACT, other than the turbines being located in Alaska. That argument is without merit, given other facilities using SCR in Alaska and given that ADEC is proposing to require combustion turbines at the nearby Agrium facility to install SCR to meet NOx BACT.

B. ADEC Fails to Follow the Regulatory Requirements in Proposing BACT for Carbon Monoxide (CO) for the Natural Gas-fired Compressor Turbines and the Power Turbines

As outlined in Ms. Stamper's Report, AGDC's proposed CO BACT limit at both the compressor turbines and at the power turbines reflects the *least* stringent emission limit that has been required as BACT for CO with oxidation catalyst at gas-fired turbines in the EPA's RACT/BACT/LAER Clearinghouse.²⁷⁶ While ADEC proposed a lower CO limit, rather than follow the proper BACT methodology and evaluate the lowest CO limit achievable with catalytic oxidation at gas-fired turbines, ADEC simply took the average of the CO emission limits required for this control at gas turbines and proposed a CO BACT emission based on an average

²⁷² *Id.* ("We found several errors in AGDC's BACT analysis and revised the analysis to correct these errors (attached). We understand that the Department also revised the AGDC analysis to update the bank prime interest rate and the PTE assumptions; however, we found additional assumptions that impact the direct annual costs. It also appears that in their 6th edition estimates, the applicant double counted some TCI fees by including CCM default calculations for line items that were also included in the vendor quote. All revisions to the cost analysis and the basis for our analysis assumptions are documented in the attached spreadsheets along with the "LF_ARD_analysis_assumptions_review_notes.docx" document. Our results indicate that SCR is much more cost-effective for the four power generation turbines and six compressor turbines at the LF facility than what AGDC's analysis suggests.")

²⁷³ Stamper Report at 11-17.

²⁷⁴ See Preliminary ADEC Technical Analysis Report for Construction Permit AQ0083CPT07 issued to Agrium U.S., Inc., for the Kenai Nitrogen Operations, November 20, 2020, Appendix B: Best Available Control Technology (BACT) at 7-8.

²⁷⁵ EPA, New Source Review Workshop Manual, October 1990, at B.29.

²⁷⁶ Stamper Report at 18.

for both the compressor turbines and the power turbines.²⁷⁷ This approach, and the others presented in Ms. Stamper's Report is inconsistent BACT regulation because it is not based on the maximum degree of emission reduction that can be achieved considering the costs of controls and other environmental and energy factors. The goal of the BACT analysis is to be technology-forcing and ensure the maximum degree of emission reduction is achieved, and this is best achieved through the top-down BACT review. ADEC must follow the regulatory process and impose a CO BACT limit reflective of the maximum degree of CO emission reduction achievable at the Liquefaction plant compressor turbines and at the power turbines.

C. BACT for GHG from the Compressor Turbines (Emission Units 1-6) and the Power Turbines (Emission Units 7-10)

ADEC has proposed to find that BACT for GHG emissions from the compressor turbines and the power turbines would be based on good combustion practices and low carbon fuels to meet a GHG limit of 117.1 lb/MMBtu on a 3-hour average basis.²⁷⁸ As discussed in Ms. Stamper's Report, the proposed GHG limit does not reflect the maximum degree of GHG emission reductions that could be achieved at either the compressor turbines or the power turbines.²⁷⁹

1. ADEC's BACT Analysis Improperly Eliminates Carbon Capture and Sequestration

ADEC's analysis considered the information submitted by AGDC on carbon capture and sequestration (CCS) for its combustion turbines. As Ms. Stamper explains in detail, there are several issues with using the information AGDC submitted. First, it fails to include any site-specific costs, and is based on analyses for other facilities.²⁸⁰ Moreover, as Ms. Stamper further notes, ADEC fails to explain what methodology was used to derive the cost estimates for the Liquefaction plant from the other studies.²⁸¹ ADEC's proposal also lacks justification explaining why the information from the other facilities is comparable to the Liquefaction plant. Moreover, the economic analysis and amount of GHG emissions reduced differ in the ADEC and the AGDC analyses. Therefore, the data ADEC relies on is different from what AGDC used. NPCA submitted requests to ADEC for this information, and did not receive it. Therefore, NPCA is unable to review on comment on ADEC's proposal because ADEC has neither provided nor justified the actual cost data it relies on (e.g., capital cost of CCS for the Liquefaction Plant, the transportation costs and assumptions, the operational costs and assumptions, and any other costs). Furthermore, ADEC failed to provide: the details regarding GHG reduction calculations and the cost analysis for CCS at the Golden Pass LNG project that it cites – and relies on – in its Technical Analysis Report.

²⁷⁷ *Id.*

²⁷⁸ ADEC's Preliminary September 11, 2020 TAR, Appendix Bat 19 and at 36.

²⁷⁹ Stamper Report at 19-29.

²⁸⁰ *Id.* at 19-20

²⁸¹ *Id.* at 20-21.

Moreover, given the site-specific considerations of CCS, it is unreasonable for ADEC to first rely on a study for the GTP more than 800 miles away from the proposed Liquefaction plant, and rely on a second study that appears to have been done for a Texas facility. ADEC cannot conclude that CCS is not cost effective for the AK LNG Project without a site-specific evaluation of this highly effective GHG control. Moreover, as Ms. Stamper presents, there are features at the proposed location for the Liquefaction plant that may be a prime area to consider for sequestration of carbon.²⁸² Neither AGDC nor ADEC perform the required study to examine sequestration at the Liquefaction plant site.²⁸³ Thus, ADEC's evaluation of CCS for the Liquefaction plant is wholly deficient because detailed design studies have not been done to assess the feasibility of CCS, and ADEC has no basis to conclude CCS is not cost effective.

2. ADEC's Consideration of the Use of Electric Compressors Fails to Follow the Regulatory Requirements

The EPA has articulated an exception to the BACT requirement known as the "redefinition of the source" doctrine, and under this doctrine, a permitting authority may (but is not required to) eliminate from the BACT analysis an otherwise available control option that would disrupt the basic business purpose of the proposed facility.²⁸⁴ In order to exercise this discretion, the permitting authority must first take a 'hard look' at which design elements are 'inherent' to the applicant's purposes and which design elements could possibly be altered to achieve pollutant reductions while maintaining the facility's basic business purpose. ADEC's incorrectly suggests that consideration of the use of electric compressor would redefine the source.

Another top BACT control option for the compressor turbines is the use electric turbines, which would eliminate all GHG emissions as well as other pollutant emissions from the turbines. Indeed, use of electric compressor turbines is the top level BACT control option for all pollutants. AGDC did identify use of electric motors as a GHG BACT control. However, AGDC eliminated this control from further consideration for the compressor turbines because, as Ms. Stamper's Report explains, AGDC incorrectly asserted that the use of electric turbines would redefine the source given that the Liquefaction plant would not be connected to the local electrical power grid.²⁸⁵ In conducting its analysis, ADEC failed to take a "hard look" at AGDC's business purpose,²⁸⁶ which is of central importance. As Ms. Stamper's report explained, although AGDC did describe that the AK LNG Project was "water dependent" and thus sited the Liquefaction plant to allow for waterborne vessels,²⁸⁷ it did not describe use of

²⁸² Stamper Report at 20-21.

²⁸³ Stamper Report at 19-20.

²⁸⁴ *Helping Hand*, 848 F.3d at 1195; *see also Sierra Club*, 499 F.3d at 654 ("EPA's position is that [BACT] does not include redesigning the plant proposed by the permit applicant" (citing NSR Workshop Manual at B.13).

²⁸⁵ Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 30. Stamper Report at 22.

²⁸⁶ Furthermore, while state permitting agencies are "not necessarily required to follow the analytical framework used by EPA [and the EAB] to assess whether an option may be- excluded from a BACT analysis on 'redefining the-source' grounds," the state agency, if "intend[ing] to employ a different approach," must "articulate its intent to do so and provide a statutory foundation for any alternative approach." *Cash Creek I*, at 9.

²⁸⁷ Stamper Report at 22.

natural-gas burning turbines as one of its business purposes. Additionally, as Ms. Stamper's report explains, ADEC must along consider a mix of electric and natural gas fired turbines.²⁸⁸ AGDC made other faulty assumptions for using electricity from the grid in lieu of the power turbines.²⁸⁹

ADEC, contrary to the BACT regulations requiring consideration of control options, erred in totally excluding the evaluation of using electric compressor engines or electricity from the grid to replace its proposed power turbines in the GHG BACT analysis of its Technical Analysis Review.²⁹⁰ For the reasons detailed in Ms. Stamper's analysis, ADEC should consider electric compressors (if not for all engines (i.e., if grid capacity is limited), then for at least some of the compressor turbines) in lieu of natural gas-fired compressors.²⁹¹ Moreover, to the extent ADEC decides to rely on mere assertions made by AGDC, it must support them with verified, factual information.

3. ADEC's Consideration of Aeroderivative Turbines Fails to Follow the Regulatory Requirements

As discussed in detail in Ms. Stamper's Report, there are several emission reduction benefits of use of aeroderivative turbines compared to heavy duty frame turbines for the compressor turbines at the Liquefaction plant.²⁹² In fact, aeroderivative turbines are being used in other LNG projects including Sabine Pass, Trunkline Project, and Corpus Christi.²⁹³ While AGDC calculated the incremental cost of using aeroderivative turbines in lieu of heavy frame industrial compressor turbines to be \$32/ton of GHG removed.²⁹⁴ ADEC eliminated aeroderivative turbines from consideration in the BACT analysis for both the compressor turbines and power turbines because "it would fundamentally redefine the project...."²⁹⁵ As explained in Ms. Stamper's report, there is no basis for ADEC to claim that use of aeroderivative turbines instead of industrial frame turbines would redefine the project. Aeroderivative turbines are combustion turbines that are more fuel efficient than heavy frame industrial turbines, and they can be operated in both simple cycle mode (such as to drive compressors) and combined cycle mode.²⁹⁶ Further, AGDC has not identified the make and model of turbines that it intends to install. Thus, ADEC is without basis to claim that consideration of a more fuel-efficient

²⁸⁸ *In re N. Mich. Univ. Ripley Heating Plant*, 14 E.A.D. 283, 301–02 (E.A.B. 2009) ("IMU"); *see also Cash Creek I.*

²⁸⁹ Stamper Report at 24.

²⁹⁰ It appears one reason ADEC failed to consider options is that it limited its consideration of control options to unspecified methodology it used to search EPA's RBLC. ADEC has failed to provide details on how it conducted its searching: although NPCA asked for this information, ADEC refused to provide it. Furthermore, the BACT analysis is clearly not limited to a mere review of the RBLC. While that is one place to look, ADEC clearly missed other options by not conducting a broader search.

²⁹¹ Stamper Report at 22-24. ADEC must not automatically dismiss the use of electric turbines as an impermissible redesign, particularly as "the CAA promotes 'clean fuels' with particular vigor. *See* CAA § 169(3), 42 U.S.C. § 7479(3)." *IMU* at 302. Clean fuels may not be "read out" of the Act merely because their use requires "some adjustment" to the proposed technology. *Sierra Club*, 499 F.3d at 656.

²⁹² Stamper Report at 24, 27-28.

²⁹³ *Id.* at 24.

²⁹⁴ As discussed in PreTAR, Appendix B at 18 including Table 3-11.

²⁹⁵ PreTAR, Appendix B at 17 and 34.

²⁹⁶ Stamper Report at 24-5 and 27.

turbine in an analysis of BACT for greenhouse gas emissions would be a redefinition of the project.

Furthermore, AGDC's incremental cost analysis of aeroderivative compressor turbines, the use of aeroderivative gas turbines appears to be very cost effective at \$32/ton. However, AGDC did not provide the assumptions that went into this Yet – as Ms. Stamper explains AGDC claimed aeroderivative turbines would only be cost effective if turbine fuel costs were \$7.50 per million British Thermal Units (MMBtu) or greater.²⁹⁷ Although AGDC did not provide the background data that went into this incremental cost analysis or explain its finding, it appears that AGDC's criteria of consideration of aeroderivative turbines to meet BACT for GHG was whether the costs of the aeroderivative turbines would be close to the same as the industrial turbines. Ms. Stamper's report explains that AGDC failed to answer the fundamental question posed by the cost effective analysis; which is whether it is cost effective to use aeroderivative turbines, which would emit less GHG emissions for the same amount of power generation. Indeed, AGDC's own analysis admits that "other comparable LNG projects have incorporated [aeroderivative turbines] into their design" including Sabine Pass, Trunkline Project, and Corpus Christi,²⁹⁸ which shows that other similar sources have used these turbines to reduce GHG emissions.

Ms. Stamper's report further explains the challenges the public faced in reviewing this proposed action. Although AGDC conducted what it characterized as a "cost effectiveness analysis," the information ADEC made available at the start of the public comment period failed to include any of the details regarding AGDC's cost effectiveness analysis. AGDC's increment cost spreadsheet was made available to the public at the request of National Parks and Conservation Association, after ADEC negotiated with AGDC to have them withdraw its wrongfully asserted Confidential Business Information (CBI) claims.²⁹⁹ Based on Ms. Stamper's review and analysis, AGDC's analysis contained numerous errors (e.g., taking into account capital costs to replace the planned 6 compressor turbines with 12 smaller capacity aeroderivative turbines when aeroderivative turbines of the same size as the planned compressor turbines are available, more than doubling the interest rate in amortizing capital costs, and overstating maintenance costs).³⁰⁰ Moreover, AGDC assumed a higher heat rate for the aeroderivative turbines than is justified, which had the effect of underestimating the amount of GHG reductions from use of aeroderivative turbines and overstating the amount of fuel necessary for the aeroderivative turbines.³⁰¹

As seen in Ms. Stamper's report, by correcting these assumptions, she found the incremental cost effectiveness of use of aeroderivative turbines reduces to \$29/ton.³⁰² For this analysis, Ms. Stamper assumed the cost for natural gas was \$2.57/MMBtu based on the Henry Hub Natural Gas Spot Price for January to December of 2019 as the cost for natural gas.³⁰³ Thus, as she explains, use of aeroderivative turbines could be a cost effective GHG control, and

²⁹⁷ *Id.* at 25.

²⁹⁸ Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 29.

²⁹⁹ See spreadsheet entitled "23_Trade Secret_cost effectiveness_Compression Turbines" at row 24 of tab entitled "GHG-Incremental" that was included in the "2018.05.01 Original Submittal" provided to NPCA by ADEC in November of 2020.

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³⁰⁰ Stamper Report at 25-27.

³⁰¹ Stamper Report at 26-27.

³⁰² *Id.* at 26.

³⁰³ *Id.*

use of such turbines would avoid approximately 410,000 tons per year of GHG emissions simply by using more energy efficient turbines for the compressor turbines.³⁰⁴ In addition to the decreased GHG emissions, turbines that use less natural gas will also emit lower levels of all other air pollutants on an hourly and annual basis.³⁰⁵

Furthermore, AGDC's BACT analysis did not discuss use of aeroderivative turbines at all for the power turbines, but it should have. Along with reduced GHG emissions, there are several other benefits that could be realized with the use of aeroderivative gas turbines, such as improved ability to reduce NOx with SCR, shorter startups, less frequent and lower downtime for maintenance which will reduce flaring emissions, and lower emissions of all air pollutants due to burning less fuel for the same level of power produced.³⁰⁶ Thus, this GHG control technique of using aeroderivative turbines must be given more weight in ADEC's GHG BACT analysis as it appears to be a very cost effective method of reducing GHG emissions with several other air quality benefits.

4. ADEC Has Not Justified that the GHG Limit it Proposes is BACT

Contrary to the requirements in Alaska's SIP, ADEC fails to evaluate and document GHG BACT for the compressor turbine and the power turbines. For example, ADEC fails to provide a technical basis for its proposed GHG BACT limit for the compressor turbines and power turbines, it merely suggests the limit is based on good combustion practices and burning clean fuels.³⁰⁷ Furthermore, in setting this limit, ADEC cannot rely on AGDC's information for the CO2 emissions rate per megawatt-hour for its compressor turbines, because AGDC did not provide nor does the permit specify the turbine make or model.³⁰⁸ As Ms. Stamper identifies in her report, "A review of the draft permit shows that ADEC has imposed the same 117.1 lb/MMBtu GHG BACT limit for every emission unit at the proposed Liquefaction plant – that is, the compressor turbines, the combined cycle emission units, and the flares."³⁰⁹ These are not case-specific BACT determinations, rather ADEC's proposed limits are "simply the EPA GHG emission factor for natural gas combustion at any type of combustion source."³¹⁰ Contrary to the requirements, ADEC's limit does not:

- Reflect the maximum degree of GHG emission reduction achievable for the source considering costs of control and other impacts; and
- Encourage improvements in efficiency or even good combustion practices.

³⁰⁴ *Id.* at 28.

³⁰⁵ *Id.*

³⁰⁶ *Id.* at 27-28.

³⁰⁷ Stamper Report at 28-29. Additionally, as Ms. Stamper explains, AGDC's submittal similarly lacks the required BACT evaluation as AGDC did not identify any claimed heat rate for those turbines and simply proposed using a combined cycle turbine, low carbon fuel, and energy efficiency as BACT for GHG emissions. Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 44.

³⁰⁸ *Id.*

³⁰⁹ Stamper Report at 29.

³¹⁰ *Id.* See EPA GHG Emission Factors, available at <https://www.epa.gov/sites/production/files/2020-04/documents/ghg-emission-factors-hub.pdf>. The emission factors for CO₂, methane (CH₄) and nitrous oxide (N₂O) convert to 117.1 lb/MMBtu (after applying the global warming potential factors in 40 C.F.R. Part 98, Table A-1.

Moreover, as explained in Ms. Stamper's report, ADEC's GHG BACT determination for the power turbine was based on "maintaining good combustion practices and burning clean fuels at all times"³¹¹ and nothing in the permit requires that the power turbines be operated in combined cycle mode nor does the permit limit the time such units can operate in the less efficient simple cycle mode.³¹² This is an issue because operating in a combined cycle mode is a GHG BACT control, and at the very minimum, ADEC's GHG BACT limit for the power turbines must be based on the combined cycle operation of the units.³¹³

Furthermore, ADEC's proposal is inconsistent with EPA's GHG permitting guidance, which, states that: GHG BACT limits should at the minimum encourage energy efficiency by being output-based limits (as in lb/MW-hr or lb/horsepower-hour); and other requirements may also be imposed to ensure energy efficiency, such as an environmental management system focused on energy efficiency.³¹⁴ The proposed BACT limits do not provide for energy efficiency and require any level of GHG control other than burning natural gas.

In sum, as highlighted in these comments and discussed in more detail in Ms. Stamper's Report, there are several options that ADEC should considered in adopting a BACT emission limit for GHG, including carbon capture and sequestration, use of electric compressors, use of aeroderivative turbines, and operating in combined cycle mode. Between its lack of a full evaluation of GHG control options and the lack of documentation in the record to support its proposed emission limit, the GHG BACT determinations for the compressor turbine and the power turbines are wholly inadequate and must be redone.

D. ADEC Must Not Exempt Startup and Shutdown from BACT Emission Limits

BACT is an "emission limitation," and an "emission limitation" is defined as a requirement that limits the rate of emissions "on a continuous basis."³¹⁵ As detailed in Ms. Stamper's report,³¹⁶ ADEC's exemptions for the compressor and power turbines from complying with BACT limits during startup and shutdown are inconsistent with the definition of BACT and must be removed.

Additionally, Ms. Stamper's report documents numerous concerns about the enforceability of the proposed permit regarding startup and shutdown situations:

³¹¹ ADEC's Preliminary September 11, 2020 TAR, Appendix B at 36.

³¹² Draft Permit at 1, Table 1. Notably, the Draft Permit states that the "information in Table 1 is for identification purposes only" and that "[t]he specific [emission unit (EU)] descriptions do not restrict the Permittee from replacing an EU identified in Table 1." *Id.*

³¹³ Stamper Report at 29.

³¹⁴ *Id.*, citing EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011, at 46.

³¹⁵ 18 AAC 50.990(30)(definition of "emission limitation" has the meaning given in AS 46.14.990. AS 46.14.990(10) defines "emission limitation" and "emission standard" as in 40 C.F.R. § 51.100(z)("Emission limitation and emission standard mean a requirement established by a State, local government, or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirements which limit the level of opacity, prescribe equipment, set fuel specifications, or prescribe operation or maintenance procedures for a source to assure continuous emission reduction.")

³¹⁶ Stamper Report at 30-31.

- ADEC’s proposed work practice standards for the power turbines are vague and provide significant flexibility to AGDC without providing assurance that emissions will be minimized during these periods;³¹⁷
- It does not require any recordkeeping or reporting on the frequency, magnitude, and duration of exceedances of BACT emission limits during startup, shutdown, or malfunction;
- It does not require any documentation that manufacturer’s specifications and good combustion practices were followed during such periods.³¹⁸

Further, as demonstrated in other states – and presented in Ms. Stamper’s report – it is feasible to impose alternative emission limits that apply during periods of startup and shutdown.³¹⁹ If ADEC justifies the need for alternative BACT limits during startup and shutdown at the compressor turbines and the power turbines, such alternative limits should apply only to BACT limits for NO_x, CO and VOC emissions. Table 4 of Ms. Stamper’s report provides examples from other permitting authorities.³²⁰ For SO₂, PM₁₀ and PM_{2.5} emissions, no exemption from BACT requirements should be authorized at all. BACT for PM (PM₁₀ and PM_{2.5}) and SO₂ at natural gas-fired combined cycle power plants is based on burning pipeline quality natural gas with low sulfur content, and the effectiveness of that pollution control does not vary during periods of startup and shutdown.³²¹

Since BACT is to be met during all periods of operation, ADEC must revise the draft permit terms and conditions for the compressor turbines and the power turbines to ensure that the maximum degree of emissions reduction is required on a continuous basis.

E. ADEC’s BACT for the Diesel-Fired Engines (EU 11 and 12) is Unlawful

The Liquefaction plant will have two diesel-fired engines- a 575 horsepower diesel fire pump (EU 11) and a 300 horsepower diesel-fired auxiliary air compressor engines (EG 12). The Draft Permit limits operations of these engines to 500 hours per year each.³²² These engines are of a source category regulated under the EPA’s New Source Performance Standards (NSPS) at 40 C.F.R. Part 60, Subpart IIII (Standards of Performance for Stationary Internal Combustion Engines). Therefore, as discussed in detail earlier in our comments, BACT can be no less stringent than the applicable NSPS standards. As presented in detail in Ms. Stamper’s Report, ADEC has proposed BACT limits for these engines that are less stringent than the NSPS BACT floor.³²³

³¹⁷ ADEC simply requires that AGDC operate the turbines “according to manufacturer’s specifications and good combustion practices.” Draft Permit at 13 and 17.

³¹⁸ Stamper Report at 30.

³¹⁹ *Id.* at 14 (Table 4) and 30.

³²⁰ *Id.* at 14 and 30-31.

³²¹ *Id.* at 30-31.

³²² Draft Permit at 12.

³²³ Stamper Report at 31-33.

Given that BACT is supposed to be based on the maximum degree of emission reduction achievable and the fact that this is a new Liquefaction plant, ADEC should require that both diesel engines meet Tier 4 emission standards as BACT limits.³²⁴ Tier 4 engines are readily available and, given that Tier 4 engines achieve the lowest emission rates of NOx, PM and CO, such engines should be considered BACT for the firewater pump (EU 12) as well as for the auxiliary air compressor (EU 11).³²⁵

F. ADEC's BACT for the Flares is Unlawful

The Liquefaction plant will have 7 flares: a dry ground flare and wet ground flare (maximum capacities of 55,000 million standard cubic feet per hour (Mscf/hr) and of 13,000 Mscf/hr) for each of the three LNG lines (EU's 14-19), and an elevated low pressure flare with maximum relief capacity of 990 Mscf/hr (EU 20).³²⁶

While ADEC conducted a BACT analysis for the various pollutants to be emitted by the flares, the emission limits it has proposed are, with the exception of SO₂, simply reflective of EPA emission factors for flares.³²⁷ While ADEC's draft permit will limit the number of hours each flare can operate to not more than 500 hours per consecutive 12 months, the limit applies only to flaring during startup, shutdown, and maintenance events and does not include upsets or emergency flaring, which can be a significant cause of prolonged flaring.³²⁸ The Draft Permit also imposes a GHG emission limit of 117.1 lb/MMBtu³²⁹ which, as stated above, is simply the same as the EPA GHG emission factor for GHG emissions from natural gas combustion (i.e., it does not require any reduction in GHG emissions). Further, although ADEC has proposed emission limits in terms of lb/MMBtu for NOx, CO, PM, VOCs, and GHG, there are no requirements to ensure that these emission limits are met, other than training of flare operators and meeting the work practice standards of 40 C.F.R. §§ 60.18(c) through (f).³³⁰ Ms. Stamper's Report continues additional important information on flare operations.³³¹

1. ADEC Failed to Evaluate Capture and Use of the Excess Natural Gas Stream in Lieu of Flaring the Excess Natural Gas Stream

ADEC improperly ignored other techniques in lieu of flaring, including the top BACT option: eliminate flaring by capturing the excess gas for use, rather than to flare the excess gas. Ms. Stamper's report presents several options to capture and use of the excess gas.³³² ADEC should evaluate this option as a BACT control for all pollutants emitted by flaring.

2. ADEC Failed to Evaluate the Control Option of Use of a Thermal Incinerator in Lieu of Flares

³²⁴ Stamper Report at 33.

³²⁵ *Id.*

³²⁶ Draft Permit at 1 (Table 1).

³²⁷ ADEC's Preliminary September 11, 2020 TAR, Appendix B at 64, 66, 67, 71, and 73. Stamper Report at 34.

³²⁸ Draft Permit at 23 (Condition 17).

³²⁹ *Id.*

³³⁰ *Id.* at 24.

³³¹ Stamper Report at 33-35.

³³² Stamper Report at 35.

Another control option that ADEC should evaluate is requiring excess natural gas to be combusted in a thermal incinerator, rather than through flaring, in which the combustion of the natural gas could be controlled to a much greater extent than in an open flame of an elevated flare. As explained in Ms. Stamper's report, use of thermal incinerators instead of flaring could provide for greater control of VOCs through the ability to control and optimize the combustion of the gas, and low NOx burners are available which could decrease NOx emissions as compared to flaring of the natural gas.³³³

For these and other reasons discussed in Ms. Stamper's Report, ADEC erred in not evaluating the use of a thermal incinerator as a BACT option in lieu of flaring.

3. ADEC's Proposed Permit Requirements for Minimization of Flaring Are Inadequate to Reflect BACT

As Ms. Stamper explains, minimization of flaring is another important BACT option to fully evaluate. ADEC stated that it based its BACT determination on establishing a flare minimization plan, and the permit requires that AGDC develop and keep on-site a flare minimization plan.³³⁴ However, the provisions of the Draft Permit regarding the flare minimization plan do not reflect enforceable requirements, because the Draft Permit simply leaves it up to the company to develop a flare minimization plan without requiring that plan to be submitted to and reviewed by ADEC and/or become part of the permit. In addition, as the LNG plant ages, the approaches to minimizing flaring may change over time. Thorough recordkeeping and reporting of flaring incidents from all causes (startup, shutdown, maintenance, as well as upsets) is imperative for ensuring that flaring is minimized. Recordkeeping and reporting allows for lessons to be learned from flaring events and for appropriate flaring minimizing plans to be put into place from excess flaring events.³³⁵ Ms. Stamper's report lists the factors EPA has listed to prevent excess flaring at refineries, and this same approach can be used to identify methods and techniques to reduce flaring at LNG facilities, along with other EPA recommendations to reduce the amount of flaring due to upsets.³³⁶

Finally, Ms. Stamper's Report discusses in detail numerous additional provisions that ADEC must include to ensure the flares are maintained and operated properly and that use of flares is minimized. Importantly, a limit on total hours of flaring due to all causes including upsets would provide significant incentive for AGDC to truly minimize flaring of excess gas.

ADEC must analyze all of these BACT options for flaring, including capture and use of excess gas to eliminate or greatly minimize flaring and use of a thermal incinerator in lieu of flaring for more complete combustion and better control of VOCs and NOx. If ADEC determines flare minimization is the top BACT control option, it must include additional requirements in the permit to ensure that flaring is truly minimized.

³³³ *Id.* at 35-36.

³³⁴ Draft Permit at 24.

³³⁵ Stamper Report at 37.

³³⁶ *Id.*

VI. The Draft Permit Unlawfully Relies on Deficient and Inaccurate Air Quality Modeling

An air quality analysis provides predictions of pollutant concentrations in ambient air by modeling the impacts of new emissions from a proposed source. Congress' concern about modeling science led it to require EPA to establish uniform modeling techniques for use in PSD permitting. EPA is expected to develop and utilize the most accurate and feasible modeling techniques available, and to review and update those models periodically as modeling science develops.³³⁷ EPA did develop modeling guidelines, 40 C.F.R. § 52.21(1), and they were subsequently upheld on judicial review.³³⁸ PSD permit applicants use modeling to demonstrate compliance with the requirements for obtaining a permit.³³⁹ The main purpose of the air quality impacts analysis is to demonstrate that the new emissions emitted from a proposed major stationary source, in conjunction with other applicable emissions from existing sources, will not cause or contribute to a violation of any applicable NAAQS or PSD increment.³⁴⁰ The NAAQS are maximum concentration 'ceilings' measured in terms of the total concentration of a pollutant in the atmosphere for certain pollutants that apply nationwide. The standards are set at levels that the Administrator of EPA has determined are necessary to protect the public health and welfare. PSD increments are maximum allowable increases in pollutant concentration over baseline concentrations. The permit applicant's analysis must calculate whether the proposed emissions will be within the applicable PSD increment. The PSD increment concept was designed to accommodate economic growth and increased pollution associated with such growth while placing limits on new pollution. Significant deterioration is prevented if the amount of new pollution from the proposed source, in conjunction with pollution from certain existing sources, is less than the amount permitted by the PSD increment.³⁴¹ Permit applicants must use EPA-approved models.³⁴² Written approval from EPA's Administrator is required for model substitutions and modification, as well as public notice and opportunity for comment.³⁴³ If, after taking into account emissions from a proposed source and emissions from certain existing sources, the modeled ambient air concentration of a pollutant is below the NAAQS, and the

³³⁷ See 42 U.S.C. §§ 7475(e)(3)(D) and 7620.

³³⁸ *Alabama Power*.

³³⁹ See, e.g., *Hadson Power*.

³⁴⁰ 18 AAC 50.040(h)(9), incorporating by reference 40 C.F.R. § 52.21(k) (Source Impact Analysis) ("The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:

(1) Any national ambient air quality standard in any air quality control region; or
(2) Any applicable maximum allowable increase over the baseline concentration in any area.")

³⁴¹ See NSR Workshop Manual at C.3.

³⁴² 18 AAC 50.040(h)(10), incorporating by reference 40 C.F.R. § 52.21(l)(1) ("All estimates of ambient concentrations required under this paragraph shall be based on applicable air quality models, data bases, and other requirements specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models).")

³⁴³ 18 AAC 50.040(h)(10), incorporating by reference 40 C.F.R. § 52.21(l)(2) ("Where an air quality model specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models) is inappropriate, the model may be modified or another model substituted. Such a modification or substitution of a model may be made on a case-by-case basis or, where appropriate, on a generic basis for a specific state program. Written approval of the Administrator must be obtained for any modification or substitution. In addition, use of a modified or substituted model must be subject to notice and opportunity for public comment under procedures developed in accordance with paragraph (q) of this section."). See also *In re AES Puerto Rico L.P.*, 8 E.A.D. 324, 337 (EAB 1999).

increase in concentration for that pollutant is less than the applicable PSD increment, the permit applicant has successfully demonstrated compliance.³⁴⁴

The models are listed in the “Guideline on Air Quality Models” 40 C.F.R. part 51, appendix W.³⁴⁵ ADEC adopts EPA’s Guideline on Air Quality Models by reference, which was most recently approved by EPA on August 29, 2019 to include the following: 18 AAC 50.040(f) (“The provisions of 40 C.F.R. Part 51, Appendix W (Guideline on Air Quality Models), revised as of July 1, 2017, are adopted by reference.”) EPA’s 2019 approval also included 18 AAC 50.215 Ambient Air Quality Analysis Methods.

As discussed in Mr. Gebhart’s Report, ADEC’s “lack of scientific certitude about modeling techniques”³⁴⁶ relied on and developed for the proposed PSD permit, demonstrates the need for the agency to develop new accurate information that meets the regulatory requirements and renounce the proposed permit to provide for public comment.

A. ADEC Inappropriately Relies on the Modeling Analysis Prepared for NEPA Compliance

As explained in Mr. Gebhart’s Report, “the PSD permit modeling for the most part relied upon air quality modeling completed by the applicant for the EIS,” which “was seriously flawed and these flaws were therefore carried forward into the PSD permit modeling.”³⁴⁷ For example the:³⁴⁸

- EIS indicated that the technical information about the Project used for the air quality modeling assessment was outdated and/or incorrect;
- Construction-related emissions were inconsistent with the applicant’s current project schedule and as such were outdated;
- CALPUFF modeling addressing Class I area impacts was incomplete because cumulative impacts were not properly addressed; and
- Maritime emissions were not calculated based on the maximum number of vessels serving the Liquefaction plant.

ADEC’s PreTAR explained that:

AGDC conducted various air quality demonstrations under the National Environmental Policy Act (NEPA) prior to submitting their permit application for the Liquefaction plant. They therefore relied on these previous demonstrations, to the extent possible, for the ambient analyses required under PSD. This type of coordinated approach is encouraged by

³⁴⁴ NSR Workshop Manual at C.51. *See also In re Knauf I* at 149.

³⁴⁵ *See* 40 C.F.R. § 52.21(l)(1)(“ (1) All estimates of ambient concentrations required under this paragraph shall be based on applicable air quality models, data bases, and other requirements specified in appendix W of part 51 of this chapter (Guideline on Air Quality Models).”) (“Guideline on Air Quality Model”)

³⁴⁶ *Alabama Power* at 388.

³⁴⁷ Gebhart Report at 1.

³⁴⁸ *Id.* at 2. Additional issues related to ADEC’s reliance on the EIS air quality impact modeling are presented in these comments.

EPA under 40 CFR 52.21(s). The Department has not adopted this citation by reference (since it has no control over the federal actions conducted under NEPA), but the Department nevertheless agrees that the analyses should be consistent where possible.³⁴⁹

As ADEC notes, 40 C.F.R. § 52.21(s) does not apply to the State. Furthermore, that particular regulation clearly states that while coordination between the Clean Air Act and NEPA is aspirational, it shall only be done to the “extent feasible *and reasonable*.”³⁵⁰

Therefore, ADEC’s proposed PSD permit analysis is also incomplete, inaccurate, and furthermore, does not provide for a complete understanding and analysis of air quality impacts as is required under federal and State of Alaska PSD permit regulations.³⁵¹ “ADEC’s reliance on the EIS modeling, which was completed to fulfill a separate legal requirement, was inappropriate and in turn led to substantial and significant errors in the assessment of the real-world air quality impacts.”³⁵² As discussed throughout these comments, it was unreasonable for ADEC to rely on information compiled in the NEPA context where the information fails to meet Clean Air Act requirements.

B. ADEC Failed to Consider the Range of Operations in the Modeling Scenarios

EPA’s Guideline on Air Quality Models requires that

For point sources, there are many source characteristics and operating conditions that may be needed to appropriately model the facility. For example, the plant layout (e.g., location of stacks and buildings), stack parameters (e.g., height and diameter), boiler size and type, potential operating conditions, and pollution control equipment parameters. Such details are required inputs to air quality models and are needed to determine maximum potential impacts.³⁵³

For stationary source applications, changes in operating conditions that affect the physical emission parameters (e.g., release height, initial plume volume, and exit velocity) shall be considered to ensure that maximum potential impacts are appropriately determined in the assessment. For example, the load or operating condition for point sources that causes maximum ground-level concentrations shall be established. As a minimum, the source should be modeled using the design capacity (100 percent load). If a source operates at greater than design capacity for periods that could result in violations of the NAAQS or PSD increments, this load should be modeled. Where the source operates at substantially less than design capacity, and the changes in the stack parameters associated with the operating conditions could lead to higher ground level

³⁴⁹ PreTAR at 3.

³⁵⁰ 40 C.F.R. § 52.21(s)(“*Environmental impact statements*. Whenever any proposed source or modification is subject to action by a Federal Agency which might necessitate preparation of an environmental impact statement pursuant to the National Environmental Policy Act (42 U.S.C. 4321), review by the Administrator conducted pursuant to this section shall be coordinated with the broad environmental reviews under that Act and under section 309 of the Clean Air Act to the maximum extent feasible *and reasonable*.”) (emphasis added)

³⁵¹ Gebhart Report at 1.

³⁵² *Id.* at 3.

³⁵³ Guideline on Air Quality Model, ¶ 8.2.1 (b)

concentrations, loads such as 50 percent and 75 percent of capacity should also be modeled. Malfunctions which may result in excess emissions are not considered to be a normal operating condition. They generally should not be considered in determining allowable emissions. However, if the excess emissions are the result of poor maintenance, careless operation, or other preventable conditions, it may be necessary to consider them in determining source impact. A range of operating conditions should be considered in screening analyses. The load causing the highest concentration, in addition to the design load, should be included in refined modeling.³⁵⁴

In modeling emission scenarios, it was unreasonable for ADEC not to consider different flaring operations. The dispersion modeling for the Liquefaction plant *only* addressed “normal operations,” which was represented as full build-out of the liquefaction processing equipment at the maximum production rate.³⁵⁵ However, Resource Report No. 9 Appendix D states that “considerable flaring over six (6) months” will occur during Liquefaction plant commissioning and start-up,³⁵⁶ which was not addressed in the PSD permit modeling evaluation. Mr. Gebhart’s Report explains that because flaring will have different air dispersion characteristics and would produce air quality impacts that might vary significantly from those modeled under “normal operations,” one cannot rely solely on emissions comparisons when deciding if and when to model possible flaring scenarios.³⁵⁷ Therefore, “[a]ppropriate flaring scenarios need to be independently considered; otherwise, the Liquefaction plant air dispersion modeling analysis as presented by the ADEC TAR is incomplete.”³⁵⁸

Furthermore, “[u]nder the EPA Guideline on Air Quality Models (40 CFR 51, Appendix W), modeling of combustion sources at partial load is recommended because the plume rise will be less during partial load conditions, which can lead to elevated ground-level pollutant impacts even when emissions are less.”³⁵⁹ “Also, for the Liquefaction plant combustion turbines, only 100% load was considered in the air quality modeling impact analysis,” and “[i]t was not realistic for ADEC to assume that the Liquefaction plant combustion sources would only operate at or near full capacity.”³⁶⁰ Instead, “[t]he air quality modeling needed to address the possibility of operating the combustion turbines and other combustion sources at less than 100% load. In the absence of such modeling, the PSD permit should have imposed appropriate operational restrictions to prohibit operating the turbines and other combustion sources at less than 100% load.”³⁶¹

³⁵⁴ Guideline on Air Quality Model, ¶ 8.2.2 (d)

³⁵⁵ *Id.* at 3.

³⁵⁶ Alaska LNG Project, “RESOURCE REPORT NO. 9 APPENDIX D – LIQUEFACTION FACILITY AIR QUALITY MODELING REPORT,” at 9 (April 14, 2017), available at http://alaska-lng.com/wp-content/uploads/2017/04/Alaska-LNG-RR9-AppxD_041417_Public.pdf

³⁵⁷ Gebhart Report at 2.

³⁵⁸ *Id.*

³⁵⁹ Guideline on Air Quality Model, ¶ 8.2.2 (d)

³⁶⁰ Gebhart Report at 3.

³⁶¹ 18 AAC 50.040(h)(9), incorporating by reference 40 C.F.R. § 52.21(k), *see also* NSR Workshop Manual at C.24-25.

C. ADEC Ignores Onsite Meteorological Data, Fails to Demonstrate Data Used is Representative and Processes Data Inconsistently with Regulatory Requirements

In order to perform an air quality analysis, certain data must be obtained, including information on existing ambient air quality, emission rates from the proposed source, and meteorological data to predict how emissions will behave once they are emitted from the proposed source. Ambient background concentrations are essential in constructing the design concentration, or total air quality concentration, as part of a cumulative impact analysis for NAAQS and PSD increments.³⁶² Background air quality should not include the ambient impacts of the project source under consideration. Instead:³⁶³

- The monitoring network used for developing background concentrations is expected to conform to the same quality assurance and other requirements as those networks established for PSD purposes. Accordingly, the air quality monitoring data should be of sufficient completeness and follow appropriate data validation procedures. These data should be adequately representative of the area to inform calculation of the design concentration for comparison to the applicable NAAQS (section 9.2.2).³⁶⁴
- The EPA recommends use of the most recent quality assured air quality monitoring data collected in the vicinity of the source to determine the background concentration for the averaging times of concern. In most cases, the EPA recommends using data from the monitor closest to and upwind of the project area. If several monitors are available, preference should be given to the monitor with characteristics that are most similar to the project area. If there are no monitors located in the vicinity of the new or modifying source, a “regional site” may be used to determine background concentrations. A regional site is one that is located away from the area of interest but is impacted by similar or adequately representative sources.³⁶⁵

The liquefaction modeling analysis relied on five years of meteorological data from Kenai Airport (2008-12), yet it appears that on-site meteorological monitoring data was also collected at or near the Liquefaction plant.³⁶⁶ EPA’s Modeling Guideline, which is in Alaska’s SIP “indicates a preference for on-site data when such data are available.”³⁶⁷ Therefore, “[t]he applicant should have used the on-site meteorological monitoring data for the air quality

³⁶² Guideline on Air Quality Model, 9.2.3. The PSD requirements for the ambient air quality data are in 40 C.F.R. § 52.21(m)(1)(iv), which similarly require that the data is representative. 18 AAC 50.040(h)(11), incorporating by reference 40 C.F.R. § 52.21(m)(1)(iv).

³⁶³ *Id.*, at 8.3.1(a).

³⁶⁴ *Id.*, at 8.3.1(b).

³⁶⁵ *Id.*, at 8.3.2(b).

³⁶⁶ ADEC Draft Technical Analysis Report, Section 5.3, *See also* Resource Report #9.

³⁶⁷ Guideline on Air Quality Model, ¶ 8.4.4.1 (“Site-specific measured data are therefore preferred as model input provided that appropriate instrumentation and quality assurance procedures are followed, and that data collected are adequately representative”).

modeling calculations or explained why the Kenai Airport data were more appropriate for the Liquefaction plant air quality analysis.”³⁶⁸

In any case, any meteorological data used as input to air quality models supporting a PSD permit application need to be “representative” of the transport and dispersion conditions in the project area. Specifically, Appendix W carries the following language regarding the need for representative meteorological data:

The meteorological data used as input to a dispersion model should be selected on the basis of spatial and climatological (temporal) representativeness as well as the ability of individual parameters to characterize the transport and dispersion conditions in the area of concern.³⁶⁹

However, the ADEC TAR and other information in the record are silent as to whether the Kenai Airport data are “representative.” Until the Kenai Airport data are evaluated and shown to meet the “representative data” criterion in Appendix W and the regulation, they cannot be used to support a PSD permit application.

Lastly, the TAR notes that the applicant’s modeling of air quality impacts “randomized” the wind directions when processing the Kenai Airport meteorological data. This is contrary to USEPA guidelines when meteorological data are processed with the AERMINUTE data processor, which occurred in this case. The applicable EPA guidelines on this issue were well established and date to 2013,³⁷⁰ long before the applicant filed the modeling protocol and completed the Liquefaction plant air modeling for the PSD permit. ADEC should have invalidated the applicant’s modeling and instead required that the meteorological data processing conform with EPA and ADEC guidelines (please refer to additional comments later in Mr. Gebhart’s Report that address ADEC’s so-called sensitivity analyses, which is how ADEC tried to address this issue and other inconsistencies between the applicant’s modeling and applicable modeling guidelines).

D. ADEC Relies on Baseline Air Quality Data that is Not Representative of Baseline Conditions

As Mr. Gebhart’s Report explains, “[a]ll PSD applicants need to collect ambient air quality measurements documenting baseline conditions representative of the current air quality at

³⁶⁸ Gebhart Report at 3. Moreover, an applicant cannot substitute ambient data unless it is deemed “sufficiently representative of air quality in the targeted area — in terms of the sufficiency of the monitoring locales selected and the quality and currentness of the monitoring data — to legitimately be substituted for site-specific data.” *NMU* at 325, *citing* NSR Workshop Manual at C.18-19; *Ambient Monitoring Guidelines* § 2.4, at 6-9; *see also, e.g., Knauf I* at 145-48; *In re Haw. Elec. Light Co.*, 8 E.A.D. 66, 97-105 (EAB 1998); *In re Hibbing Taconite Co.*, 2 E.A.D. 838, 850-51 (EAB 1989).

³⁶⁹ Guideline on Air Quality Model, ¶ 8.4.1(b).

³⁷⁰ U.S. Environmental Protection Agency, 2013. Use of ASOS meteorological data in AERMOD dispersion modeling. Memorandum dated March 8, 2013, Office of Air Quality Planning and Standards, Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/guidance/clarification/20130308_Met_Data_Clarification.pdf. (cited at n95 in the Guideline on Air Quality Model)

the project site, or otherwise demonstrate that it meets the applicable monitoring exemptions under the applicable PSD regulations. In part, the applicant met this requirement by collecting on-site measurements for nitrogen oxides (NO_x), sulfur dioxide (SO₂), and carbon monoxide (CO), which operated from September 2018 through August 2019.”³⁷¹

“However, for the PM-10, PM-2.5, and ozone (O₃) baseline monitoring, the applicant relied upon data collected during 2013-14 to support a previous PSD permit action by a nearby facility (Agrium). These data cannot be used to support a PSD permit action in 2020 as the 2013-14 data no longer accurately represent the current baseline air quality conditions around the Liquefaction plant site. Even at the time that the PSD permit application was filed by the applicant (May 1, 2018), these data were approaching five years old. The applicant has not complied with the PSD baseline monitoring requirements because the applicant has relied upon data which is out of date and no longer representative of baseline air quality conditions.”³⁷²

E. ADEC’s Methodology is Inconsistent with the Regulatory Requirements for NO_x Emissions Modeling

The Liquefaction plant modeling applied the Ambient Ratio Method (ARM2) to address the atmospheric conversion of NO_x emissions to nitrogen dioxide (NO₂), which is the regulated form for NO_x under the National Ambient Air Quality Standards (NAAQS). ARM2 is the recommended Tier 2 modeling approach under the Guideline.³⁷³ The Modeling Guideline recommends 0.5 for the lower limit in the ARM2 calculations. However, the Liquefaction plant NO_x modeling used the Tier 2 Ambient Ratio Method (ARM2) lower limit as 0.2, which does not conform to the Modeling Guideline.^{374, 375} While prior versions of Appendix W may have listed lower thresholds for this variable, the current version in ADEC’s SIP is the 2017 Guideline, which EPA adopted nearly four years ago.³⁷⁶ Therefore, the Liquefaction plant

³⁷¹ Gebhart Report at 4. See 18 AAC 50.040(h)(11), incorporating by reference 40 C.F.R. § 52.21(m)(b)(iv)(“In general, the continuous air quality monitoring data that is required shall have been gathered over a period of at least one year and shall represent at least the year preceding receipt of the application, except that, if the Administrator determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that is required shall have been gathered over at least that shorter period.”)

³⁷² Gebhart Report at 4.

³⁷³ Guideline on Air Quality Model, ¶ 4.2.3.4.d).

³⁷⁴ Gebhart Report at 4.

³⁷⁵ Guideline on Air Quality Model 4.2.3.4 Models for Nitrogen Dioxide (“d. For Tier 2, multiply the Tier 1 result(s) by the Ambient Ratio Method 2 (ARM2), which provides estimates of representative equilibrium ratios of NO₂/NO_x value based ambient levels of NO₂ and NO_x derived from national data from the EPA’s Air Quality System (AQS).⁵⁵ The national default for ARM2 includes a minimum ambient NO₂/NO_x ratio of 0.5 and a maximum ambient ratio of 0.9. The reviewing agency may establish alternative minimum ambient NO₂/NO_x values based on the source’s in-stack emissions ratios, with alternative minimum ambient ratios reflecting the source’s in-stack NO₂/NO_x ratios. Preferably, alternative minimum ambient NO₂/NO_x ratios should be based on source-specific data which satisfies all quality assurance procedures that ensure data accuracy for both NO₂ and NO_x within the typical range of measured values. However, alternate information may be used to justify a source’s anticipated NO₂/NO_x in-stack ratios, such as manufacturer test data, state or local agency guidance, peer-reviewed literature, and/or the EPA’s NO₂/NO_x ratio database.”)

³⁷⁶ Gebhart Report at 4.

analysis must apply the most current data and information in the Model Guideline to the Liquefaction plant PSD permit modeling.

F. ADEC Underestimates Maritime Emissions and Fails to Include them in the Increment Analysis

Based on the air quality modeling description in Resource Report No. 9, Appendix D, maritime emissions were considered only when they occurred in the immediate vicinity of the LNG loading dock (within 500 meters).³⁷⁷ As explained in Mr. Gebhart's Report, "[e]missions from the vessels impact air quality at considerable distances from the source and these impacts are not limited to just 500 meters. The 500 meter modeling limitation for maritime emissions was not appropriate nor was it scientifically defensible. The air quality modeling should have considered maritime emissions associated with the project beyond those that occur close to the loading dock." The 500 meter assumption is very limiting and results in an implicit assumption that emissions occurring beyond 500 meters have no impact on air quality concentrations. An arbitrary exclusion of real-world emissions from the modeling goes against the general concept that modeling should attempt to address uncertainties with conservative assumptions.

Furthermore, the AK LNG Project FEIS stated that the maritime emissions were not calculated based on the maximum number of vessels serving the Liquefaction plant,³⁷⁸ and since the PSD permit modeling used the modeling data generated by the Draft EIS, which again was improper, this error also translated to the PSD permit modeling. Therefore, the results in the air quality impacts were underestimated.

Lastly, an impact analysis for maritime emissions transiting the Cook Inlet on the Class I Tuxedni National Wildlife Refuge (TUXE) has not been conducted. These maritime emissions would consume PSD increment and would have the potential to impact the nearby onshore Class I PSD areas. Any increase in emissions from maritime traffic will occur after the minor source baseline date consumes PSD increment. As such, PSD increment consuming emissions would be present not only from maritime traffic travelling to/from the Liquefaction plant, but also from some of the maritime traffic serving other facilities in Kenai and elsewhere in the Cook Inlet. By not properly considering the maritime emissions at the point where such emissions are in the proximity of TUXE, the air quality impacts to this Class I area have been underestimated.

G. Flaring Emission Must Represent Permitted Not "Average" Emission

The air quality modeling included emissions from emergency equipment such as flares, emergency engines, and other sources. However, in many cases, these sources were modeled at their annual average emissions rate, which substantially underestimated short-term emissions, which are allowed under the proposed permit, when these emergency sources actually operate.

³⁷⁷ Resource Report No. 9, Appendix D, at 32.

³⁷⁸ Gebhart Report at 4.

The air quality modeling assessment needed to be based on realistic scenarios for operation of the emergency equipment that accounted for the actual short-term emissions of such equipment when these sources operate. If permitted, the Liquefaction plant will emit flare emissions over a specific period of time, such emissions are not emitted on an annual average. Therefore, the current modeling analysis underestimates the short-term emissions and associated impacts from this equipment.

The emissions modeling for the flaring scenarios are documented in Resource Report #9, Appendix D, Table 4-3. The table below extracts the data on the flaring emissions modeled by the applicant from the EIS documentation. Although this table comes from the EIS documentation, ADEC has asserted that it relied upon the EIS modeling for the purpose of quantifying air quality impacts for the Liquefaction plant PSD permit. Also listed in this table are the operating hours upon which the annual emissions total at the individual flares have been computed.

Figure 4. Flaring Emissions Modeled by the Permit Applicant

Model ID	Description	Op Hrs	NOx (g/sec)		SO ₂ (g/sec)			PM-10/PM-2.5 (g/sec)	
			1-hr	Ann	1-hr	3& 24-hr	Ann	24-hr	Ann
DRYMAX 1&2	Dry Grnd Flare: Max Case	500	29.3	29.3	1.08	3.14	1.08	4.44	12.2
WETMAX 1&2	Wet Grnd Flare: Max Case	500	6.86	6.86	0.251	0.734	0.251	1.04	2.85
LPMAX	Low Press Flare: Max Case	144	0.148	0.148	5.67E-3	0.345	5.67E-3	3.55	5.83E-2

Based on the above table, flaring emissions for compliance with the applicable 1-hour NOx and SO₂ NAAQS were modeled at the annual emissions rate. This approach significantly underestimated the short-term emissions from max case flaring operations as this approach essentially smoothed out flaring emissions over the year instead of modeling the short-term spikes in flaring emissions that would actually occur. Also, flaring emissions would occur with sufficient frequency to affect the form of the standard for the 1-hour NOx and SO₂ NAAQS. For example, the max case flaring emissions may occur up to 500 hours per year for individual flares (based on the ADEC analysis). At 500 hours per year, flaring could occur on a minimum of 21 days per year (e.g., $500/24 = 20.8$), and would likely occur on significantly more days since flaring would not be expected to occur continuously over 500 hours. This means that the frequency of flaring would affect ambient air concentrations on more than 1 percent of all days for the SO₂ NAAQS and more than 2 percent of all days for the NO₂ NAAQS. As such, the

maximum emissions and not the average emissions needed to be modeled for the 1-hour NAQSS compliance analysis.³⁷⁹

When modeling compliance with the 3-hour and 24-hour standards, the LPMAX emissions were modeled using a higher emission rate that appears to be indicative of the maximum short-term emissions rate at this flare. The same approach should have been used for modeling compliance with applicable 1-hour NAAQS.

At the dry/wet ground flares, the SO₂ emissions were modeled for the 3-hour and 24-hour average at a higher emissions rate, although it is unclear how the higher 3-hour/24-hour rate was derived. The data in the table show that the 3-hour/24-hour emissions were increased by about a factor of three above the annual emissions rate. However, extrapolating from 500 hours of annual operation would suggest that the maximum short-term emissions at the various ground flares should have increased by about a factor of about 17.5, e.g., 8760/500. The basis for the factor of three was not explained in the modeling documentation.

For PM-10 and PM-2.5 emissions, the table indicates that the ground flares were modeled at a lower emission rate for the 24-hour modeling compared to the annual emissions, which should never occur. The maximum 24-hour emissions should always be at or above the annual emissions rate. Again, extrapolating from 500 hours of operation would result in a factor of about 17.5 for the increase in the maximum short-term PM-10 and PM-2.5 emissions. The PM-10 and PM-2.5 emission rates in the flare modeling appear to contain a serious error.

H. ADEC Applied a Model That Required But Did not Receive EPA Approval

If the recommended models are inappropriate in a given case, other non-guideline models may be used pursuant to 40 C.F.R. § 52.21(l). That section provides that “[w]ritten approval of the Administrator must be obtained for any” non-guideline model. “In addition, use of a modified or substituted model must be subject to notice and opportunity for public comment ...” *Id.*³⁸⁰

The applicant and ADEC have applied the Shoreline Dispersion Model (SDM) as part of the air quality modeling analysis. SDM is not listed as an approved air dispersion model under 40 C.F.R. 51 Appendix W.

Anytime modeling for a PSD permit applies a non-guideline model, written approval of the EPA Administrator (or the Administrator’s designee) is required. No such approval for SDM has been secured by ADEC and/or the applicant for use in this particular PSD application.

ADEC has claimed that such approval is not required because the SDM was used to “supplement” the AERMOD modeling analysis and AERMOD was in fact the approved model. However, no such distinction for a “supplemental” model is found in 40 C.F.R. 51 Appendix W. Appendix W discusses “Preferred Models” (Section 3.1) and “Alternative Models” (Section 3.2). There are no other categories for models as has been suggested by ADEC. In addition, any

³⁷⁹ PSD modeling must reflect worst-case emission rates of (i.e., the maximum allow emission rate under the permit) for each pollutant.

³⁸⁰ 18 AAC 50.040(h)(10), incorporating by reference 40 C.F.R. § 52.21(l).

attempt to supplement a “preferred model” such as AERMOD would constitute a modification to the approved model. Appendix W specifically prohibits modifying a “preferred” model without subjecting to model to the “alternative model” approval requirements of Appendix W.

Given that SDM is not on the list of EPA “Preferred Models,” its use in the Liquefaction Plant PSD permit application is by default as an “Alternative Model.” Under Appendix W, the use of any “Alternative Model” is subject to the procedures for EPA Administrator approval listed in Section 3.2 of Appendix W. ADEC’s failure to secure written EPA Administrator approval for SDM under the “Alternative Model” procedures means that the PSD permit cannot be issued.

Additionally, ADEC’s TAR explains that for characterization of the off-site horizontal stacks in the AERMOD analysis, AGDC used the “POINTHOR and POINTCAP options to characterize the off-site EUs with horizontal/capped stacks,”³⁸¹ which ADEC further suggests received the required case-specific approval from EPA.³⁸² ADEC’s proposal does not indicate whether the EPA personnel that approved the alternative was authorized by the agency.

I. ADEC Failed to Consider Secondary PM Impacts

From the information in the TAR, secondary pollutants impacts, such as formation of sulfate and nitrate which would be additive to the primary PM-10 and PM-2.5, were not addressed in the air quality modeling analysis for the AK LNG Project Liquefaction plant. This is critically important in the case of the Liquefaction plant PSD permit, because the modeling of primary PM-10 and PM-2.5 showed results that were at or near the applicable Class II PSD increment at Kenai National Wildlife Refuge, which ADEC explained is approximately 10 km distant.³⁸³ Based on Table 10 in the ADEC TAR, the 24-hour Class II PM-10 modeling listed a modeled concentration of 29.7 micrograms per cubic meter at Kenai versus the Class II PSD increment of 30 micrograms per cubic meter. Similarly, TAR Table 10 lists the modeled PM-2.5 24-hour concentration at 8.7 micrograms per cubic meter at Kenai vs the Class II increment of 9 micrograms per cubic meter.

³⁸¹ PreTAR at 23.

³⁸² *Id.* See also PreTAR at 4 (“The ambient demonstrations submitted in support of a permit application must comply with the air quality models, databases, and requirements specified of 40 C.F.R. 51, Appendix W (*Guideline on Air Quality Models*), per 18 AAC 50.215(b), or an alternative modeling approach approved under 18 AAC 50.215(c). This basic requirement is reiterated for PSD applicants in 40 C.F.R. § 52.21(l), which the Department has adopted by reference in 18 AAC 50.040(h)(10).”)

³⁸³ PreTAR at 32, which further explains that the Class II Sensitive areas subject to evaluation include the Kenai NWR, Chugach National Forest, Lake Clark National Park and Preserve, Kenai Fjords, and Kodiak National Wildlife Refuge.

Figure 5. ADEC Modeling Analysis Results Demonstrate Impacts At and Near the PSD Increment.³⁸⁴

Table 10. Maximum Modeled Impacts Compared to the Class II Increments

Pollutant	Avg. Period	Modeled Design Conc. (µg/m ³)	Max. one-hour Fumigation Conc. (µg/m ³)	Total Impact (µg/m ³)	Class II Increment (µg/m ³)
NO ₂	Annual	12.5	Included	12.5	25
PM-10	24-hour	24.7	5.0	29.7	30
	annual	2.7	5.0	7.7	17
PM-2.5	24-hour	8.7	Included	8.7	9
	Annual	1.3	Included	1.3	4
SO ₂	three-hour	39.6	5.7	45.4	512
	24-hour	17.5	5.7	23.3	91

The modeling results showed no margin of compliance with the Class II PSD increment and it is highly likely that if the increased PM-10 and PM-2.5 associated with secondary emission had been properly considered, the modeling results would in fact have exceeded the applicable Class II PSD increment for PM-10 and/or PM-2.5.

Additionally, ADEC failed to consider impacts from the maritime and terminal NO_x and VOC emissions, which must be included in the secondary impacts analysis for PM-10/PM-2.5 and ozone referenced above.

Further, an approach was by EPA for quantification of such impacts, specifically Modeled Emission Rates for Precursors or MERPs.³⁸⁵ This approach should have been considered by the applicant and by ADEC to address secondary particulate matter (PM) impacts. The draft EPA MERPs report was published in late 2016 and used for PSD permitting upon release.³⁸⁶ Therefore, the draft 2016 EPA guidance “Draft Guidance on the Development of

³⁸⁴ *Id.*

³⁸⁵ EPA, “Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM_{2.5} under the PSD Permitting Program,” EPA-454/R-19-003 (April 2019), available at <https://www.epa.gov/sites/production/files/2019-05/documents/merps2019.pdf>.

³⁸⁶ EPA, “Draft Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM_{2.5} under the PSD Permitting Program,” (Dec. 1, 2016), available at <https://nepis.epa.gov/Exe/ZyNET.exe/P100QQWB.TXT?ZyActionD=ZyDocument&Client=EPA&Index=2016+Thru+2020&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfles%5CIndex%20Data%5C16thru20%5CTxt%5C00000001%5CP100QQWB.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL> (this draft guidance was used for PSD permitting upon release).

Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM_{2.5} under the PSD Permitting Program, was available for use by the applicant on this project well before the PSD application was filed. The EIS appears to have attempted to address secondary PM impacts; however, this effort does not appear to have been carried over into the PSD permit modeling. Without considering these secondary PM impacts, the liquefaction modeling analysis for the PSD permit is incomplete and underestimated the real-world air quality impacts of the project.³⁸⁷

The adjacent Agrium fertilizer facility also should have been considered. Based on Resource Report #9, Appendix D, Agrium has estimated ammonia emissions of approximately 700 tons per year.³⁸⁸ These ammonia emissions would be expected to react with project-related NO_x and SO₂ emissions to form secondary PM in the near-field and increase PM-10 and PM-2.5 above those concentrations explicitly modeled by the applicant. The nearby ammonia emissions, the potential for formation of secondary PM and the associated increase in PM-10 and PM-2.5 concentrations cannot be ignored, especially given that the current PSD permit modeling has virtually no margin of safety with respect to compliance with Class II PSD increments. The secondary PM as described would be additive to the primary PM-10 and PM-2.5 otherwise modeled and these increases would likely cause the Class II PSD increments to be exceeded in the vicinity of the Liquefaction plant.

The transport of nearby ammonia emissions from Agrium would also extend downwind to nearby Class I areas (see separate Class I comments below).

J. The Permit Fails to Include Enforceable Limits to Address Impacts to the AQRVs at the Class I Areas

With respect to required Class I Impact analysis,³⁸⁹ AGDC's Class I modeling analysis, upon which ADEC's proposed approval relies, clearly documents adverse air quality impacts at both TUXE and DNPP. And while disclosed by ADEC's PreTAR, the FEIS identified numerous

³⁸⁷ Furthermore, we note that EPA's Webinar (Jan. 19, 2017)(enclosed and available at https://www3.epa.gov/ttn/scram/appendix_w/2016/MERPs_WebinarPresentation_01192017.pdf) provided detailed information on EPA's rulemaking and revisions to the Guideline on Air Quality Models (82 Fed. Reg. 5182 (Jan. 17, 2017) (Revisions to the Guideline on Air Quality Models: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches To Address Ozone and Fine Particulate Matter.) EPA's final rulemaking webinar cited to the 2016 MERP guidance documents as to the recommended procedures for the secondary pollutants analysis. The Appendix W guidelines are in Section 5.3 for ozone and Section 5.4 for PM-10/PM-2.5. While Appendix W Section 5.4 refers to PM-2.5, since PM-2.5 is a subset of PM-10, the secondary PM-2.5 determined by the MERPs procedure is also additive to the PM-10 modeling. Finally, EPA's proposed rulemaking further discussed the purpose of MERPs for ozone and secondary PM_{2.5} precursors in the permitting context. 80 Fed. Reg. 45340, 45348 (July 29, 2015)

³⁸⁸ Based on information included in ADEC's proposed approval of Agrium's recently submitted request for a new PSD permit to construct, if permitted and constructed, the potential to emit for ammonia would be 634 tpy. See, Agrium Permit Application at PDF 182.

³⁸⁹ 18 AAC 50.306(h)(4). which adopts 40 C.F.R. § 52.21(p) by reference.

exceedances of sulfur and acid deposition thresholds, nitrogen deposition thresholds and visibility thresholds.³⁹⁰

Given these impacts, ADEC was required to – and did not – consult with and address FLM concerns prior to providing public notice on its proposed permit action,³⁹¹ which we discuss elsewhere in our comments. Moreover, if the proposed action will likely cause or contribute to an adverse effect to air quality related values, the federal land manager (FWS or the NPS may recommend permit conditions that ensure mitigation, including stricter emissions controls and effective emissions offsets. If no mitigation is possible, NPS or FWS may recommend denial of the permit.³⁹² While this is a procedural error, more importantly the fact the ADEC did not follow the procedures to consult with the FLMs **before proposing the permit** means that ADEC failed to address FLM comments and concerns regarding the significant AQRV impacts at the national park and wilderness area in its proposed permit action.

As Mr. Gebhart’s report explains, ADEC acknowledges in the PreTAR that the proposed project will adversely impact the Class I areas. But then ADEC then goes on to assert that such adverse impacts were not of regulatory significance. In the first part of its analysis, ADEC attempts to characterize the results from the VISCREEN analysis at the Kenai NWR as “negligible.”³⁹³ ADEC basis its characterization on the following assertions: accurate model inputs were used; and “the relative isolation of these estimated deviances at a Class II Sensitive area is not sufficient to warrant further regulatory inquiry, *ceteris paribus*.”³⁹⁴ Finally, ADEC

³⁹⁰ See FEIS at 4-943 (nitrogen deposition impacts from gas treatment plant would exceed deposition thresholds for the Arctic National Wildlife Refuge (“the Refuge”)); id. at 4-955 (sulfur deposition thresholds could be exceeded by air emissions from the Galbraith Lake Compressor Station at the Refuge); id. at 4-974 (LNG emissions “could have a long-term significant impact on acid deposition at the Tuxedni NWR, DNRR, Kenai NWR, and Lake Clark NPP”); id. at 4-958, Tbl. 4.15.5-19; 4-955 (“compressor station and heater station operation could have significant impacts on ecosystems from nitrogen deposition in Class I and Class II nationally designated protected areas”); id. at 5-42 (“the FLM-established visibility threshold and sulfur deposition threshold at the Arctic National Wildlife Refuge could be exceeded by emissions from the Galbraith Lake Compressor Station. FLM-established nitrogen deposition thresholds at multiple Class I and II areas—including Arctic National Wildlife Refuge, Gates of the Arctic NPP, Gates of the Arctic Preserve, Yukon Flats NWR, Kanuti NWR, DNPP, and Kenai NWR—could also be exceeded by operation of the stations”).¹⁴⁶ Such emissions would also harm visibility in these areas, degrading the quality of recreation. See, e.g., FEIS at 4-943 (visibility impacts from the gas treatment plant could exceed threshold at the Refuge); id. at 4-943 (identifying cumulative impacts to visibility in the Refuge and Gates of the Arctic National Park and Preserve); id. at 4-946 (gas treatment plant emissions would exceed the visibility change threshold at the Refuge and “could have a long-term significant impact on regional haze at [the Refuge]”); id. at 4-974 (LNG emissions could have a significant impact on regional haze at the Kenai NWR); id. at 4-955 (visibility plume perceptibility thresholds could be exceeded by the Galbraith Lake Compressor Station at the Refuge and by the Healy and Honolulu Creek Compressor Stations at the Denali National Park and Preserve).

³⁹¹ For example, the FLMs evaluate visibility impacts are evaluated by looking at the change in light extinction due to pollution. Light extinction is a measure of visibility reduction (degradation) and is inversely proportional to visual range. According to the “Federal Land Managers’ Air Quality Related Values Workgroup (FLAG) Phase I Report,” (2010), Natural Resource Report NPS/NRPC/NRR-2010/232, impacts that change light extinction by more than 5% would be considered to contribute to visibility impairment and impacts that change light extinction by more than 10% would be considered to cause visibility impairment, available at <https://www.fws.gov/guidance/sites/default/files/documents/FLAG%20Air%20Quality%20Phase%20I%20report.pdf>.

³⁹² Id. at 66-67.

³⁹³ PreTAR at 33.

³⁹⁴ Id.

concludes that, “the Department finds AGDC’s modeled results sufficient to provide a reasonable estimation of immaterial near-field visibility impacts.”³⁹⁵

We have numerous concerns with ADEC’s analysis of the VISCREEN results. First, ADEC merely labels the results as “negligible” neither providing a frame of reference nor explaining why the results are negligible. Further, the PreTAR fails to present the actual results, and fails to include a reference to where information on the results is found,³⁹⁶ presenting the adverse impacts as follows:

- A slight deviation from both criteria for the compressor turbine plumes, subject to sky background and backward scatter, at the closest park boundary observer location; and
- An increase in the perceptibility criteria for the compressor turbine plumes, subject to terrain background and forward scatter, at both the closest park boundary and Skilak Lake observer locations.³⁹⁷

Second, as discussed below and throughout our comments, the assumptions used to create the model inputs – from the flawed determination of what constitutes the source, to the detailed modeling inputs and methodology – have serious flaws that are inconsistent with the regulations and Act. Thus, it is unreasonable for ADEC to suggest that the model inputs were “representative-to-conservative” as they clearly were not. Finally, we disagree with ADEC’s assertions that the model results are just mere “deviances” because they come from model estimations. ADEC’s assertion is not supported by any rationale. For example, ADEC fails to explain or justify “deviations,” the relevance of its finding that they are in “relative isolation,” or explain its concerns regarding what it perceives to be model inaccuracies. Such bare assertions without supporting rationale are arbitrary and unreasonable. Additionally, presenting the modeling results as “exceptions” is illogical and unsupported.^[2] The results stand. ADEC provides no support for its a theory that the results from these modeling runs are not consistent with what one would expect from VISCREEN, which is not surprising since models are predictive in nature and moreover, can only be used in this context if they have been approved for use by EPA. Moreover, while uncertainty is inherent to the modeling process, models are the tools Congress specified for use in this context and are what is used by agencies to make permitting decisions. Thus, ADEC cannot supplant the VISCREEN modeling results and meet the purposes of the PSD program based on its proposal.³⁹⁸

ADEC’s Class I AQRC analysis next considers the “source-only” results from the CALPUFF model, explaining that the model showed impacts “to both Class I and Class II Sensitive areas, in terms of regional haze and visibility degradation.” ADEC’s attempts to discount the following results as “immaterial” are also unavailing:

³⁹⁵ PreTAR at 33.

³⁹⁶ A permitting agency must present information for public review in a clear manner. ADEC goes at great lengths in other portions of its PreTAR to present the fine details, and yet when it comes to the AQRV impacts at the Class I and Class II areas, neither details nor a citation as to where one can find the information are provided.

³⁹⁷ PreTAR at 33.

^[2] *Id.* at 33.

³⁹⁸ Furthermore, ADEC’s discussion fails to include the FLMs comments and concerns regarding these adverse AQRV impacts to the lands they have an affirmative to protect.

- For **regional haze** the modeling results showed impacts to both Class I and Class II Sensitive areas,
- For **visibility degradation** the modeling results showed impacts to both Class I and Class II Sensitive areas, and
- The **deposition analysis** indicates sulfur and nitrogen flux results above the respective deposition analysis thresholds (DATs) at several locations.

We disagree with ADEC's supporting discussion of the CALPUFF results based on the following. In assessing the impacts to regional haze and visibility, ADEC divides the impacts into two categories and characterizes them as follows: (1) "slight exceedances [of regional haze and visibility degradation] at Lake Clark National Park in model years 2003 and 2004;"³⁹⁹ and regional haze and visibility impacts to "both Class I and Class I sensitive areas ... that fall below the five-percent extinction threshold at all areas evaluated."⁴⁰⁰ As they neglected to do in the VISCREEN analysis, ADEC fails to include any of the model results in the PreTAR and does not provide a reference where the public can review the information. The suggestion that impacts are "slight" is unsubstantiated, ADEC does not explain what the actual results show, why they are "slight" and how the results compare to some apparent metric upon which they assess impacts. Further, in mentioning the exceedances were only found in two of the model years (2003 and 2004), without providing any justification, ADEC appears to further discount the results. This is illogical. The CALPUFF model is run over a series of years of meteorological data to represent a variety of conditions. The fact that exceedances are seen in some years and not others is not an anomaly since weather patterns change from one year to the next. ADEC further offers that for all the Class I and Class II Sensitive areas impacted – with the exception of Lake Clark National Park – "regional haze and visibility degradation ... fall below the five-percent extinction threshold."⁴⁰¹ ADEC does not explain the basis for using this threshold, nor does it explain how close the results are to this threshold. Without explaining what "cumulative values" it refers to, ADEC further suggests that it understands

[T]hese cumulative values may be compelling when considered in the absence of additional information.⁴⁰²

Although ADEC suggests there is "additional information," in reality none is provided. First, without explaining how and why plant operation impacts its decision, ADEC suggests "there is no cause for regulatory concern at the former areas with regard to significant visibility impairment attributable to operation of the Liquefaction plant as proposed."⁴⁰³ Moreover, ADEC's next piece of information is also unreasonable, it offers that "mode uncertainty and conservative operational assumptions suggest estimated impacts attributable to the Liquefaction plant may be overstated."⁴⁰⁴ There is nothing to support this statement. The public is left wondering: what does ADEC mean by "mode uncertainty" ... and by "conservative operational assumptions ... and how does the uncertainty and operational assumptions relate to the CALPUFF model inputs? None of this information is disclosed. For a permitting agency to rely on source operating parameters to limit

³⁹⁹ PreTAR at 33-34.

⁴⁰⁰ PreTAR at 34.

⁴⁰¹ PreTAR at 33-34.

⁴⁰² *Id.* at 34.

⁴⁰³ *Id.*

⁴⁰⁴ *Id.*

emissions and thereby protect the AQRVs, ADEC must disclose what “mode” and “operation” it assumes, and include those assumptions in the proposed permit. Providing a clear link between the assumptions made and how they will be enforced under the Act. None of which is provided in ADEC’s proposal.

Finally, ADEC’s PreTAR attempts to explain why the acidic deposition impacts are immaterial. The sulfur and nitrogen flux results are neither included in the PreTAR, nor has the ADEC indicated to the public where it can find them. ADEC discloses that the “sulfur and nitrogen flux results above the respective deposition analysis thresholds (DATs) at several locations,” but does indicate the locations impacted. Without explaining what this means, ADEC notes that “Denali is the only Class I area among the former.”⁴⁰⁵ ADEC next attempts to discount the results by suggesting the impacts from sulfur are higher than those from nitrogen. Since impacts from both are above the threshold, all impacts are of concern, it is unreasonable for ADEC to suggest otherwise. Further, without describing what the “cumulative deposition analysis” included, nor where one can find the results, ADEC suggest “the results are below the DAT at all locations.”⁴⁰⁶ ADEC’s suggestion that by relying on “potential” qualities in the natural-gas and “operational assumptions” “would likely obviate the sulfur deposition concerns at the Class II Sensitive areas modeled.”⁴⁰⁷ ADEC does not provide any details on what it suggests relying on. It does not provide the basis for “AGDC’s position” regarding potential for gas that is different than what was modeled. Further, ADEC points to nothing in the permit that reflects this assumption. Moreover, it is similarly unclear what and how “operational assumptions” might impact the areas modeled; and further no explanation of whether those operational assumptions are reflected in the proposed permit. ADEC also offers that the nitrogen impacts would also be mitigated by “said conservatism of operational assumptions, largely predicated upon AGDC’s greater than anticipated ‘normal’ modeled operational scenario.”⁴⁰⁸ ADEC’s attempt to discount the nitrogen impacts fail for the same reasons outlined above. Further, neither AGDC nor ADEC present revised modeling results to support the myriad of assumptions.

Furthermore, FERC’s FEIS discloses that it issued information requests requesting that AGDC provide information about the “mitigation strategy.”⁴⁰⁹ It appears AGDC did not respond to FERC’s request.

In sum, ADEC cannot proceed with the Liquefaction plant PSD permit without first addressing the adverse Class I impacts that have been identified. ADEC should have fully disclosed to the public the FLM findings when it proposed the permit and required adoption of appropriate measures to address the adverse impacts and made implementation of such measures enforceable permit requirements. As presented in the Draft PSD permit and PreTAR, ADEC has not fulfilled its regulatory and statutory obligations to protect AQRVs and other resources in the affected Class I areas. Furthermore, not only has ADEC failed to meet these requirements, as discussed in the next section, the methodology upon which ADEC relied is incomplete, inaccurate and inconsistent in its assumptions.

⁴⁰⁵ *Id.*

⁴⁰⁶ *Id.*

⁴⁰⁷ *Id.* (“The Department notes that AGDC’s position regarding an in-situ potential for “sweeter” than modeled pipeline-quality fuel gas and conservative operational assumptions.”)

⁴⁰⁸ *Id.*

⁴⁰⁹ *See* FEIS at 4-943 (“While preparing the draft EIS, we issued information requests on July 28, 2017 and February 15, 2018 to AGDC requesting that they work with the FLMs to establish a mitigation strategy to ensure that air emissions from the proposed facilities would not negatively affect nearby Class I and Class II nationally designated protected areas. To date, AGDC has not provided a mitigation strategy or determined acceptable thresholds agreed upon by the FLMs.”).

K. The Class I Modeling Analysis Is Incomplete, Inaccurate and Inconsistent in its Assumptions

Notwithstanding the above, the Class I modeling has technical errors and the result is that Class I impacts at TUXE and DNPP have been underestimated. These technical errors are documented below.

The cumulative air quality modeling was incomplete with respect to Class I impacts. For example, the modeling for the Liquefaction plant did not completely address all project-related impacts to Denali National Park and Preserve (DNPP). Several of the pipeline compression facilities associated with the AK LNG Project would be in close proximity to DNPP. For example, the Healy Compressor Station would be located within 5 kilometers of DNPP and the Honolulu Creek Compressor Station would be located within 14 km of DNPP. Based on the data presented in the TAR, the pipeline compressor station emissions were not included in the Class I air quality modeling. However, these compressor stations emissions are part of the AK LNG Project and their impacts should have been evaluated. Also, any such emissions would occur after the PSD minor source baseline date and as such, would consume PSD increment at nearby Class I areas such as DNPP. Likewise, these emissions have the potential to adversely impact AQRVs such as visibility and acid deposition. The compressor station emissions needed to be addressed in combination with the Liquefaction plant for the Class I analysis at DNPP; otherwise, the analysis was incomplete with respect to air quality impacts, including PSD increment along with air quality related values (AQRVs) such as visibility and acid deposition.

In the CALPUFF modeling, the selected years for meteorological data and other inputs was 2002-04. As such, the background ozone data used in CALPUFF were also from 2002-04, which meant that the ozone data input to CALPUFF were more than 15 years old. The CALPUFF modeling should have been based on more recent data so that it would be representative of current conditions.

The CALMET modeling used to derive the CALPUFF meteorological fields was not consistent with current EPA/FLM guidelines (See: Clarification on EPA-FLM Recommended Settings for CALMET; USEPA Memo dated August 31, 2009). For example, the vertical layers assigned in CALMET/CALPUFF did not match the 2009 EPA/FLM guidelines. There may have been other deviations from the 2009 EPA/FLM guidelines, but that could not be determined from the information presented in Resource Report No. 9, Appendix D.

As noted in earlier comments above, errors exist in specification of emissions associated with flaring as well as emissions associated with maritime traffic. These errors also translate to the Class I modeling analysis.

Finally, as noted in comments above, the Agrium fertilizer plant located adjacent to the Liquefaction plant site is a very large source of ammonia emissions. It is likely that these ammonia emissions would be transported along with emissions from the proposed Liquefaction plant to nearby Class I areas. The ammonia emissions would interact with the Liquefaction plant

NO_x and SO₂ emissions to form ammonium sulfate and ammonium nitrate during the downwind transport to these nearby Class I areas and cause increased impacts to AQRVs such as visibility and acid deposition. This is contrary to the applicant's claims in the CALPUFF modeling that the Liquefaction plant emissions would exist in an ammonia-limited environment. The ammonia emissions associated with the adjacent Agrium plant were not considered in the Class I impact modeling relied upon by ADEC. As such, the reported impacts to Class I areas such as DNPP and TUXE were underestimated.

L. ADEC's Public Notice Failed to Provide the Degree of Increment Consumption Expected at the Source at the Class I Areas

The Clean Air Act requires meaningful public participation in the PSD permitting process. Section 165(a)(2) requires a public hearing allowing for interested persons "to appear and submit written and oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations." In implementing this provision, ADEC adopts EPA's regulations defining the requirements for state PSD plans, which require the reviewing authority to:

Notify the public, by advertisement in a newspaper of general circulation in each region in which the proposed source would be constructed, of the application, the preliminary determination, *the degree of increment consumption that is expected from the source or modification*, and of the opportunity for comment at a public hearing as well as written public comment.

40 C.F.R. § 51.166(q)(2)(iii) (emphasis added).⁴¹⁰ ADEC's public notice for the draft permit was defective because it failed to include the predicted amount of increment consumption in the Class I areas. The regulation specifically requires these data to be in the public notice. "To allow for meaningful comment, the public must be apprised of all of the proposed source's increment consumption as determined through the modeling analysis."⁴¹¹ Furthermore, "[d]ifferent potential commenters may have an interest in different areas to be impacted and would want, and would reasonably be entitled to, available data on increment consumption at the area of their particular concern. Otherwise, their ability to comment on the air quality impact and proposed alternatives would be severely limited."⁴¹² Therefore, ADEC should "provide a new public notice ... and such notice should detail all of the increment to be consumed by the proposed source, including any increment consumed"⁴¹³ at the Class I areas.

⁴¹⁰ ADEC adopts many of the PSD regulations by reference, including this one. EPA last approved ADEC's adoption by reference in 2014, when ADEC adopted the version of this rule [via 18 AAC 50.040(h)(2)] that was revised by EPA as of July 1, 2011. 79 Fed. Reg. 56268 (Sept. 19, 2014).

⁴¹¹ *Hadson Power* at 272.

⁴¹² *Id.*

⁴¹³ *Id.*

M. ADEC Erred in Categorically Excluding Construction Emissions from the Air Quality Analysis.

Section 165(a)(3) of the Clean Air Act, provides that no major emitting facility may be constructed unless “the owner or operator of such facility demonstrates ... that emissions from construction or operation of such facility will not cause or contribute to air pollution in excess of [any applicable PSD increment or national ambient air quality standard.].” In addition, the Clean Air Act prohibits construction, not just operation, prior to permit issuance. In addition to the language of section 165(a)(3) itself, the requirement to consider construction emissions is clearly demonstrated by the inclusion of “construction” throughout the PSD regulations.⁴¹⁴

Construction emissions were not modeled for the PSD permit. However, given the duration of construction anticipated to be eight years and the phased nature of construction for the proposed activity included in this permit and the other emitting units that must be made part of this source, as Mr. Gebhart’s Report explains, it should be apparent that construction of later project phases would overlap with initial project operations. ADEC’s analysis needs to address modeling scenarios where project construction would overlap with the initial project operations in order to provide for a full and complete air quality modeling analysis.⁴¹⁵ As discussed above, ADEC must first obtain the applicants construction schedule in order to conduct this analysis. If the modeling does not include construction emissions and acknowledge the likely overlap with startup and operation emissions, it will be inaccurate and misleading.⁴¹⁶

Mr. Gebhart’s Report further notes that it is not enough that the permit has included PM-10 and PM-2.5 monitoring requirements during the construction phase ... these monitoring requirements only provide for measurements against the NAAQS, and fail to assure that the permit conditions will actually protect the NAAQS. Furthermore, the construction-related emissions would occur after the minor source baseline date and as such, the construction emissions also consume PSD increment and were not included in the increment analysis. The monitoring program contemplated under the permit would not be capable of demonstrating whether the construction-related emissions might cause or contribute to possible violations of the Class II PSD increment for PM-10 and PM-2.5. Therefore, an accurate PSD increment assessment that addresses construction-related emissions is required, which would be best achieved through air quality modeling conducted in accordance with the Modeling Guideline and other requirements.

N. ADEC Erred in Equating the Soils and Vegetation Impact Analysis with the NAAQS Analysis

⁴¹⁴ See e.g., 40 C.F.R. 52.21(b)(2), (b)(48)(iii).

⁴¹⁵ Gebhart Report at 11.

⁴¹⁶ Notably, the revised construction schedule AGDC provided during the DEIS comment period led to the disclosure in the FEIS that simultaneous construction, startup, and operation of the Liquefaction Facilities “could lead to short-term air quality impacts” such that a monitoring plan would need to be implemented to monitor air quality and manage exceedances. FEIS, App. CC at CC-583; see also Order ¶ 210.

The PSD regulations require that the permit applicant “provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source ... and general commercial, residential, industrial and other growth associated with the source” 40 C.F.R. § 52.21(o). This requirement is often referred to as the “additional impacts analysis.” The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.” 40 C.F.R. § 52.21(o)(1); *see In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 130 (EAB 1997). Generally, the additional impact analysis consists of four parts: (1) impairment to visibility; (2) soils and vegetation impacts; (3) ambient air quality impact; and (4) growth expected as result of the source or modification. *See* 40 C.F.R. § 52.21(o). For the impacts to soils and vegetation, the permitting authority must consider the impacts of growth associated with the proposed Liquefaction plant as well as the impacts of pollutants for which there are no NAAQS. The PreTAR acknowledges these requirements.⁴¹⁷

For the soils and vegetation analysis, the ADEC PSD permit analysis relies solely on compliance with NAAQS to address possible adverse impacts to soils and vegetation. This approach is wholly inadequate. The NAAQS do not cover all pollutants and therefore are not intended to be protective of all soils or all vegetation species. If the NAAQS adequately protected all species from harmful effects of air pollution, there would be no need for the separate soils and vegetation analysis required by the PSD regulations at 40 C.F.R. § 52.21(o)(1).⁴¹⁸ Instead, ADEC should instruct the applicant to inventory soils and vegetation species present in the area impacted by the entire AK LNG Project to determine the presence of species that may be particularly sensitive to adverse impacts from air pollution.⁴¹⁹ Special attention should be paid to any threatened and endangered species that exist in the region. The EIS already contains local/regional data on soils and vegetation that could assist in conducting a soils and vegetation assessment consistent with the basic requirements of the underlying PSD regulations.⁴²⁰ Relatedly, Appendix Q contains the “Recreation Areas Affected by the Project,” and it could also assist in analyzing the impairment to vegetation of recreational value and well as other reports prepared.⁴²¹

⁴¹⁷ PreTAR at 35. And while ADEC acknowledges these regulations, explains that “AGDC it did not include Pipeline Stations and Gas Treatment Plant [nor any other sources that comprise the Alaska LNG Project] in their Associated Growth Analyses since those stationary sources will not be located in the same area as the Liquefaction Plant. As previously noted in Section 5.6.3 of this report, the ambient impacts associated with each of those stationary sources will be assessed, as warranted, under the permit requirements for that stationary source.” *Id.* For the reasons described earlier in these comments, we also disagree with ADEC’s unsupported assertion here.

⁴¹⁸ 18 AAC 50.040(h)(10), incorporating by reference 40 C.F.R. § 52.21(o) Additional impact analyses.

(1) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

(2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

(3) Visibility monitoring. The Administrator may require monitoring of visibility in any Federal class I area near the proposed new stationary source for major modification for such purposes and by such means as the Administrator deems necessary and appropriate.

⁴¹⁹ Gebhart Report at 11.

⁴²⁰ FEIS at 4-943.

⁴²¹ FEIS, Appendix Q, included as an enclosure. Additionally, the following could also assist with this analysis and are included with these comments: FEIS Appendix O (information on critical habitat, which could also assist in

Additionally, for several of the facilities that must be considered part of this PSD permit analysis, the Final EIS explains that there would be the following impacts as Class I and Class II areas

- Operation of the Galbraith Lake Compressor Station could have a significant plume impact at ANWR⁴²²
- Compressor station and heater station operation could have significant impacts on ecosystems from nitrogen deposition in Class I and Class II nationally designated protected areas⁴²³
- Nitrogen deposition impacts from gas treatment plant would exceed deposition thresholds for the ANWF⁴²⁴
- Emissions from the aboveground facilities, including the GTP, compressor stations, heater station, and Liquefaction Facilities, could cause exceedances of visibility extinction thresholds⁴²⁵
- Sulfur deposition thresholds could be exceeded by air emissions from the Galbraith Lake Compressor Station at the Refuge,
- LNG emissions *could have a long-term significant impact on acid deposition at the Tuxedni NWR, DNRR, Kenai NWR, and Lake Clark NPP.*⁴²⁶

Moreover, despite these impacts, no “additional mitigation measures” as identified in the analysis upon which AGDC relied for its permit application,

O. ADEC’s Use of Sensitivity Modeling Fails

ADEC uses sensitivity modeling in an attempt to demonstrate that the errors introduced by not following the current Guideline did not significantly impact the modeling results and that not following the Guideline shouldn’t matter. As discussed in Mr. Gebhart’s report and presented here, ADEC’s attempt to defend the flawed modeling using a sensitivity analysis similarly fails.

The underlying air quality modeling reports from the AK LNG Project EIS (and by extension, the Liquefaction plant PSD permit) were outdated. The Appendices to Resource Report No. 9 that described the air quality modeling methods and results dated to 2017, and in some cases, the actual modeling studies described in Resource Report No. 9 were even older.

There are significant issues with using outdated air quality modeling studies. First, the

considering the impacts); FEIS Appendix P (special status species list, which includes the region impacted, habitat impacted, as well as what portion of the proposed AK LNG Project will impact a particular species and the potential impacts); FEIS Appendix V (includes and relies of information on the potentially affected communities, which could be used to assist in analyzing the air quality impact of the AK LNG Project as a result of general commercial, residential, industrial and other growth associated with the source); FEIS Appendix Z includes a list of more than one hundred pages of references, at approximately 10 references per page, no doubt that information could also assist.)

⁴²² FEIS at 4-673.

⁴²³ *Id.* at 4-955.

⁴²⁴ *Id.* at 4-955

⁴²⁵ *Id.* at 4-955.

⁴²⁶ *Id.* at 4-974.

EPA models used for the Draft EIS air quality impact assessment have been revised and newer versions of the air quality models such as AERMOD and CALPUFF have been released by EPA. Also, using outdated information adversely impacted the cumulative modeling studies in that new emission sources not previously identified may have been constructed and/or proposed since the air quality modeling studies were conducted. In addition, emissions at off-site modeled sources may have changed. The air quality modeling studies need to: 1) use the current versions of the EPA dispersion models and 2) model cumulative air quality impacts using current and relevant emissions data.

To some extent, ADEC recognized that flaws existed from using the outdated EIS modeling analysis. ADEC then conducted so called “sensitivity studies” in a misguided attempt to defend the flawed modeling. However, the ADEC “sensitivity studies” were themselves flawed in several major respects: 1) these studies were limited in that they were applied only to a small subset of the EIS modeling results, 2) these studies looked at modeling errors on an individual basis and did not address the potential cumulative effect of all relevant modeling errors, and 3) the sensitivity studies did not address all modeling errors that carried over from the EIS.

ADEC’s own permit review analysis recognized that the EIS modeling was technically deficient and not up to current standards for a PSD permit. ADEC should have instructed the applicant to update the modeling so that the permit could rely on modeling results that were created under current modeling procedures and standards. Instead, ADEC erroneously chose a convoluted process to defend its reliance on outdated dispersion modeling created for the EIS.

P. ADEC’s Modeling Analysis Failed to Address Secondary Emissions Associated from Growth Impacts

Secondary emissions are defined as:

[E]missions which would occur as a result of the construction or operation of a major stationary source ... but do not come from the major stationary source ... itself. Secondary emissions include emissions from any off-site support facility which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source⁴²⁷

Secondary emissions arise from residential, commercial and industrial growth that accompanies the new activity at the source.⁴²⁸ For PSD review, “[s]econdary emissions must be specific, well-defined, quantifiable, and impact the same general area as the stationary source ... undergoing review.”⁴²⁹

ADEC’s proposal suggests that

⁴²⁷ 40 C.F.R. § 52.21(b)(18). 18 AAC 50.040(h)(4)(adopts by reference the definitions in 40 C.F.R. § 52.21(b), which includes the definition of secondary emissions in 40 C.F.R. § 52.21(18).

⁴²⁸ 40 C.F.R. § 52.21(o).

⁴²⁹ *In re Encogen Cogeneration Facility*, 8 E.A.D. 244, 258 (EAB 1999), citing *Knauf I* at 166 (quoting NSR Workshop Manual at A. 18)(internal quotations omitted); *see also* 54 Fed. Reg. 27,286, 27,289 (June 28, 1989).

The only secondary emissions that would occur due to the construction and operation of the Liquefaction plant are the construction emissions that would occur within the local area. The emissions that would occur due to the remaining aspects of the AK LNG Project, including the construction/operation of the Pipeline Stations and the Gas Treatment Plant, are not secondary emissions for purposes of the Liquefaction plant PSD review since they will not occur in the same general area as the Liquefaction plant emissions.⁴³⁰

ADEC's analysis and proposed conclusions regarding the need to address secondary emissions associated with construction and operation are misplaced. As presented earlier in these comments, not only is it inconsistent with the PSD regulations to exclude emitting units in the source determination, it is similarly inconsistent to ignore them when analyzing impairment to visibility, soils and vegetation that would occur as a result of the source and general commercial, residential, industrial and other growth associated with the source growth impacts. Once a proper source determination is made, the "general area" of the stationary source includes the general area around all the emitting units that comprise the AK LNG Project. Contrary to ADEC's assertions, the "area" is not limited to the Liquefaction plant. Furthermore, ADEC references an EPA memo from 1981, suggesting that EPA's guidance clarifies that for purposes of the secondary emission inventory

[T]he definition in 40 CFR 52.21(b)(18) "sets out four tests to be used in determining whether such emissions are to be included in air quality impact assessments for PSD purposes: the emissions must be specific, well defined, quantifiable, and impact the same general area."⁴³¹

The guidance ADEC refers to in its footnote is an EPA letter from Edward F. Tuerk (Acting Assistant Administrator for Air, Noise and Radiation) to Allyn M. Davis (Director, Air and Hazardous Materials Division), regarding "PSD Evaluation of Secondary Emissions for Houston Lighting and Power." Although ADEC did not include a citation to where the memo can be found or the memo in its proposed action, we found the memo in EPA's "New Source Review Prevention of Significant Deterioration and Nonattainment Area Guidance Notebook," Volume I, dated January 1989.⁴³² In applying the phrase "impact the same general area," EPA's memo explained that "the scope of any required analysis has to be limited to those areas where both secondary and primary emissions are known to occur."⁴³³ To summarize:

EPA's 1981 memo addressed the question of whether emissions from the mine mouth plant needed to be included in the power plant's modeling analysis. Additionally, the memo looked at the provisions for Total Suspended Particulate Matter (TSP) and SO₂ impacts at Class II and Class III areas as set forth in EPA's Emission Offset Interpretive Ruling and the preamble to the 1978 PSD regulations (43 Fed. Reg. 26398 (June 19, 1978)), noting that the mine and power plant were under different ownership.

⁴³⁰ PreTAR at 5.

⁴³¹ PreTAR at 17.

⁴³² A copy of this guidance enclosed.

⁴³³ EPA, "New Source Review Prevention of Significant Deterioration and Nonattainment Area Guidance Notebook," Volume I (Jan. 1989), Edward F. Tuerk (Acting Assistant Administrator for Air, Noise and Radiation) to Allyn M. Davis (Director, Air and Hazardous Materials Division), regarding "PSD Evaluation of Secondary Emissions for Houston Lighting and Power," at PDF 411-412 (March 17, 1981).

Furthermore, the modeling analysis performed demonstrated that the proposed power plant would not cause a significant ambient concentration of TSP at any of the Class II and Class III areas. Thus, the memo recommended that it was not necessary to consider the emissions from the mine as secondary emissions since they do not impact any area of significant impact which would be created by the direct emissions from the proposed power plant.⁴³⁴

The facts in EPA's 1981 memo are clearly inapposite to the AK LNG Project (as well as the proposed Liquefaction plant). EPA's memo looked at two sources under different ownership, while the AK LNG Project is all under the same ownership. Additionally, modeling done for the question raised back in 1981 showed the proposed power plant did not impact any areas, where that is not the case here. Thus, ADEC's suggestion that EPA's 1981 memo supports excluding emissions based on this secondary emissions theory fails.

Q. ADEC's Assessment of NAAQS Exceedances Differs from FERC's

While both ADEC and FERC relied on the same modeling analysis, the two agencies differ in whether the proposed AK LNG Project will cause exceedances of the NAAQS FERC's FEIS discloses that

During the years that simultaneous construction, startup, and operational activities would occur at the Liquefaction Facilities, which would **likely be Years 7 and 8 of construction, emission levels could result in exceedances of the NAAQS/AAAQS.** AGDC developed and would implement an Ambient Air Quality Monitoring Plan to ensure the emissions associated with simultaneous construction, startup, and operational activities would not result in exceedances of PM10 and PM2.5 ambient air quality standards.⁴³⁵

While ADEC asserts that "AGDC's far-field model results, both source-only and cumulative, indicate estimated ambient concentrations within the modeled areas of Page 33 of 38 concern fall below the respective increments; no violations of the NAAQS/AAAQS are seen."⁴³⁶ Although this assertion from ADEC is in a paragraph referring to the FERC Report, ADEC fails to provide a citation. It is deeply concerning that ADEC neither disclosed nor addressed these predicted public health impacts.

Furthermore, FERC discloses that overall "[p]roject operation would have a permanent effect on air quality in the vicinity of the aboveground facilities associated with the Project,"⁴³⁷ while also recognizing in its Order that "measures could be implemented by the State of Alaska during the air permitting phase that would reduce these impacts."⁴³⁸

⁴³⁴ *Id.* at 412

⁴³⁵ FEIS at 4-975

⁴³⁶ PreTAR at 32-33.

⁴³⁷ *Id.*

⁴³⁸ FERC Order ¶ 209.

R. ADEC's Proposed Permit Fails to Include Enforceable Permit Conditions That Reflect the Ambient Air Boundary Modeling Assumptions

“AGDC used the proposed fenced perimeter around the Liquefaction plant as an ambient air quality boundary for the on-shore facility area ... excluded the marine vessel loading berths and trestle areas from ambient air assuming a 500-foot stand-off distance predicated upon reasonable and enforceable safety requirements.”⁴³⁹ ADEC’s proposal indicates that the “AAQS and increments only apply in ambient air locations, which has been defined by EPA as, ‘...that portion of the atmosphere, external to buildings, to which the general public has access.’”⁴⁴⁰ ADEC further explains that, “[a]pplicants may, therefore, exclude areas that they own or lease from their ambient demonstration if public access is “precluded by a fence or other physical barrier.”⁴⁴¹

ADEC suggests that “[t]he former element of AGDC’s approach offers a clear means to preclude the public from ambient air ... [t]he latter element of this approach, while not supported by explicit and quantifiable air quality guidance, is rooted in practical precedent.”⁴⁴² ADEC finally explains that

The Department’s discussion in the Ambient Boundary section of its Modeling Report for PacRim Coal, LLC’s Chuitna Project, Minor Permit AQ0957MSS03, offers relevant detail regarding the exclusion of vessel loading activities from ambient air. AGDC’s approach to exclude select areas from ambient air is appropriate for the Liquefaction plant ambient analysis.⁴⁴³

As an initial matter we point out that ADEC neither provided a reference to nor the documents where its prior discussion on Ambient Boundary could be found, thus we were unable to review that information. Furthermore, the proposed permit lacks requirements that AGDC effectively restrict access to the plant site. Therefore, ADEC “must impose requirements in the permit that would force” AGDC “to erect appropriate barriers or to take other measures that would effectively preclude public access.”⁴⁴⁴ Without such enforceable requirements it is unreasonable for ADEC to use the property boundary in modeling impacts and ADEC’s proposed decision essentially allows AGDC to emit more pollution, and possibly with fewer controls, than would otherwise be lawful.

Similarly, the proposed permit lacks any enforceable conditions covering the 500-foot stand-off distance for the marine loading berths and trestle areas, and without enforceable

⁴³⁹ PreTAR at 28.

⁴⁴⁰ PreTAR at 27, explaining that “[t]he term “ambient air” is defined in 40 CFR 50.1. The Alaska Legislature has also adopted the definition by reference in AS 46.14.90(2).”

⁴⁴¹ *Id.* at 29, explaining that “EPA has written a number of guidance documents regarding ambient air issues which may be found in their Modeling Clearinghouse Information Storage and Retrieval System (<http://cfpub.epa.gov/oarweb/MCHISRS/>). The documents routinely use the phrase “fence or other physical barrier” when discussing an acceptable means for precluding public access at onshore locations. The phrase originated in a December 19, 1980 letter from EPA Administrator Douglas Costle to Senator Jennings Randolph.”

⁴⁴² *Id.*

⁴⁴³ PreTAR at 27-28 (citation omitted).

⁴⁴⁴ *In the Matter of Hibbing Taconite Company*, 2 E.A.D. 838 (EAB 1989).

requirements we have the same concerns identified above. Therefore, ADEC's permit must include terms and conditions to ensure the source actually takes steps to preclude public access from these areas, that the plan be in writing and subject to ADEC's approval.⁴⁴⁵

VII. The Draft Permit's Terms and Conditions Are Insufficient to Ensure Compliance with the Clean Air Act

A. ADEC Allows for Use of Alternative Test Methods that are not EPA-approved

- Permit Condition 4.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:
 - d. *other methods and calculations approved by the Department*, including appropriate vendor-provided emissions factors when sufficient documentation is provided.⁴⁴⁶
- Permit Condition 35.7 Source testing for emissions of any contaminant may be determined *using an alternative method approved by the Department* in accordance with 40 C.F.R. 63 Appendix A, Method 301.⁴⁴⁷
- Permit Condition 36. Test Deadline Extension. The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is *approved in writing by the Department's* appropriate division director or designee.⁴⁴⁸

B. The proposed permit allows for amendments to the permit that the public will not have an opportunity to review and comment on

The following permit conditions allow siting of ambient monitors and development of a flare minimization plan, neither of which the public will have a chance to review and comment.

⁴⁴⁵ See, e.g., *In re Shell Gulf of Mexico, Inc.*, 15 E.A.D. 470, 510-514 (EAB 2020).

⁴⁴⁶ Draft permit at 3.

⁴⁴⁷ Draft permit at 32.

⁴⁴⁸ Draft permit at 32-33.

Moreover, the permit fails to provide that the flare minimization plan be submitted to the Department for approval.

10.2 Ambient Air Monitoring. The Permittee shall establish ambient PM-10 and PM-2.5 monitoring during the construction phase as follows: a. At least 180 days prior to commencing construction, submit for Department approval a scaled site map(s) that identifies the proposed locations of one or more downwind PM-10 monitoring site and one or more downwind PM-2.5 monitoring site.⁴⁴⁹ 4 Site the monitoring stations in areas that would likely experience the maximum construction-related 24-hour PM-10 and 24-hour PM-2.5 impacts from the Liquefaction plant project area. Include a written narrative that documents the reasons for selecting the proposed monitoring sites.⁴⁴⁹

17. Vent Gas Disposal (Flares) BACT Emission Limits: Limit the emissions from flares EUs 14 through 19 as specified in Table 7 and from EU 20 as specified in Table 8, which indicate that BACT control for these units is “*proper flare work practice requirements and establishing a flaring minimization plan.*”⁴⁵⁰

VIII. The Permit Is Unlawful Because ADEC’s Proposal Violated Public Participation and Federal Agency Consultation Requirements

A. ADEC Failed to Provide the Public Timely and Complete Access to the Supporting Record.

ADEC’s failure to comply with the public notice obligations are so substantial that it precludes public participation. Moreover, the limited information provided by ADEC is so defective that it rippled throughout its proposal, hampering the public’s participation and ability to review and identify issues. The harm from ADEC’s procedural violation is that it has deprived the public’s opportunity to have its views considered by ADEC. A key statutory objective of the Clean Air Act’s PSD program is to “assure that any decision to permit increased air pollution ... is made only after consideration of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process.”⁴⁵¹

Consistent with EPA’s regulations, to Alaska’s PSD regulations require ADEC to – among other things:

- (i) Make a preliminary determination whether construction should be approved, approved with conditions, or disapproved.

⁴⁴⁹ Draft permit at 8-9.

⁴⁵⁰ Draft permit at 23-24. (emphasis added)

⁴⁵¹ *In re Russel City Energy*, 14 E.A.D. 159, 175 (EAB 2008), citing *In re Rockgen Energy Center*, 8 E.A.D. 536, 557 (EAB 1999) (quoting CAA § 160(5), 42 U.S.C. § 7470(5)).

(ii) Make available in at least one location in each region in which the proposed source would be constructed a copy of *all materials the applicant submitted*, a copy of the preliminary determination, and *a copy or summary of other materials*, if any, *considered in making the preliminary determination*.⁴⁵²

Contrary to the requirement to make available *all materials the applicant submitted* and *a copy or summary of other materials*, if any, *considered in making the preliminary determination*, ADEC did not initially and, despite herculean efforts by NPCA, failed to provide these materials. The following is a summary of the timeline of NPCA's communications with ADEC to obtain and review the information submitted by the applicant and the materials ADEC considered in making its proposed determination to approval AGDC's PSD permit request.⁴⁵³

9/23/2020	Letter from NPCA to ADEC requesting a 30-day extension to the deadline for comments (from October 11 to November 10)
9/25/2020	Letter from NPCA requesting complete permit application, ⁴⁵⁴ correspondence between ADEC and AGDC, including attachments listed in the permit application. ADEC's supporting analysis, including electronic files for the proposed permit (e.g., modeling files, emission calculation spreadsheets, etc.) All correspondence to and from the FLMs regarding the plant, including notes of meetings and conference calls. ⁴⁵⁵
9/28/2020	Email from ADEC to NPCA indicating it will be granting the request to extend the comment period by 30 days.
9/28/2020	Email from ADEC to NPCA indicating it will need a public records request to move forward with the records requested on 9/25/2020. ⁴⁵⁶
9/29/2020	ADEC notification of extension of public comment period to 11/20/2020, with attachments.
10/29/2020	Letter from NPCA to ADEC requesting the remainder of the foundational materials, including analyses and supporting information in native format.

⁴⁵² 8 AAC 50.040 adopts by reference 40 C.F.R. § 51.166(q)(2) (emphasis added).

⁴⁵³ Copies of these communications are included as enclosures.

⁴⁵⁴ The initial information provided redacted AGDC's assertions regarding confidential business information, which were subsequently withdrawn. Notably, ADEC did not resolve these unsubstantiated claims prior to public notice, and thus shifted the burden to the public to identify and request that the claims be lifted.

⁴⁵⁵ Documents and emails between ADEC and external parties (permit applicant) and the FLMs/EPA/FERC, are not covered the deliberative process privilege since the incoming records are not ADEC's to protect, and for those that leave the agency, ADEC waives its right to protect. Therefore, it was unreasonable for ADEC to withhold these external communications, that it clearly "considered" in developing its proposed action. Further, we recognize some of these documents were initially covered by AGDC's CBI assertions, but those were subsequently waived after NPCA requested the AGDC BACT analysis.

⁴⁵⁶ Despite the PSD regulations requiring that the permitting agency provide the information it considered, ADEC required that NPCA submit a formal record request, which created a barrier to public participation.

- 10/29/2020 Email from NPCA, with addendum to NPCA's 10/29/2020 request, and confirmation from ADEC that it was received.
- 11/4/2020 Email and attached letter from ADEC to NPCA.^{457, 458}
- 11/6/2020 Email and attached documents from ADEC to NPCA and others, 2nd extension of public notice, until December 10, 2020.
- 11/10/2020 Letter from NPCA to ADEC requesting records and providing information that demonstrated the requester met the requirements for waiver of fees.⁴⁵⁹
- 11/10/2020 Email from ADEC to NPCA providing notification that an email and link would arrive to download the monitoring and modeling files
- 11/12/2020 Response to NPCA's letter of 10/29/20, where ADEC explained that a fee waiver was needed. The individual responding has not yet seen NPCA's 11/10/2020 letter
- 11/16/2020 Although NPCA's representative had signed ADEC's certification form, as explained in this letter, ADEC informed her that was not adequate and that she needed to submit a subsequent signed document using the language "I hereby certify," which was done via this letter. The letter further responded to ADEC's request for clarification regarding a portions of the requested information.
- 11/20/2020 Email from NPCA to ADEC inquiring as to whether any additional information needed for the fee waiver. Response from ADEC that the request for fee waiver was passed along to the Commissioner for

⁴⁵⁷ ADEC cover email explained that, "Requested Items 1 through 3: The Department has contacted the Alaska Gasline Development Corporation (AGDC) regarding your request and AGDC has since released all application materials previously submitted as confidential business information. The Department is currently working to get all of the application materials (requested items 1 and 3) as well as the Department's analyses in native MS Excel format (requested item 2) up on a new website. We will send you a link to this new webpage when it is live. The requested modeling files are too numerous and of too large a size to list on our webpage. Therefore, the Department will create a file transfer protocol (FTP) site for the requested modeling files and send you a link when it is live. Requested Items 4 and 5: The Department does not consider the consultation with the Federal Land Managers (FLMs) and communications with EPA to be a part of the material required for public notice. Therefore, please send the Department a Public Records Request for these materials and the Department will make a determination on whether this material will be released."

⁴⁵⁸ ADEC further explained that "Regarding the additional 60-day extension of the comment period: The Department has not made a decision on the request to grant an additional 60-day extension. As of this email the preliminary permit has already been out for public comment for over 50 days. However, the Department recognizes that additional time to review the requested items is appropriate before the public comment period ends. Therefore, an extension of a yet undecided timeframe will be granted prior to the current public comment period's closing date of November 10, 2020. We will notify you when a determination is made."

⁴⁵⁹ In addition to adding a requirement that the public submit a record request, ADEC insisted that NPCA pay fees for the information. While ADEC did not inform NPCA of the opportunity to submit a fee waiver request, NPCA's research identified this opportunity and submitted a fee waiver request.

consideration and there are no additional clarifications needed by the Department regarding the request.

- 12/2/2020 Letter from ADEC to NPCA indicating that the fee waiver was denied,⁴⁶⁰ this letter was transmitted at 1:05:01 AM MST.
- 12/2/2020 Email from ADEC to NPCA, transmitted at 1:20:09 AM, indicating that it was a request to “recall” the message sent earlier that morning.
- 12/3/2020 Letter from NPCA to ADEC including two requests, (1) copies of all electronic mail communications and attachments from the Federal Land Managers (FLMs) regarding the AK LNG Project as relates to the proposed PSD permit limited to time frame starting August 12, 2020 to present (December 3, 2020); and (2) extension of the public comment period until 1/11/2020 so that NPCA has time to review the communications from the FLMs.
- 12/4/2020 Email from ADEC to NPCA, which indicated the requested electronic communications from the Federal Land Managers would be transmitted via a link to download the files.
- 12/10/2020 Email from ADEC to NPCA explaining that the Department further considered NPCA’s request to extend the public comment period, which as explained in NPCA’s letter of December 3, 2020, NPCA sought to allow meaningful review of the incoming communications from the FLM. Those records were made available via download link on Friday, December 4, 2020 at 5:45 pm EST. Therefore, while we appreciate the documents for review, it is disappointing we were given three business days to review them before comments are due.

ADEC’s 74-day delay in providing the records documenting the PSD program’s requirement that it first consult with the FLMs prior to proposing the permit, had the result of NPCA having only three business days to review an incomplete set of documents.⁴⁶¹ The absence of information available in the administrative record, which despite NPCA’s efforts is still not available, prevented the public from being able to meaningfully understand and participate in the permitting process.

B. There is No Evidence to Show ADEC Provided the FLM’s with the Required 60-day Comment Period

⁴⁶⁰ ADEC’s letter failed to explain how NPCA could appeal this decision. Furthermore, NPCA does not waive any rights to appeal ADEC’s denial.

⁴⁶¹ NPCA first asked for the communications with the FLMs on September 25, 2020, and thus as seen in this timeline it was 74 days before a subset of the communications with the FLMs was provided.

The Clean Air Act and regulations require that written notice of a permit application and proposed PSD permit be provided to the Federal Land Manager (FLM) for a Class I area that may be affected by emissions from the proposed Liquefaction plant.⁴⁶² ADEC's SIP regulations require that it

[P]rovide written notice of any permit application for a proposed major stationary source or major modification, the emissions from which may affect a Class I area, to the Federal land manager and the Federal official charged with direct responsibility for management of any lands within any such area. Such notification shall include a copy of all information relevant to the permit application and shall be given within 30 days of receipt and at least 60 days prior to any public hearing on the application for a permit to construct. Such notification shall include an analysis of the proposed source's anticipated impacts on visibility in the Federal Class I area.⁴⁶³

State permitting agency requirements to consult with the Federal Land Managers regarding impacts to Class I areas are an important part of the PSD permitting regulations because the FLMs are "charged with direct responsibility for management of such lands have an affirmative responsibility to protect the air quality related values (including visibility) of such lands and to consider" in consultation with the permitting agency, "whether a proposed source or modification will have an adverse impact on such values."⁴⁶⁴ ADEC's PreTAR explains that the Department initially "notified the FWS and the NPS of the pending PSD application on 12 October, 2017. The FWS responded the same day by saying they would like to kept informed and that they wanted to discuss the AQRV evaluation. The NPS expressed their interest during a 24 October, 2017 teleconference with the FLMs."⁴⁶⁵ There is no other information in the PreTAR regarding ADEC's consultation with the FLMs. Furthermore, the PSD program requires that EPA consult with ADEC along with the FLMs regarding the FLM concerns. There is nothing in the record to show this occurred.⁴⁶⁶

In light of the special role and authority provided the FLMs and the lack of information about ADEC's consultation with the FLMs, as seen in the enclosures to these comments, NPCA requested information on the consultation for this proposed permit. As the enclosures show, NPCA tried over a period of months to obtain information on the communications that occurred between ADEC and the FLMs, and it was not until three business days before the comments were due that ADEC finally shared a portion of those records.

⁴⁶² CAA § 165(d)(2)(A); 40 C.F.R. § 52.21(p) (Sources Impacting Federal Class I Areas)(2011).

⁴⁶³ 8 AAC 50.040(h)(14) ADEC adopts by reference, 40 C.F.R. § 52.21(p). Moreover, "[i]rrespective of distance from a proposed source to the Class I area, permit applicants are legally obligated to demonstrate that their proposed facilities will not cause or contribute to air pollution in violation of any PSD increment, including the Class I increments. CAA § 165(a)(3)(A), 42 U.S.C. § 7475(a)(3)(A); 40 C.F.R. § 52.21(k)(2)." *NMU* at 329.

⁴⁶⁴ *Id.*

⁴⁶⁵ PreTAR at 3. The PreTAR includes citations to emails, but those emails were not included as part of the proposed permit action. (Email from James Renovatio (Department) to Andrea Stacy (NPS) and Catherine Collins (FWS), *Alaska LNG – Liquefaction Class I impacts for proposed PSD permitting*; 12 October, 2017; Email from Catherine Collins (FWS) to James Renovatio and Alan Schuler (Department), *Re: Alaska LNG – Liquefaction Class I impacts for proposed PSD permitting*; 12 October, 2017.) *Id.*

⁴⁶⁶ Although several of the emails NPCA obtained through its records request to ADEC reveal that EPA was included in emails regarding the FLMs concerns about not receiving prior notice of the Liquefaction Plant, EPA was not involved in the subsequent communication emails between ADEC and FLMs where the proposed permit for the Liquefaction plant was discussed.

Moreover, under the regulations, ADEC is required to “consider any analysis performed by the Federal land manager ... that shows that a proposed new major stationary source ... may have an adverse impact on visibility in any Federal Class I area.” Additionally, where ADEC “finds that such an analysis does not demonstrate to the satisfaction of the ... [ADEC] that an adverse impact on visibility will result in the Federal Class I area, the ... [ADEC] must, in the notice of public hearing on the permit application, either explain his decision or give notice as to where the explanation can be obtained.”⁴⁶⁷ There is nothing in the information for the proposed permit to demonstrate that ADEC considered analysis from the FLMs, nor did ADEC’s notice explain that it did not agree with the FLMs or give notice where ADEC’s explanation can be obtained.

Additionally, ADEC’s PSD regulations provide the following, and there is nothing in the proposed permit record to indicate whether ADEC received such a demonstration, or whether ADEC concurs:

Federal Land Manager of any such lands may demonstrate to the ... [ADEC] that the emissions from a proposed source or modification would have an adverse impact on the air quality-related values (including visibility) of those lands, notwithstanding that the change in air quality resulting from emissions from such source or modification would not cause or contribute to concentrations which would exceed the maximum allowable increases for a Class I area. If the ... [ADEC] concurs with such demonstration, then he shall not issue the permit.⁴⁶⁸

The PSD regulations require that ADEC’s public participation for the proposed permit action make available the following:

[A] copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy or summary of other materials, if any, considered in making the preliminary determination.⁴⁶⁹

The information regarding ADEC’s notification to the FLMs regarding the permit application and proposed permit was not provided to the public as part of the proposed permit notice, nor was there a copy of materials that ADEC received from the FLMs. Therefore, in order to confirm the FLMs received the necessary notifications and review comments and materials sent by the FLMs to ADEC, as explained above, over a period of 74 days, NPCA submitted written requests, fee waiver documentation, certifications and clarification to ADEC to obtain this information.

ADEC provided the electronic communications from the FLMs to NPCA on December 7, 2020.⁴⁷⁰ NPCA’s review of the communications found that the FLMs had not been provided the notifications and opportunity to comment required by the PSD regulations. Instead, in addition to submitting significant concerns and details about the proposed permit, the FLMs expressed considerable concern about ADEC’s timing and efforts.

⁴⁶⁷ *Id.*

⁴⁶⁸ 40 C.F.R. § 52.21(p)(4).

⁴⁶⁹ 40 C.F.R. § 51.166(q)(2)(ii).

⁴⁷⁰ A compilation of these emails enclosed.

C. There is No Evidence Demonstrating ADEC Provided Notice and Communicated with EPA

ADEC is also required to provide notice to EPA in its implementation of the PSD program. This notice consists of a copy of the permit application for sources subject to PSD and notice of every action related to the consideration of the permit.⁴⁷¹ ADEC's proposed permit information also failed to include this information. Therefore, NPCA requested information from the State regarding "[a]ll ADEC records regarding communication with EPA in its oversight role of this proposed permit,"⁴⁷² and despite the fact that the PSD regulations required this communication and that EPA generally provides comments on proposed PSD permits in its oversight role, as discussed above, NPCA was informed a written records request and agreement to pay fees were required before ADEC would release the communications. Thus, NPCA never received this information and was unable to determine whether the required notifications were provided and whether EPA expressed any concerns with either the permit application or ADEC's proposal to approve the permit.

CONCLUSION

In short, ADEC cannot validly finalize the proposed permit. To issue the permit as proposed would not only be unlawful under Alaska's SIP, but contrary to the Congressional purposes of the PSD program to:

- Protect health and welfare;
- Preserve and protect the air quality in Alaska's national parks and preserves, and national wilderness areas;
- Insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources; and
- Assure that any decision to permit increased air pollution is made only after careful evaluation of all the consequences of such a decision.

Therefore, ADEC must either deny the request for construction and withdraw its proposed permit approval, or require AGDC submit a full and complete application addressing the myriad defects providing all required analysis and documentation. Should ADEC repropose a valid permit, it must disclose all of the underlying information to the public.

⁴⁷¹ These regulatory requirements are often memorialized between state permitting agencies and EPA regional offices in what's called a "Performance Partnership Agreement" ("PPA") that provides the details on communications like CAA permits.

⁴⁷² NPCA Letter to ADEC at 2 (Oct. 29, 2020).

List of Enclosures

Comments Submitted on Behalf of National Parks Conservation Association Center for Biological Diversity Northern Alaska Environmental Center

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Name
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 10.26.2020 ARD_AKLNG_LNG-LF_Compression_turbines_Revised-vendor-TCI_Revised-electricity_costs-revised-inlet-temp.xlsm
 10.26.2020 ARD_AKLNG_LNG-LF_Compression_turbines_TCI_default_Revised-electricity_costs-NOtemp.xlsm
 10.26.2020 ARD_AKLNG_LNG-LF_PG_turbines_Revised-vendor-TCI_revised-electricity_costs-inlet-temp.xlsm
 10.26.2020 ARD_AKLNG_LNG-LF_PG_turbines_TCI_default_revised-electricity_costs-inlet-temp.xlsm
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- Appendix U: ANILCA Section 810 Final Evaluation, PDF.
- Appendix V: Health Impact Assessment, PDF.
- Appendix W: Past, Present, and Reasonably Foreseeable Future, PDF.
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Exhibits 1-29 of Stamper Report:

Exhibit # to Stamper Report	Description
1	Fact Sheet for GE LMS100 Gas Turbine
2	Fact Sheet for GE 9E>13E2 Power Plants
3	Final Air Permit No. 1010524-001-AC (PSD-FL-444), Shady Hills Combined Cycle Facility
4	June 24, 2019 PSD Permit and Permit to Construct Balico LLC/Chickahominy Power, issued by Virginia Department of Environmental Quality
5	January 9, 2019, Registration Number 21599, Atlantic Coast Pipeline, LLC, issued by Virginia Department of Environmental Quality
6	NSR Permit No. 0761-M10, Williams Four Corners LLC, Thompson Compressor Station, Issued by New Mexico Environment Department
7	GE LM6000 Power Plants Fact Sheet
8	BASF NOxCat VNX SCR Fact Sheet
9	BASF NOxCat ZNX Fact Sheet
10	May 25, 2018 Permit Application for Atlantic Coast Pipeline LLC, Buckingham Compressor Station
11	Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, Power, 2011
12	Bay Area Air Quality Management District, Preliminary Determination of Compliance, Mariposa Energy Project, August 2010
13	Draft Permit for Dominion Energy Cove Point – Charles Station
14	Air Permit No. 10466R00, issued February 27, 2018, Northampton Compressor Station
15	Permit No. R13-3271, issued July 21, 2016, for Marts Compressor Station
16	SCR Cost Calculation Spreadsheet for Alaska LNG Compressor Turbines at 2.0 ppm Controlled NOx Rate

17	SCR Cost Calculation Spreadsheet for Alaska LNG Compressor Turbines at 3.5 ppm Controlled NOx Rate
18	SCR Cost Calculation Spreadsheet for Alaska LNG Power Turbines
19	Preliminary ADEC Technical Analysis Report for Construction Permit AQ0083CPT07 issued to Agrium U.S., Inc., for the Kenai Nitrogen Operations, November 20, 2020
20	EPA, PRO Fact Sheet No. 103 Install Electric Compressors
21	Armendariz, Al, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements, prepared for Environmental Defense Fund, January 26, 2009
22	Spreadsheet entitled “Alaska LNG GHG Turbine Analysis Revised”
23	GE, VOC Emissions from LM6000 for Mariposa Energy, LLC
24	GE, Advantages of Aeroderivatives Infographic
25	Palmdale Energy PSD Permit
26	EPA, Air Pollution Control Fact Sheet, Flare, EPA-452/F-03-019
27	Shah, Tejas, Ramboll Environ (EPA Contractor), Greg Yarwood (Ramboll Environ), Alison Eyth (EPA), and Madeleine Strum (EPA), Composition of Organic Gas Emissions from Flaring Natural Gas, August 18, 2017
28	EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022
29	EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000

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