# 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

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The following provides review and comments on the Alaska Department of Environmental Conservation's (ADEC's) proposed emission limits in its draft air quality control construction permit (Permit AQ1539CPT01) ("Draft Permit") for the Alaska Gasline Development Corporation's (AGDC's) planned liquefied natural gas plant ("Alaska LNG Plant").[1] This permit is classified as a Prevention of Significant Deterioration (PSD) permit.

The PSD permit for AGDC's proposed Alaska LNG plant must impose emission limits reflective of best available control technology (BACT) for each regulated air pollutant that the facility has the potential to emit in significant amounts,[2] which include nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), sulfur dioxide ($SO_2$), particulate matter (PM) including $PM_{10}$ and $PM_{2.5}$, and greenhouse gases (GHG).[3] Best available control technology is defined as follows:

> an 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 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).

This report provides comments on ADEC's BACT analyses and its proposed BACT emission limits and other associated requirements in the Draft Permit for the Alaska LNG plant.

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[1] These comments were prepared by Victoria Stamper, Boise, ID. Ms. Stamper is an independent air quality consultant and engineer with extensive experience in new source review permitting. Ms. Stamper's Curriculum Vitae is included at Attachment A.

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

[3] ADEC's Preliminary September 11, 2020 Technical Analysis Report (TAR) at 2.

# I. Comments on the BACT Analysis for the Compressor Turbines and the Power Turbines

The AGDC's proposed Liquified Natural Gas Plant will have several natural gas-fired turbines. Six simple cycle gas turbines will be used for gas compression (two for each LNG line). Three combined cycle gas turbines will be used for power generation. However, 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."[4] Yet, knowing the turbine make and model is important to be able to accurately project potential emissions, understand flue gas exhaust characteristics, and analyze and set BACT emission limits. In fact, EPA's New Source Review 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."[5] For natural gas-fired turbines, identification of the make and model of the turbine is relevant to the BACT analysis for NOx, CO, VOCs, GHG, and other pollutants, as well as potential to emit of the turbines. For example, two potential turbine options for the large compressor turbines envisioned by the AGDC permit application are the GE LMS100 aeroderivative gas turbine and the GE Model 9E.03 turbine. The GE LMS100 turbine has a baseline NOx rate of 25 ppm@ 15% $O_2$.[6] The GE Model 9E.03 turbine has a dry low NOx combustor NOx rate of 5 ppm (assuming the ultra-low NOx option is chosen).[7] Those are very different levels of NOx emission rates. The net heat rate can also vary between turbine models, which can impact the GHG BACT determination. For example, the lowest heat rate of the GE LMS 100 model turbine is 7,718 British Thermal Unit per kilowatt hour (Btu/kWh) (net), and the heat rate of the GE 9E.03 turbine is 9,860 Btu/kWh (net).[8] The GE 9E.03 turbine is clearly much less efficient, which could significantly impact GHG emissions.

The make and model of the gas turbines is typically specified in an air permit in the descriptions of the emission units to be constructed. Moreover, the capacity of the turbines is 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. For example, an air permit for a new combined cycle power generating unit at the Shady Hills Power plant in Florida identifies the emissions unit as a 385 MW GE 7HA.02 Combustion Turbine, with one heater recovery steam generator with duct firing of 210 MMBtu/hr, and a 210 megawatt (MW) steam turbine generator.[9] An air permit for the Chickahominy power station in Virginia identified the turbines as Mitsubishi Hitachi Power

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[4] *Id.* at 2 and 19.

[5] EPA. October 1990, New Source Review Workshop Manual, at H.5.

[6] *See* https://www.ge.com/power/gas/gas-turbines/lms100.

[7] *See* https://www.ge.com/power/gas/gas-turbines/9e-03.

[8] *See* Fact Sheets for GE LMS100 Gas Turbines and GE 9E&GT13E2 Power Plants, attached as Exhibits 1 and 2.

[9] Final Air Permit No. 1010524-001-AC (PSD-FL-444), Shady Hills Combined Cycle Facility, issued by Florida Department of Environmental Protection, at 7, attached as Ex. 3.

Systems (MHPS) M501JAC combustor turbines with a rated heat input capacity of 4,070 MMBtu/hr heat and Mitsubishi heat recovery steam generators with steam turbine generators of 178 MW generating capacity.[10] An air permit for the Buckingham Compressor Station to be located in Virginia identified the turbines as four different specific models of Solar turbines and listed the rated capacity of each turbine in terms of horsepower (hp).[11] A new source review air permit issued for the Thompson Compressor Station in New Mexico identified the turbines by make, model, serial number, and horsepower.[12] These are just a few examples of permits that specifically identify the make and model and also power (horsepower or megawatt rating) of turbines to be installed.

The Draft Permit for the Alaska LNG plant identifies the compressor turbines only by heat input in MMBtu/hr and also only identifies the combined cycle power generation turbines by heat input in MMBtu/hr.[13] The permit application form includes a table that identifies the nominal kilowatt capacity of the turbines, although it does not make clear the horsepower rating for the compressor turbines nor does it make clear whether the stated kW capacity of the power generating turbines is for the turbine alone or the units in combined cycle mode.[14] As stated above, the ADEC's Technical Analysis Report states that the turbine make and model are yet to be selected, so even these assumed hourly heat inputs appear to be estimates at this time. ADEC must require more specificity from AGDC on the turbines to be installed, including make and model, horsepower or megawatt rating, as well as hourly heat input, and include those details in the list of permitted equipment. In addition, for the combined cycle units, the MW rating of the heat recovery steam turbine generator 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. Without knowing the specific make and model of turbines, it is very difficult to evaluate BACT and set BACT emission limits, particularly for NOx, CO, and GHG. Thus, it is imperative that ADEC obtain more details on the turbines and specify those details in the list of permitted equipment. Further, ADEC must take into account the turbine make and model and associated emission specifications in determining BACT and take into account specific flue gas characteristics of the turbines in the air dispersion modeling.

## A. NOx BACT For Compressor Turbines (EU 1-6) and Power Turbines (EU 7-10)

The LNG plant will use six simple cycle natural gas-fired combustion turbines (EU 1-6) for the three compressor LNG trains at the facility, with two turbines used for each LNG train.[15] The LNG plant will use four natural gas-fired combustion turbines operated in a combined cycle mode for power

[10] June 24, 2019 PSD Permit and Permit to Construct Balico LLC/Chickahominy Power, issued by Virginia Department of Environmental Quality, at 2, available at https://www.deq.virginia.gov/Programs/Air/ChickahominyPowerStation.aspx#IssuedPermits and attached as Ex. 4.
[11] January 9, 2019, Registration Number 21599, Atlantic Coast Pipeline, LLC, issued by Virginia Department of Environmental Quality, at 5, attached as Ex. 5.
[12] NSR Permit No. 0761-M10, Williams Four Corners LLC, Thompson Compressor Station, issued by New Mexico Environment Department, at A5, attached as Ex. 6.
[13] September 11, 2020 Draft Construction Permit AQ1539CPT101 for Alaska Gasline Development Corporation Liquefaction Plant (hereinafter referred to as "Draft Permit") at 1.
[14] *See* Attachments 4 and 5 of 2018 Alaska LNG Permit Application, at pdf page 371 (Table EC-4).
[15] ADEC's September 11, 2020 TAR, Appendix B at 2.

generation (EU 7-10).[16] 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 or ppmvd @ 15% $O_2$) as BACT for NOx at all of these turbines.[17] ADEC rejected the NOx control of DLN combustors along with selective catalytic reduction (SCR) to meet a NOx limit of 2 ppmv@ 15% $O_2$ as not cost effective, despite acknowledging that several similar turbines have installed such controls as BACT. There are several flaws with the ADEC BACT analyses, as discussed in the following comments.

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

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. ADEC assumed a NOx baseline emission rate of 15 ppmv@ 15% $O_2$ for both the compressor turbines and the power generating turbines in evaluating the cost effectiveness of additional NOx controls.[18] In deciding to use a 15 ppmv NOx baseline for all of the turbines, ADEC claimed it followed the same approach that AGDC assumed – i.e., that the DLN combustors are "an inherent design feature of new gas-fired combustion turbines and is therefore considered baseline for determining cost effectiveness."[19] However, AGDC stated that a higher 25 ppmv@ 15% $O_2$ NOx rate reflected the baseline NOx emissions with DLN technology for the compressor turbines.[20] AGDC further stated that it evaluated use of ultra-dry low NOx (UDLN) combustors to meet a NOx rate of 9 ppmv@ 15% $O_2$ for the compressor turbines.[21] Thus, there was no basis in the permit application for ADEC's baseline emissions assumption for NOx of 15 ppmv@ 15% $O_2$ for the compressor turbines.

ADEC stated that it considered the planned DLN combustors at a NOx rate of 15 ppmv as inherent to the design of new natural gas-fired turbines.[22] Yet, the company, AGDC, stated that a 25 ppmv NOx rate was a "base-case offering from the turbine vendor."[23] In addition, AGDC and ADEC have proposed a NOx BACT emission limit for the compressor turbines of 9 ppmv@ 15% $O_2$ based on the use of DLN combustors,[24] and thus the 15 ppmv NOx baseline used by ADEC does not even comport with the NOx limit reflective of DLN combustors that AGDC proposed to meet.[25] Moreover, given that the turbine make and model is currently not known or required by the permit, there is no justification for making

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[16] *Id.* at 19.
[17] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 6 and 24.
[18] *Id.* at 7 and at 23.
[19] *Id.*
[20] *See* Attachment 6 to AGDC Liquefaction Plant Permit Application, Liquefaction Plant BACT Analysis, April 30, 2018, at 21
[21] *Id*.
[22] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 7.
[23] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 21-22.
[24] *Id.* at 21; *see also* Draft Permit at 13.
[25] In a spreadsheet entitled "12_Trade Secret_cost effectiveness_Compression Turbines" that was made available to the National Parks Conservation Association in November of 2020, a 25 ppmv NOx emission rate was considered baseline for the compressor turbines and a 9 ppmv NOx rate was considered as reflective of UDLN (i.e., ultra-dry low NOx combustors). See tab entitled "Compression UDLN" at rows 100 and 110 of the a spreadsheet entitled "12_Trade Secret_cost effectiveness_Compression Turbines." AGDC cites to "AKLNG Compression turbine – Supporting Data (USAL-CB-SRZZZ-00-000005-500)" as the reference for this data.

any assumptions about the base case NOx emission rate. As discussed at the beginning of this report, the make and model of the turbine defines the NOx emission rate that is considered inherent to the design of the turbine with DLN combustors, and the NOx rate can vary significantly between turbine models and vendors.

For the power generating turbines, both AGDC and ADEC relied on the same base case NOx emission rate of 15 ppmv NOx rate.[26] However, 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, this assumed baseline NOx rate is unjustified. As an example, one GE turbine of similar size to the planned 40,000-45,000 kW size of the power turbines[27] is the GE LM6000. This turbine has a baseline NOx rate of 25 ppmv but an upgrade to "DLE" technology is available that would allow the turbine to meet a NOx rate of 15 ppmv.[28] Thus, without a turbine make and model specified in the permit, ADEC does not have a valid basis for assuming a 15 ppmv NOx baseline rate in determining cost effectiveness of NOx controls.

AGDC's use of a 25 ppmv@ 15% $O_2$ 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% $O_2$ NOx baseline. This report has given two examples of combustion turbines the approximate size of the proposed compressor turbines and of the power turbines with a NOx rate with DLN combustions of 25 ppmv@15% $O_2$: 1) the GE LMS100 turbine, a 117,000 kW net output turbine with a baseline NOx rate of 25 ppm@ 15% $O_2$,[29] and 2) the GE LM6000, a turbine in the range of 45,000 – 57,000 kW with a NOx emission rate of 25 ppmv@15% $O_2$.[30] There are likely several other examples of gas turbines with 25 ppmv NOx emission rates with DLN combustors, as there are several turbine vendors and models aside from these two GE models.

For all the above reasons, ADEC's choice of NOx baseline emissions for the compressor turbines is deficient. The baseline for NOx emissions should be based on a NOx rate of 25 ppmv@ 15% $O_2$, as reflective of the NOx rate of a new natural gas-fired turbine with dry low NOx combustors. Given that the Draft Permit has not specified a certain turbine make and model and that AGDC has not proposed a turbine make and model, it is reasonable to assume a NOx baseline of 25 ppmv@ 15% $O_2$.

To convert this NOx rate to a ton per year baseline, a formula provided in EPA's 1993 Alternative Control Techniques for Stationary Gas Turbines was used to convert the 25 ppmv@ 15% $O_2$ NOx baseline rate to 0.100 lb/MMBtu.[31] For the compressor turbines, this baseline NOx rate of 0.100 lb/MMBtu was

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[26] *Id.* at 38.
[27] *See* AGDC 2018 Permit Application, Attachments 4&5 at pdf page 371 (Table EC-4).
[28] *See* https://www.ge.com/power/services/gas-turbines/upgrades/lm6000-sac-to-dle-conversion. *See also* GE LM6000 Power Plants Fact Sheet, attached as Ex. 7.
[29] *See* https://www.ge.com/power/gas/gas-turbines/lms100. *See also* Fact Sheet for GE LMS100 Gas Turbine, attached as Ex. 1.
[30] *See* https://www.ge.com/power/gas/gas-turbines/lm6000#product-spec-main. *See also* GE LM6000 Power Plants Fact Sheet, attached as Ex. 7.
[31] *See* EPA's January 1993 Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (EPA-453/R-93-007) at Appendix A for explanation of formula to convert from ppmv@ 15% $O_2$ to lb/MMBtu, available at https://www.epa.gov/ground-level-ozone-pollution/control-techniques-guidelines-and-alternative-control-techniques.

multiplied this rate by the 1,113 MMBtu/hour maximum heat input capacity specified in the Draft Permit[32] and an assumed 8,760 hours per year of operation (given that no operational limits have been proposed for these turbines), for an annual baseline NOx rate of 487.5 tons per year (tpy). This is a bit higher than assumed by AGDC and is much higher than the ADEC's assumed NOx baseline of 281.8 tpy. For the power generating turbines, the 0.100 lb/MMBtu baseline rate was multiplied by the 384 MMBtu/hr heat input capacity specified in the Draft Permit and an assumed 8,760 hours per year to arrive at an annual NOx baseline rate of 168.2 tons per year. This also is much higher than the 104 tpy NOx baseline assumed by ADEC for the power turbines.

### 2. AGDC Assumed Too High of an Interest Rate and Too Short of 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 is cost effectiveness analysis of SCR and DLN combustors for the compressor turbines and the power turbines.[33] 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."[34] 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.[35] 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 for the power turbines.[36] EPA's SCR Cost Spreadsheets that it has made available with its recent updates to its Control Cost Manual[37] recommend using the current bank prime lending rate in amortizing capital costs of controls, and it is currently 3.25%.[38] EPA's SCR Control Cost Manual also indicates that an SCR at an industrial boiler should have a useful life of 20-30 years.[39] However, for a power plant, EPA states that an SCR should have a useful life of 30 years or more.[40]

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 also 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

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32 Draft Permit at 1.
33 ADEC's Preliminary September 11, 2020 TAR, Appendix B at 6 and at 23.
34 *See* cover page for Appendix B to Attachment 6, BACT Analysis, April 30, 2018 of AGDC's Alaska LNG Application.
35 ADEC's Preliminary September 11, 2020 TAR, Appendix B at 6 and at 23.
36 *Id.* at 7 and 24.
37 *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.
38 *See* https://www.federalreserve.gov/releases/h15/.
39 *See* EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 80.
40 *Id.*

are expected to have a 30-year life).[41] 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.[42] EPA states that SCR at a power plant 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, instead of the 25-year life assumed by ADEC.

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 should be using in its BACT cost effectiveness calculations as it is the most up-to-date with current costs for SCR.

### 3. 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." Yet, 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.[43] 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. In addition, with the recently announced construction permit for the nearby Agrium facility which will produce ammonia and urea for sale, the costs for AGDC to obtain ammonia or urea reagent for SCR operation should be very reasonable because there would be little to no transportation costs.

In addition, 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. 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 ratio of 3 to 1.[44] Aqueous ammonia has the highest operating costs because of the cost of transportation.[45] 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.[46] Although EPA's SCR cost calculation spreadsheet made available with the revised 2019 SCR chapter of the Control Cost Manual does not

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[41] *See* April 14, 2017 Resource Report No. 1 General Project Description at 1-92, at pdf page 180 of Attachments 1 through 3 of 2018 Alaska LNG Permit Application.
[42] *See* 2018 Alaska LNG Application Attachments 4 and 5 at pdf page 229.
[43] *See* EPA Control Cost Manual, Chapter 2, Selective Catalytic Reduction, June 2019, at pdf page 82.
[44] *Id*. at pdf page 5.
[45] *Id.*
[46] U.S. Geological Survey, Minerals Commodities Summaries 2020, at 116, available at https://www.usgs.gov/centers/nmic/mineral-commodity-summaries.

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.

### 4. AGDC and ADEC Assumed Too High of a Cost for Electricity, Given that the Alaska LNG Facility Will Be Equipped with Power Generating Turbines.

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.[47] However, the Alaska LNG facility will have its own power generators and thus could generate the power needed for operation of the SCR systems. 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."[48] 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.[49] Thus, AGDC and ADEC should use the actual cost for generation of auxiliary power at its Alaska LNG 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, the EPA default cost of $0.0361/kWh should be used.

### 5. Revised Cost Effectiveness Calculations for NOx Controls at the Alaska LNG Compressor Turbines and Power Turbines

To address the deficiencies discussed above, I 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.[50] For these calculations, I used the following inputs:

[47] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 7 and at 23.
[48] 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.
[49] *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.
[50] *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. While this spreadsheet was not identified to be used with natural gas-fired combustion turbines, as EPA states that its use is for boilers fired by coal, fuel oil, or natural gas with heat input greater than 250 MMBtu/hr or generating capacity greater than or equal to 25 MW, the spreadsheet can be used to estimate SCR capital and operations costs for any fossil fuel-fired unit as long as the necessary input data is available. In fact, it has been utilized by several oil and gas facilities in regional haze control analyses, such as in New Mexico.

**Table 1. Inputs to EPA's SCR Cost Spreadsheet for Alaska LNG Compressor Turbines and the Power Turbines**

| Input to SCR Spreadsheet | Value for Compressor Turbines | Value for Power Turbines |
|---|---|---|
| Maximum heat input rate | 1113 MMBtu/hr | 384 MMBtu/hr |
| Higher heating value of fuel | 1,087 Btu/standard cubic feet (scf) | 1,087 Btu/scf |
| Estimated annual fuel consumption (based on 8,760 hours per year of operation) | 8,969,530,819 scf/year | 3,094,609,016 scf/year |
| Net plant heat rate (default for natural gas) | 8.2 MMBtu/MW | 8.2 MMBtu/MW |
| SCR equipment life | 25 years | 30 years |
| Interest rate | 3.25% | 3.25% |
| Reagent type | 99.5% anhydrous ammonia | 99.5% anhydrous ammonia |
| Reagent density | 38.2 lb/ft$^3$ | 38.2 lb/ft$^3$ |
| Reagent cost | $230/ton | $230/ton |
| Electricity cost | $0.0361/kWh | $0.0361/kW |

These cost calculations assume that the SCR 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, a level of NOx control that SCR systems can readily achieve. For example, BASF makes several SCR catalysts that it claims can achieve up to 97% NOx reduction.[51] The NOxCat™ ETZ catalyst is specifically designed for simple-cycle power generating turbines and other high temperature turbine applications.[52] The NOxCat™ VNX and ZNX catalysts can achieve up to 99% NOx reduction and are most effective at a temperature range of 550 to 800 degrees Fahrenheit.[53] A related catalyst called NOxCat™ VNX-HT is designed for use in aeroderivative simple-cycle turbines that can achieve 99% NOx removal and can reach optimal performance at turbine exhaust temperatures 800 to 850 degrees Fahrenheit.[54] While AGDC states that the compressor turbines "are anticipated to exhaust at a temperature of approximately 1000 [degrees Fahrenheit],"[55] the actual exhaust temperature is unknown because AGDC has not specified a make or model of compressor turbine to be installed. Moreover, if necessary to optimize NOx removal across the SCR, there are options to use to reduce the temperature of the exhaust gas before it enters the SCR. For example, the Buckingham Compressor Station which was proposed to be constructed in Virginia would be equipped with Solar turbines with SoLoNOx, SCR, and cooling air skids.[56] Essentially, the cooling air skids provide for the injection of tempering air at the turbine discharge (upstream of the SCR)

[51] *See* BASF, SCR Catalysts for Power Generation, at https://catalysts.basf.com/products-and-industries/stationary-emissions/solutions-for-power-generation/scr-catalysts-for-power-generation.

[52] *See* BASF, NOxCat ETZ, available at https://products.basf.com/global/en/cc/noxcat-etz.html.

[53] *See* BASF, Fact Sheets for NOxCat™ VNX & and NOxCat™ ZNX for Power Generation, available at https://catalysts.basf.com/literature-library/stationary-emissions-catalysts/solutions-for-industrial-engines, and attached as Exs. 8 and 9.

[54] *Id.*

[55] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 18.

[56] *See* May 25, 2018 Permit Application for Atlantic Coast Pipeline LLC, Buckingham Compressor Station, at pdf page 129 (Design Summary), attached as Ex. 10.

to cool the exhaust temperature to the optimal temperature of the SCR catalyst.[57] Thus, there are readily implementable options to address high exhaust temperatures and to optimize the NOx removal efficiency of an SCR system at a simple cycle gas turbine. For the power turbines that will operate in combined cycle mode, the temperature of the exhaust will be reduced before entering the SCR due to the heat recovery steam generator, and thus there should be no concern that the exhaust temperature may be too high for optimal NOx removal across the SCR. Indeed, AGDC did not raise any issues with the exhaust gas temperature being too high for optimal operation of an SCR at the power turbines.

In its BACT discussion for the compressor turbines, AGDC indicates 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."[58] However, SCR has been required as BACT and installed on numerous simple cycle gas turbines that operate as peaking plants in the United States with varying load ranges. For some permits for simple cycle turbines, 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). For example, in a permit analysis for the Mariposa Energy Project to be located in Alameda County, California, the Bay Area Air Quality Management District (BAAQMD) provided numerous examples of simple-cycle gas turbines permitted in the District with 1-hour average NOx limits of 2.5 ppmvd @ 15% $O_2$ and required the new simple-cycle gas turbines of the Mariposa Energy Project to meet a NOx BACT limit of 2.5 ppmvd.[59] These BACT determinations can also be found in the California Air Resources Board (CARB) BACT Clearinghouse.[60] Those example simple-cycle turbine NOx limits with SCR are given in Table 2 below.

**Table 2. Simple-Cycle Turbines in California with NOx Limits with SCR of 2.5 ppmvd@15%$O_2$[61]**

| Facility | NOx Limit Averaging Time |
|---|---|
| Panoche Energy Center | 1-hour avg |
| Walnut Creek Energy Park | 1-hour avg |
| Sun Valley Energy Project | 1-hour avg |
| CPV Sentinel Energy Project | 1-hour avg |
| Lambie Energy Center | 1-hour avg |
| Riverview Energy Center | 1-hour avg |

[57] *See* e.g., Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, available at https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/ and attached as Ex. 11.

[58] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 18.

[59] *See* Bay Area Air Quality Management District, Preliminary Determination of Compliance, Mariposa Energy Project, August 2010, at 38-39, available at http://www.energy.ca.gov/sitingcases/mariposa/documents/others/2010-08-18_Preliminary_Determination_of_Compliance.pdf, and also attached as Ex. 12.

[60] https://www.arb.ca.gov/bact/bactnew/rptpara.htm.

[61] *Id.* at 38.

| | |
|---|---|
| Wolfskill Energy Center | 1-hour avg |
| Goosehaven Energy Center | 1-hour avg |

Further, a review of the EPA's RACT/BACT/LAER Clearinghouse shows numerous other simple-cycle combustion turbines with NOx BACT limits of 2.5 ppmvd, as shown in the table below.

**Table 3. Simple-Cycle Turbines in EPA's RACT/BACT/LAER Clearinghouse with NOx Limits with SCR of 2.5 ppmvd@15%$O_2$**

| Facility | RBLC ID Number[62] | NOx Limit Averaging Time |
|---|---|---|
| Bayonne Energy Center LLC | NJ-0086 | 3-hour avg |
| Troutdale Energy Center | OR-0050 | 3-hour avg |
| Vineland Municipal Electric Utility | NJ-0077 | 3-hour avg |
| Bayonne Energy Center LLC | NJ-0075 | Not given |
| PSEG Fossil LLC Kearny Generating Station | NJ-0076 | 3-hour rolling avg |
| El Cajon Energy LLC | CA-1174 | 1-hour avg |
| Orange Grove Project | CA-1176 | 1-hour avg |
| Escondido Energy Center LLC | CA-1175 | 1-hour avg |

In addition to SCR being required and utilized to meet BACT at simple cycle peaking turbines, which often have widely variable load fluctuations, SCR has also been required as BACT and installed at facilities located in cold climates. Some examples of SCR installed at coal-fired boilers in cold climates are the Boswell Energy Center in northern Minnesota, the Big Stone power plant in eastern South Dakota, and the Jim Bridger power plant in Wyoming.

SCR has also been required as BACT and/or installed at natural gas-fired compressor turbines. Specifically, SCR was proposed to meet BACT requirements for the proposed Buckingham Compressor Station to be located in Virginia, with all four combustion turbines ranging from 6,276 to 15,900 hp to be subject to a NOx BACT emission limit of 3.75 ppmv at 15% oxygen.[63] In addition, SCR was proposed to

[62] The specific information on these RBLC entries can be found by searching on the RBLC ID number at https://cfpub.epa.gov/rblc/index.cfm?action=Search.SearchByRBLCIdentifier.

[63] *See* January 9, 2019 Registration No. 21599, attached as Ex. 5. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated.

be installed at the Charles Compressor Station to be located in Maryland,[64] the Northampton Compressor Station to be located in North Carolina,[65] and the Marts Compressor Station to be located in West Virginia.[66] And several California air districts have adopted rules requiring existing gas-turbines including compressor turbines to meet NOx limits in the range of 2.5 – 3.5 ppmv that would essentially require installation of SCR.[67]

For power generating combustion turbines operating in combined cycle mode, NOx emission limits of 2.0 ppmv @ 15% $O_2$ are commonly required to meet BACT. The table below shows the RACT/BACT/LAER Clearinghouse ID for numerous such permitted combined cycle units with SCR and NOx BACT limits of 2.0 ppmv @15% $O_2$. There are numerous other combined cycle combustion turbines in the EPA Clearinghouse that also have 2.0 ppmv NOx limits to be met with SCR, but either have less stringent averaging times or don't require CEMs for compliance (or the EPA Clearinghouse doesn't specify the averaging time or whether CEMs are required). Thus, there is ample support for a 2.0 ppmv NOx BACT emission limit for SCR at combined cycle power generating combustion turbines.

**Table 4. Most Stringent NOx BACT Emission Limits for Natural Gas-Fired Combined Cycle Power Plants in EPA's RACT/BACT/LAER Clearinghouse (2.0 ppmv NOx limits with Short Term Averaging Time and CEMs Required for Compliance)**

| RBLC ID | Name of Facility | Size of NG-Fired Combined Cycle Units | NOx limit and Averaging Time |
|---|---|---|---|
| VA-0332 | Chickahominy Power | 319 MW | 2.0 ppmvd, 1-hour average, CEMs |
| VA-0328 | Novi Energy C4GT, LLC | ~4,000 MMBtu/hr (w/duct burner) | 2.0 ppmvd, 1-hr average, CEMs |
| VA-0325 | (VA Electric& Power Co) Greensville Power Station | 3227 MMBtu/hr | 2.0 ppmvd, 1-hr avg, CEMs |
| CA-1251 | Palmdale Energy Project | 2217 MMBtu/hr | 2.0 ppmvd, 1-hr average, CEMs |
| CT-0161 | Killingly Energy Center | 3,585 MMBtu/hr (w/duct burner) | 2.0 ppmvd, 1-hr average, CEMs |
| OH-0367 | South Field Energy LLC | 3,391 MMBtu/hr (w/duct burner) | 2.0 ppmvd, 1-hr avg, CEMs |
| IL-0129 | CPV Three Rivers LLC | 3,474 MMBtu/hr | 2.0 ppmvd 3 unit-hourly average (after 36 months, |

64 *See* Draft Permit for Dominion Energy Cove Point – Charles Station, *available at*: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20ptc%20conditions%20for%20compressor%20station2018.pdf and attached as Ex. 13. It is not clear whether the final air permit has been issued yet for this facility.

65 *See* Air Permit No. 10466R00, issued February 27, 2018, for Northampton Compressor Station, attached as Ex 14.

66 *See* Permit No. R13-3271, issued July 21, 2016, for Marts Compressor Station, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf and attached as Ex. 15.

67 These air districts include the South Coast Air Quality Management District (NOx limit of 3.5 ppm for compressor gas turbines) and the Ventura County Air Pollution Control Division (NOx limit of 2.5 ppmv is proposed to be required for all existing turbines beginning 1/1/24).

| | | | |
|---|---|---|---|
| | | | limit applies per unit on hourly basis), CEMs |
| IL-0310 | Jackson Energy Center | 3864 MMBtu/hr | 2.0 ppmvd (3-hr rolling average for 1st 36 months, then 1-hr avg), CEMs |
| NJ-0085 | Middlesex Energy Center | 633 MW | 2.0 ppmvd, 3-hr rolling avg, CEMs |
| MI-0442 | Thomas Township Energy | 625 MW | 2.0 ppmvd, 24-hr rolling average, CEMS |
| MI-0432 | New Covert Generating Co. | 1239 MW (3 combined cycle units) | 2.0 ppmvd, 24-hour rolling average, rolled hourly, CEMs |
| MI-0435 | Belle River Combined Cycle Power Plant | 1,150 MW (2 combined cycle units) | 2.0 ppmvd, 24-hr rolling average, rolled hourly, CEMs |
| MI-0433 | Marshall Energy Center | 500 MW | 2.0 ppmvd, 24-hr rolling average, rolled hourly, CEMs |
| MI-0431 | Indeck Niles LLC | 4161 MMBtu/hr (w/duct burner) | 2.0 ppmvd, 24-hr rolling average, rolled hourly, CEMs |
| TX-0819 | Gaines County Power Plant | 426 MW | 2.0 ppmvd, rolling 24-hr average, CEMs |
| FL-0367 | Shady Hills Energy Center | 385 MW | 2.0 ppmvd 24-hr block avg, CEMs |

Notes: All NOx emission limits in ppmvd are at 15% oxygen.

Based on the research presented above of NOx emission rates required to meet BACT and other Clean Air Act requirements, I prepared SCR cost analyses for the compressor turbines for the most stringent end of the NOx limits achievable at gas turbines with SCR of 2.0 ppmv@15% $O_2$, but I also evaluated an upper end of the NOx limits that have been required for compressor turbines of 3.5 ppmv@15%$O_2$ for Alaska LNG's compressor turbines. I evaluated SCR cost effectiveness for the power turbines to be constructed at Alaska's LNG plant based on meeting a 2.0 ppmv NOx BACT limit. The controlled NOx emission rates that were input into EPA's SCR Cost Spreadsheet are identified in the table below.

**Table 5. NOx Emission Rate Scenarios Evaluated for Alaska LNG Compressor Turbines and Power Turbines**

| NOx Emission Rate Scenario Evaluated | NOx Inlet Rate, lb/MMBtu | NOx Outlet Rate, lb/MMBtu | NOx Removal Efficiency Required by SCR |
|---|---|---|---|
| 1 (Evaluated for compressor turbines and power turbines) | 0.1002 lb/MMBtu (converted from 25 ppmv@15% $O_2$) | 0.008 lb/MMBtu (converted from 2 ppmv@15% $O_2$) | 92% |
| 2 (Evaluated only for compressor turbines) | 0.1002 lb/MMBtu | 0.0140 lb/MMBtu (converted from 3.5 ppmv@at%$O_2$) | 86% |

The results of the revised cost effectiveness of SCR at the Alaska LNG compressor turbines to meet 1) a NOx limit of 2 ppmv@15% $O_2$ and 2) a NOx limit of 3.5 ppmv@15% $O_2$ from a baseline of 25 ppmv@15%$O_2$ are provided in the table below.

**Table 6. Cost Effectiveness of SCR at Alaska LNG's Compressor Turbines, Based on a 25-Year Life of Controls (2019 $)[68]**

| NOx Emission Limit with SCR, ppmv@15% $O_2$ | Capital Cost of SCR | Operation and Maintenance Costs of SCR, $/year | Total Annualized Cost, $/year | NOx Reduced with SCR, tpy | Cost Effectiveness of SCR at stated NOx limit, $/ton |
|---|---|---|---|---|---|
| 2.0 | $12,042,676 | $851,512 | $1,565,380 | 449 tpy | $3,483/ton |
| 3.5 | $12,042,676 | $836,120 | $1,549,988 | 420 tpy | $3,689/ton |

The results of the revised cost effectiveness analyses of SCR for the Alaska LNG combined cycle power turbines to meet the commonly required BACT limit of NOx limit of 2 ppmv@15% $O_2$ are provided in the table below.

**Table 7. Cost Effectiveness of SCR at Alaska LNG's Combined Cycle Power Turbines, Based on a 30-Year Life of Controls (2019 $)[69]**

| NOx Emission Limit with SCR, ppmv@a5% $O_2$ | Capital Cost of SCR | Operation and Maintenance Costs of SCR, $/year | Total Annualized Cost, $/year | NOx Reduced with SCR, tpy | Cost Effectiveness of SCR at stated NOx limit, $/ton |
|---|---|---|---|---|---|
| 2.0 | $6,029,988 | $502,329 | $823,099 | 155 tpy | $5,308/ton |

As the above tables demonstrate, SCR at the Alaska LNG compressor turbines and the power turbines to reduce NOx from a 25 ppmv NOx baseline to meet an emission limit in the range of 2.0 to 3.5 ppmv @ 15% $O_2$ is clearly cost effective. These costs are much lower than the $10,000/ton cost effectiveness threshold that AGDC claims is ADEC's upper bound cost effectiveness limit.[70] Moreover, these costs should be considered cost effective because of the fact that other similar sources have had to incur the costs of installing and operating SCR to meet NOx BACT. Indeed, that latter fact must be instructive to ADEC. 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."[71]

Not only have NOx BACT limits been based on application of SCR to gas turbines used at compressor stations, a recent air permit for Driftwood LNG plant to be located in Louisiana requires that the

[68] *See* SCR Cost Calculation Spreadsheets for Alaska LNG Compressor Turbines, attached as Exs. 16 and 17.
[69] *See* SCR Cost Calculation Spreadsheet for Alaska LNG Power Turbines, attached as Ex. 18.
[70] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 10.
[71] EPA, New Source Review Workshop Manual, October 1990, at B.29.

compressor turbines meet a NOx BACT emission limit based on installation of SCR. *See* EPA RACT/BACT/LAER Clearinghouse ID # LA-0349 (PSD Permit Number PSD-LA-829, issued 5/23/2018). While the NOx BACT limit for the Driftwood LNG compressor turbines is 5.0 ppmv@15% $O_2$, which is much less stringent than the NOx removal efficiencies achievable with SCR, the fact that the state of Louisiana based its NOx BACT limit on installation of SCR shows that SCR has been found to be cost effective to meet BACT at compressor turbines used at a LNG facility. In addition, SCR has been required to meet a 2.0 ppmv NOx BACT limit at an 87 MW combustion turbine at the Freeport LNG Plant. *See* EPA RACT/BACT/LAER Clearinghouse ID # TX-0678 (PSD Permit Number PSDTX1302, issued 7/16/2014). While it is not clear whether this combustion turbine is used as power generating or as a compressor turbine, it is being used as a cogeneration unit in that the exhaust heat will be used as a heating medium to regenerate rich amine from the acid gas removal system of the Freeport plant, according to information in EPA's RACT/BACT/LAER Clearinghouse for this permit. This provides another directly relevant example of SCR being required to meet BACT at similar compressor and power turbines to those proposed to be installed at the Alaska LNG plant.

Thus, ADEC must base its NOx BACT emission limit on application of the same control technology required to meet BACT at other similar combustion turbines unless AGDC can show there are unique circumstances that exist at its LNG compressor turbines or at its power generation turbines that make application of SCR not technically feasible for either of the turbines or that the costs for SCR at its compressor turbines would be much higher than the cost of SCR at the other similar turbines that have been required to meet BACT emission limits based on SCR. Based on the information submitted in AGDC's permit application, the company has not provided any information to make an argument that unique circumstances exist for its proposed compressor turbines that would make SCR not technically feasible or otherwise more costly than other similar sources. Compressor turbines can be operated at variable loads and peaking turbines are clearly operated at variable loads, yet SCR has been required on both to meet low NOx limit. Thus, any claims AGDC might make about how the compressor turbines or power turbines will be operated to justify excluding SCR as BACT are not supported when there are examples of such turbines with similar operational conditions that are required to install SCR to meet BACT. Further, the fact that other facilities in Alaska have been required to install SCR[72] negates any argument about the varying temperature ranges in Alaska as negating SCR as a BACT control. In fact, ADEC very recently proposed to require SCR as BACT along with Solar turbines' SoLoNOx combustors for six power generating combustion turbines at the Agrium U.S., Kenai Nitrogen Operations plant, which will also be located in Nikiski, Alaska.[73] In any event, if AGDC was to make such a demonstration that unique circumstances exist to justify not requiring the top level control for its combustion turbines that has been required at similar sources to meet BACT, it must provide the details of those unique circumstances in a publicly available document. Such public details must include the cost analysis, if the company claims unique and unreasonable costs as a justification to eliminate SCR from consideration.

It must also be noted that even more cost-effective methods for controlling NOx to these levels might be an option for the Alaska LNG combustion turbines. For example, one or more turbines could share

[72] As discussed in Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 18.

[73] *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, available at https://dec.alaska.gov/Applications/Air/airtoolsweb/AirPermitsApprovalsAndPublicNotices, and attached as Ex. 19.

an SCR reactor, depending on proximity. Indeed, routing the flue gas to a shared SCR could help and/or provide options to reduce the exhaust gas temperature from the compressor turbines to optimize NOx removal across the SCR. The Salt River Project (SRP) is planning to route the flue gas from one boiler at the Coronado Generating Station in Arizona to an existing SCR reactor that had previously been constructed at another boiler at Coronado station.[74] The Coronado SCR will be a shared SCR system, although the existing SCR at Coronado Unit 1 was designed as a split (two towers within one reactor) SCR system. So, according to SRP, each unit will have its own SCR within one reactor. Such an approach seems like it could be a viable, more cost-effective control option for co-located combustion turbines at compressor stations and/or for co-located power generating turbines at the Alaska LNG plant.

For all the above reasons, ADEC must impose a NOx BACT emission limit for the compressor turbines reflective of SCR to meet a NOx limit of 2.0 ppmv@15% $O_2$ unless it can be adequately demonstrated that this limit is technically infeasible for the Alaska LNG compressor turbines, in which case the NOx limit should be no higher than 3.5 ppmv@15% $O_2$. In addition, ADEC must impose a NOx BACT emission limit on the combined cycle power turbines reflective of SCR to meet a NOx limit of 2.0 ppmv@15% $O_2$. Further, compliance with the NOx BACT emission limits must be based on a short term compliance period to assure compliance with the 1-hour $NO_2$ ambient air quality standard and must be based on the use of continuous emissions monitoring systems (CEMs) which, as shown in Table 4 above is commonly required for BACT compliance.

### B. BACT for Carbon Monoxide for the Natural Gas-fired Compressor Turbines and the Power Turbines

AGDC has proposed to utilize an oxidation catalyst to meet a CO BACT limit of 10.0 ppmv@15% $O_2$ at both the compressor turbines and at the power turbines.[75] This CO emission limit 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.[76] ADEC proposed a lower CO limit as BACT of 5 ppmv@15% $O_2$.[77] However, rather than 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 that analysis of 5 ppmv@15% $O_2$ for both the compressor turbines and the power turbines.[78] This is not a proper method of setting a BACT emission limit.

BACT is to be based on the maximum degree of emission reduction that can be achieved considering the costs of controls and other environmental and energy factors. Neither AGDC nor ADEC provided any economic or other basis for not considering a lower CO limit as BACT. EPA states that "the most effective level of control must be considered in the BACT analysis" and that "different levels of control

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[74] *See* January 6, 2020, SRP Newsroom, SRP Selects Operation Plan for Coronado Generating Station, Units 1 and 2 to Run on Existing Selective Catalytic Reduction until 2032, available at [https://media.srpnet.com/srp-selects-operation-plan-for-coronado-generating-station/](https://media.srpnet.com/srp-selects-operation-plan-for-coronado-generating-station/).
[75] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 10 and at 26.
[76] *Id.* at 8 (Table 3-6) and at 24-25 (Table 4-6).
[77] *Id.*, Appendix B at 10 and at 27.
[78] *Id.* at 10 and at 27.

for a given control alternative can also be considered."[79] Thus, ADEC must evaluate the most stringent CO BACT limit required with its selected BACT control of oxidation catalyst, which it identified as 1.5 ppmv for simple cycle turbines and as 0.9 ppmv for combined cycle turbines.[80] Then, if that emission limit is not cost effective or if other documented energy or environmental factors justify a higher CO limit for either the compressor turbines or the power turbines, ADEC can evaluate a higher BACT limit. 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 process that EPA follows. ADEC must follow that process and impose a CO BACT limit reflective of the maximum degree of CO emission reduction achievable at the Alaska LNG compressor turbines and at the power turbines.

## C. BACT for GHG from the Compressor Turbines (EU 1-6) and the Power Turbines (EU 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.[81] 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. Under the proposed BACT limits, each compressor turbine would have the potential to emit 570,855 tons per year, or a total of 3.4 million tons of GHG emissions per year from the six compressor turbines. Each power turbine would have the potential to emit GHG emissions of 196,953 tons per year, or a total of 787,811 tons of GHG emissions per year. The grand total potential to emit from all ten combustion turbines is 4.2 million tons of GHG emissions per year. That total of potential GHG emissions from the gas turbines puts the turbines on par with the GHG emissions of approximately a 500-megawatt coal-fired power plant unit or an 1,100 MW natural gas-fired combined cycle power plant. These potential GHG emissions from the combustion turbines are quite significant, and thus warrant a thorough review of potential BACT controls.

### 1. Carbon Capture and Sequestration

According to ADEC's Technical Analysis Report, AGDC conducted a cost analysis of carbon capture and sequestration for the $CO_2$ emissions from the six compressor turbines along with the four power turbines.[82] ADEC states that the economic analysis of CCS "included cost data from a study conducted by URS Corporation for AGDC's Gas Treatment Plant in 2010 entitled, 'Alaska Pipeline Project Gas Treatment Plant: $CO_2$ Capture Study' as well as cost data from the Golden Pass LNG Project PSD Permit Application."[83] However, ADEC did not explain how the URS study cost numbers were used to derive the cost estimates specific to the application of CCS to the proposed liquefaction facility. The URS study appears to have been done (based on its title) for the AGDC Gas Treatment Plant to be located on the North Slope of Alaska and not for the LNG Plant that will be some 800 miles to the south in Nikiski Bay

[79] EPA, New Source Workshop Manual, at B.23 to B24.
[80] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 8 and at 25.
[81] *Id.* at 19 and at 36.
[82] *Id.* at 18.
[83] *Id.*

that is being addressed in this current permit. Given that having a suitable location for sequestration of the carbon is an important part of the feasibility and cost analysis of CCS, the study done for the Gas Treatment Plant may not be entirely applicable to the costs of CCS at the LNG facility.

ADEC also states that the CCS costs were also based on the Golden Pass LNG Project Permit Application.[84] The Golden Pass LNG project is a proposed LNG plant to be located in Sabine Pass, Texas. Neither AGDC nor ADEC explained how the data from the Golden Pass LNG project was applied to evaluating CCS for the turbines to be installed at the Alaska LNG plant. Indeed, AGDC's BACT submittal does not appear to include any site-specific costs for CCS at the LNG facility and instead it states that costs "are based on data for other comparable facility analyses, or data provided by the EPA" and the facility that AGDC relied on was the Golden Pass facility in Texas.[85]

The economic analysis AGDC presented in its 2018 BACT analysis is not the same as the "AGDC Analysis" presented in ADEC's Preliminary Technical Analysis Report, in that the total annualized costs are different ($543.3 million per year in AGDC's 2018 BACT analysis compared to $623.3 million per year in Table 3-11 of ADEC's September 11, 2020 TAR). Further, the amount of GHG emissions reduced is identified as much lower in the AGDC 2018 BACT submittal compared to Table 3-11 of the ADEC TAR (1.2 million in AGDC's 2018 BACT submittal versus 3,779,734 tons per year in the ADEC TAR). Thus, the actual cost data being relied on by ADEC must be clear and accurately disclosed, such as the capital cost of CCS for the Alaska LNG Plant, the transportation costs and assumptions, the operational costs and assumptions, and any other costs included. In addition, the details of the GHG reduction calculations must be documented. ADEC must also make available to the public the cost analysis for CCS at the Golden Pass LNG project that it cites in its Technical Analysis Report.

Moreover, AGDC cannot base a determination of whether CCS is cost effective for the Alaska LNG plant on the cost analysis of CCS for another LNG plant in Texas or for a gas processing plant to be located on the North Slope of Alaska. As discussed in AGDC's 2018 BACT submittal, there are several aspects of the proposed location of the Alaska LNG plant that may make CCS more viable for its plant than for an LNG plant located in Texas. Specifically, according to AGDC's 2018 BACT submittal, "[t]he *United States 2012 Carbon Utilization and Storage Atlas* (Fourth Edition published by the U.S. Department of Energy, Office of Fossil Energy) identifies an extensive saline aquifer directly below Nikiski [the proposed location of the LNG facility] as being 'screened, high sequestration potential.'"[86] AGDC's BACT submittal explains the following about saline aquifer injection:

> Saline aquifer injection systems pump $CO_2$ into deep saline aquifers. Saline aquifers may be the largest long-term subsurface CCS option. Such aquifers are generally saline and are usually hydraulically separated from the shallower "sweet water" aquifers and surface water supplies accessible by drinking water wells. The injected $CO_2$ displaces the existing liquid and is trapped as a free phase (pure $CO_2$), which is referred to as "hydrodynamic trapping." A fraction of the $CO_2$ will dissolve into the existing fluid. The ultimate $CO_2$ sequestration capacity of a given aquifer is the difference between the total capacity for $CO_2$ at saturation and the total inorganic carbon currently in solution in that aquifer. The solubility of $CO_2$ depends on the pressure, temperature, and salinity of

[84] *Id.*
[85] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 61.
[86] *Id.* at 61.

> the formation water. Low salinity, low temperature, and high pressure environment is the most effective for sequestering $CO_2$ in widespread, deep, saline aquifers. The potential sequestration capacity of deep horizontal reservoirs is many times that of depleted, really restricted, structural or stratigraphic oil and gas reservoirs.

Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 60.

$CO_2$ transportation costs are a significant part of the costs of CCS, and such costs will differ depending on where the $CO_2$ would be sequestered. That determination will be different for a plant located on the north slope of Alaska compared to a plant located near Port Arthur, Texas compared to a plant located in Nikiski, Alaska in the Cook Inlet. Clearly, the location of the proposed Alaska LNG plant may be a prime area to consider for sequestration of carbon. Yet AGDC inexplicably states that because the area "has not had a detailed evaluation for $CO_2$ sequestration and lies in a fault zone,"[87] it cannot be considered suitable for CCS for the Alaska LNG Project.

Part of the BACT evaluation process must include determining the suitability of a potential pollution control, particularly a top, most effective control, for a particular source. CCS is the primary method that has been identified by EPA, along with the less effective GHG control (in comparison) of energy efficiency, in EPA's GHG Permitting Guidance. Specifically, EPA states:

> For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology [fn omitted] that is "available" [fn omitted] for facilities emitting $CO_2$ in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity $CO_2$ streams (*e.g.,* hydrogen production, ammonia production, *natural gas processing*, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources. Many other case-specific factors, such as the technical feasibility and cost of CCS technology for the specific application, size of the facility, proposed location of the source, and availability and access to transportation and storage opportunities, should be assessed at later steps of a top-down BACT analysis. However, for these types of facilities and particularly for new facilities, CCS is an option that merits initial consideration and, *if the permitting authority eliminates this option at some later point in the top-down BACT process, the grounds for doing so should be reflected in the record with an appropriate level of detail*.

EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011, at 31-32 [emphasis added].[88]

As stated in the above quote, if the permitting authority is going to eliminate CCS from consideration as BACT, "the grounds for doing so should be reflected in the record with an appropriate level of detail."[89] AGDC has not claimed it has studied CCS for applicability to the Alaska LNG plant. To the contrary, AGDC states: "At present, it is unclear if the technology could be employed at the LNG Plant. Detailed design

[87] *Id.*

[88] Available at https://www.epa.gov/sites/production/files/2015-12/documents/ghgpermittingguidance.pdf.

[89] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011, at 31-32.

studies would be required to assess CCS feasibility."[90] ADEC cannot conclude that CCS is not cost effective for the Alaska LNG project without a site-specific evaluation of this highly effective GHG control. Thus, ADEC's evaluation of CCS for the Alaska LNG facility is wholly deficient.

### 2. Use of Electric Compressors

Another top BACT control option for the compressor turbines is the use electric compressors, thereby eliminating all GHG emissions as well as other pollutant emissions from the turbines. Indeed, use of electric compressors is the top level BACT control option for all pollutants. AGDC did identify use of electric motors as a GHG BACT control, but AGDC eliminated this control from further consideration for the compressor turbines because it claimed it would redefine the source given that the LNG plant would not be connected to the local electrical power grid.[91] For the power generating turbines, AGDC did not consider connection to the electrical grid system in lieu of constructing the power turbines as redefining the source, but instead stated that the grid "does not provide adequate energy to meet the normal operating requirements of the facility."[92] ADEC, on the other hand, excluded the evaluation of using electric compressors or using electricity from the grid to replace its proposed power turbines in the GHG BACT analysis of its Technical Analysis Review.

AGDC rejected use of electric compressors, whether powered from an offsite power plant or powered by the planned onsite power generating combined cycle units, as "fundamentally redefining the nature of the proposed source…."[93] The nature of the proposed source is a natural gas liquefaction plant, for which compressors are needed to operate refrigeration compression strings that will be installed in parallel, two per LNG line.[94] AGDC states that natural gas turbines will drive the compressor strings.[95] According to EPA's GHG Permitting Guidance, the permitting authority should "take a 'hard look' at the applicant's proposed design in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility."[96] For example, AGDC indicates in its permit application that the LNG project "requires year-round LNG export by waterborne vessels" and that the purpose and need of the project is "water-dependent."[97] This is a design element inherent to the applicant's purpose. Conversely, having compressors powered by natural gas is not necessarily inherent to the applicant's purpose. Requiring the use of electric compressors in lieu of natural gas-fired combustion turbines to drive the compressors would still achieve AGDC's basic business purpose for the liquefaction process, and thus electric compressors should be considered as a GHG BACT option.

[90] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 61.
[91] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 30.
[92] *Id.* at 44.
[93] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 30.
[94] *See* Alaska LNG Permit Application, Resource Report No. 1, April 14, 2017, General Project Description at 1-9, at pdf page 98 of file named "AQ1539CPT01 Application Attachments 1 through 3.pdf."
[95] *Id.*
[96] U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011, at 26.
[97] Alaska LNG Application, Resource Report No. 1, April 24, 2017, at 1-4 (fn 10), at pdf page 93 of file named "AQ1539CPT01 Application Attachments 1 through 3.pdf."

The PSD regulations provide that for a new source such as the Alaska LNG plant, the new "major stationary source shall apply best available control technology." [98] The definition of "BACT" requires that BACT be based on the "maximum degree of emission reduction for each pollutant…which would be emitted from any proposed major stationary source…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…through application of production processes or available methods, systems, and techniques…."[99] BACT for GHG emissions needs to be evaluated holistically for a source, given that energy efficiency is one of the primary methods of reducing greenhouse gas emissions. Thus, ADEC should have evaluated electric compressors as a BACT option for the Alaska LNG facility.

There are several additional air emissions benefits associated with the use of electric compressors. Those include that the maintenance requirements with an electric compressor are significantly less than with gas-fired compressor engines.[100] With less maintenance requirements, compressor downtime will be minimized which also reduces the flaring of the excess natural gas that normally would occur during turbine maintenance. It also seems likely that an electric engine would be less prone to upsets that cause the engine to go offline, compared to a gas-fired reciprocating engine, which would also reduce flaring emissions. Moreover, with no gas used in the compressor engine, fugitive emission leaks due to the fuel gas input to the turbines would also be eliminated. EPA's Natural Gas STAR Program Fact Sheet provided an estimate that methane emissions savings from replacing the five gas-fired compressor engines with electric engines could be as high as 16,000 million cubic feet per year, based on a methane emission factor of 2.11 MCF per horsepower.[101] Using the 100-year global warming potential identified by EPA,[102] that equates to roughly 10,000 tons per year of $CO_2$ equivalent emissions that would be avoided with no natural gas fugitive emission releases due to blowdowns with electric compressor engines.

Other benefits of electric engines include that[103]

- Electric engines are more efficient than gas-fired engines.
- Lower noise levels with electric motors compared to gas-fired engines.
- No on-site emissions of other air pollutants.

There are several examples of electric engines being used in the oil and gas industry for compression, both at the wellhead and in compressor stations.[104]

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[98] 40 C.F.R. 52.21(j)(2), incorporated into Alaska's rules at 18 AAC 50.040(h)(8).
[99] 40 C.F.R. 52.21(b)(12) [emphasis added], incorporated by reference into Alaska's rules at 18 AAC 50.040(h)(4).
[100] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2, available at https://www.epa.gov/natural-gas-star-program/install-electric-compressors and attached as Ex. 20.
[101] *Id.* at 1.
[102] *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why.
[103] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2, attached as Ex. --.
[104] 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, at 29-30, *available at*: https://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf and attached as Ex. 21.

For these reasons, ADEC should consider electric compressors in lieu of natural gas-fired compressors. If grid capacity is truly limited, ADEC should at least consider electrification for at least some of the compressor needs of the LNG plant.

For the power turbines, AGDC stated that existing grid did not provide adequate energy to replace the power turbines. The power turbines are much smaller than the compressor turbines, at about 40 megawatts each.[105] ADEC must require AGDC to provide more information to support the claim that the grid cannot support the electricity needs of the LNG plant that are currently planned to be provided by the power turbines. AGDC's permit application indicates that power from the grid will be used to meet onsite electricity needs for construction and estimates construction power needs to be in the range of 20-25 MW.[106] So, clearly, at least that much capacity in the grid is available to AGDC. In addition, the local utility, Homer Electric Association, has a battery energy storage system planned that would ensure 46.5 MW per hour on a reliable basis.[107] ADEC must evaluate whether AGDC could use at least part of this energy source, which would be very compatible with renewable energy generators, to meet the electricity demands of the LNG facility. For example, if even one of the planned power-generating turbines could be instead replaced with power generated from renewable energy from the grid, that could reduce GHG emissions by up to 196,953 tons per year. Thus, ADEC was without justification to dismiss the replacement of one or more power turbines with electricity from the power grid as a GHG BACT measure.

### 3. Use of Aeroderivative Turbines

AGDC states the following regarding aeroderivative turbines in its BACT analysis for the compressor turbines:

> Aero-Derivative turbines are used in gas compression and electrical power generation operations due to their ability to be shut down and handle load changes quickly. They are also used in the marine industry due to their reduced weight. In general, aero-derivative machines are more efficient than industrial machines of comparable size and capacity.

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

AGDC also states that "other comparable LNG projects have incorporated [aeroderivative turbines] into their design" including Sabine Pass, Trunkline Project, and Corpus Christi.[108] Aeroderivative turbines have also been proposed as the compressor turbines for the Jordan Cove LNG project to be located in Oregon. AGDC further states that "aero-derivative turbines are an attractive option, as they typically represent the most efficient simple-cycle turbine design available"[109] and that "[t]hermal efficiency

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[105] Table EC-4 of Attachments 4 and 5 of 2018 Alaska LNG Permit Application (pd 371 of electronic file).
[106] *See* Alaska LNG Permit Application, Doc. No. UAAI-PE-SRREG-00-000001-000, April 14, 2017, at 1-xix, and April 24, 2017 Resource Report No. 1 at 1-17 (at pdf pages 26 and 106 of file named "AQ1539CPT01 Application Attachments 1 through 3.pdf").
[107] https://www.homerelectric.com/2019/12/battery-energy-storage-system-bess-coming-to-hea/.
[108] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 29.
[109] *Id.* at 32-33.

increases between 4% and 8% are possible over comparable industrial/frame design turbines."[110] In fact, AGDC's claimed improvement in efficiency seems low. A 2012 industry journal article stated that "[t]oday's aeroderivative gas turbines offer 10-15% more efficiency compared to heavy frame industrial gas turbines."[111] This increased efficiency means aeroderivative turbines use less fuel and thus would emit less GHG emissions than non-aeroderivative turbine models. Thus, use of aeroderivative turbines should clearly be considered as a GHG BACT option.

AGDC provided an economic analysis of the incremental cost to achieve GHG reductions using aeroderivative turbines compared to an unidentified (no specified make or model) "evaluated model" compressor turbine.[112] AGDC showed that the incremental cost of using an aeroderivative turbine compared to the "evaluated model" turbine would cost $32/ton, yet AGDC claimed that use of an aeroderivative turbine "would only be considered BACT if turbine fuel costs are $7.50/MMBtu or greater."[113] Presumably because the fuel costs at the Alaska LNG compressor turbines are considered "negligible,"[114] AGDC did not propose use of aeroderivative engines as BACT for GHG emissions. It seems that AGDC evaluated whether to propose aeroderivative engines as BACT based on whether the total annualized capital and operational costs of aeroderivative engines were equivalent to or less than the total annualized capital and operational costs of the "evaluated model" turbine. However, it is generally a given in a BACT analysis that an analysis of a pollution control would have some economic impact. The question to be answered by the cost effectiveness analysis is whether it is cost effective to use aeroderivative turbines, which would emit less GHG emissions for the same amount of power generation.

While AGDC did not include the details of its cost effectiveness analysis in the BACT section of it permit application, some details were included in a spreadsheet that was made available to National Parks Conservation Association in November 2020. Specifically, a spreadsheet entitled "23_Trade Secret_cost effectiveness_Compression Turbines" that was included in the "2018.05.01 Original Submittal" compressed file has some additional details on the aeroderivative turbine cost effectiveness analysis. There were several assumptions made in that cost analysis that would overstate the "incremental cost effectiveness" of use of aeroderivative turbines compared to industrial frame turbines. First, a 7% interest rate was assumed in amortizing capital costs of the turbines.[115] As previously stated, EPA recommends using the current bank prime lending rate in amortizing capital costs of controls, and it is currently 3.25%.[116] Second, AGDC's analysis assumed that twelve aeroderivative turbines of 51 MW output each would be needed to replace the six planned compressor turbines of 114 MW output each.[117] It is not clear why AGDC did not evaluate simply replacing the planned 114 MW turbines with similar-sized aeroderivative turbines. For example, the GE LMS100 aeroderivative turbines have a

[110] *Id.* at 33.
[111] *See* Almasi, Amin, Gas turbine selection: Heavy frame or aeroderivative, Turbomachinery International, April 25, 2012, available at https://www.turbomachinerymag.com/gas-turbine-selection-heavy-frame-or-aeroderivative/.
[112] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 33-34.
[113] *Id.* at 34.
[114] *Id.*
[115] *See* spreadsheet entitled "23_Trade Secret_cost effectiveness_Compression Turbines" at row 24 of tab entitled "GHG-Incremental."
[116] *See* https://www.federalreserve.gov/releases/h15/.
[117] *See* spreadsheet entitled "23_Trade Secret_cost effectiveness_Compression Turbines" at rows 10 and 12 of "GHG – Incremental" tab.

similar output at 117 MW.[118] In fact, this GE turbine has been selected for compressor turbines for at least one LNG plant – LNG Canada.[119] By assuming that its planned six compressor turbines would need to be replaced with twelve aeroderivative turbines, AGDC inflated the capital costs of the aeroderivative turbines. Moreover, AGDC's annual maintenance costs are also overstated due to the assumption of twelve aeroderivative turbines rather than six aeroderivative turbines, because each turbine has to be maintained. An assumption of twice as many aeroderivative turbines as will be needed will likely double the annual maintenance costs. Further, the assumed heat rate of the aeroderivative turbines assumed in AGDC's analysis of 6,008 Btu/horsepower-hour, which equates to approximately 8,051 Btu/kW-hr, seems high. The LMS100 aeroderivative turbine heat rate is listed as 7,925 Btu/kW-hr.[120] The lower the heat rate is, the less fuel is burned and the lower the GHG emissions. Thus, by assuming a higher heat rate in its analysis of aeroderivative turbines, AGDC understated the amount of GHG emissions reduced and overstated the amount of fuel used by the aeroderivative turbines compared to the planned industrial turbines.

I revised AGDC's aeroderivative turbine incremental cost effectiveness analysis to address a few of these issues. First, I used a 3.25% interest rate in amortizing capital costs rather than the 7% interest rate assumed by AGDC. Second, I assumed a lower heat rate for the aeroderivative turbines. Specifically, I used the heat rate of the GE LMS100 turbine of 7,925 Btu/kW-hr,[121] which equates to 5,910 Btu/HP-hr.[122] Last, I used the 12-month average Henry Hub Natural Gas Spot Price for January to December of 2019 as the cost for natural gas, which was $2.57/MMBtu.[123] With just changing these three inputs in AGDC's cost effectiveness analysis, I estimate the incremental cost effectiveness of using aeroderative turbines instead of industrial frame turbines would be $60/ton assuming a spot price of natural gas of $2.57/MMBtu and would reduce GHG emissions by 410,000 tons per year.[124] Note that this analysis does not address the issue that AGDC overstated both capital and operational costs of using aeroderivative turbines by assuming that twelve aeroderivative turbines would be needed to replace the planned six industrial frame turbines. The cost per ton for using six similarly-sized aeroderivative turbines instead of the six planned compressor turbines (rather than assuming that twelve aeroderivative turbines would be needed) would very likely greatly reduce the incremental cost effectiveness of using aeroderivative turbines. In fact, if the same annual maintenance costs of $15,000,000 per year are assumed for the use of six aeroderivative turbines as was assumed for the planned six industrial frame turbines (instead of using AGDC's assumed $28,000,000 per year for annual maintenance for twelve aeroderivative turbines), the incremental cost effectiveness of use of aeroderivative turbines reduces to $29/ton.[125] Thus, it seems clear that use of aeroderivative turbines could be a cost effective GHG control, and use of such turbines could keep approximately 410,000 tons

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[118] *See* GE Fact Sheet for LMS100 Power Plants, Ex. 1. *See also* GE, Aeroderivative Gas Turbine, LMS100, at https://www.ge.com/power/gas/gas-turbines/lms100.
[119] *See* https://www.ge.com/news/press-releases/lng-canada-selects-ge-oil-gas-high-efficiency-lms100-gas-turbine-compressor-0.
[120] *See* Fact Sheet for GE LMS100 Gas Turbine, Ex. 1.
[121] *Id.*
[122] Based on the conversion factor of 1.34102 horsepower to kilowatts.
[123] *See* https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.
[124] *See* Ex. 22, spreadsheet entitled "Alaska LNG GHG Turbine Analysis Revised" at Tab 1. This spreadsheet is a copy of AGDC's worksheet entitled "23_Trade Secret_cost effectiveness_Compression Turbines" at "GHG – Incremental" tab, with changed cells highlighted in yellow (reflecting revised heat input rate, revised interest rate and capital recovery factor, and revised fuel cost).
[125] *Id.* at Tab 2. Calculated by changing the costs for maintenance on the aeroderivative turbines in cell C26 to be identical to the maintenance cost for six frame turbines of $15,000,000 per year.

per year of GHG emissions from being emitted simply by using more energy efficient turbines for the compressor turbines. 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.

ADEC's Technical Analysis Report dismissed the use of aeroderivative turbines for either the compressor turbines or the power turbines, claiming that use of aeroderivative turbines models "would fundamentally redefine the project…."[126] Yet, as previously stated, neither the Alaska LNG permit application nor the ADEC's Draft Permit identify the make and model of the planned compressor turbines. Further, AGDC did not argue that use of aeroderivative turbines would redefine the source. The fact that several LNG plants are or will be using aeroderivative turbines, as detailed in AGDC's permit application,[127] also negates any argument that evaluating aeroderivative turbines as a GHG BACT measure would redefine the source. ADEC's justification that consideration of aeroderivative turbines for the Alaska LNG compressor turbines would be redefining the source is that "the facility is currently designed to use six simple cycle turbines as the mechanical drivers for the refrigeration process of the natural gas" and that "[r]equiring the compressor turbines to be aeroderivative models would fundamentally redefine the project…."[128] Aeroderivative turbines *are* simple cycle turbines[129] that would also be the mechanical drivers for the refrigeration process. There is no redefinition of the source by considering an aeroderivative turbine in lieu of a heavy-duty frame turbine. In addition, aeroderivative turbines can also be used to produce electricity and in a combined cycle mode like the power turbines are planned for at the Alaska LNG facility. For example, GE's website on the LM6000 aeroderivative turbines indicates that the turbine can operate in simple cycle and combined cycle modes.[130] Further, given that neither the permit application nor the Draft Permit specify any make or model of the compressor turbines or the power turbines, ADEC is without justification to argue that use of an aeroderivative turbine to drive the refrigeration process or to generate power for the LNG facility is a redefinition of the source.

Aeroderivative turbines have other benefits that must also be considered, because they will reduce emissions of other pollutants from the turbines and/or will reduce air pollutants from elsewhere at the plant. One of those benefits include shorter turbine startup times. AGDC did not quantify startup emissions of NOx, CO or VOCs, but such startup emissions can be significant over the time it takes to startup the turbine when the pollution controls may not work as effectively. For example, in a GE document for the LM6000 turbines for Mariposa Energy, LLC, the company states that the turbine can achieve a 10 minute start and ramp up at 30 megawatts per minute.[131] Other GE documentation for aeroderivative gas turbines indicates a shorter time for startup of 5 minutes "From Cold Iron to Full

[126] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 17 and at 34.
[127] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 32.
[128] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 17.
[129] To the extent ADEC is stating that aeroderivative turbines are not used in simple cycle mode, that is not the case. For example, GE describes its LMS100 Aeroderivative Gas Turbine as "one of the highest simple cycle efficiency gas turbines in the world." *See* https://www.ge.com/power/gas/gas-turbines/lms100. Gas turbines of any type can be operated in simple cycle mode (where the turbine by itself generates electricity or mechanical power to drive a compressor) or in combined cycle mode, in which case a heat recovery steam generator is used to convert the waste heat to additional electricity.
[130] *See* https://www.ge.com/power/gas/gas-turbines/lm6000. *See also* Ex. 7, GE LM6000 Power Plants Fact Sheet.
[131] *See* GE Energy, VOC Emissions from LM6000 for Mariposa Energy, at page 2, available at https://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/20737/Application%20Correspondence%20and%20Supporting%20Documents/030-email%205-26-2010%20CH2M%20to%20Patil%20Attached%20Doc_13.ashx and attached as Ex. 23.

Power."[132] Emissions of NOx, CO, and VOCs during startup will be higher than during normal operation, so the decreased time period for startups will mean less emissions of these pollutants during startups.

The exhaust temperatures of aeroderivative turbines are also lower than heavy duty frame turbine engines. Lower exhaust temperatures would enable SCR to operate more effectively for control of NOx emissions.

In addition, the time needed for, and the frequency of, maintenance on aeroderivative turbines is significantly less than the time needed for maintenance on heavy duty frame turbines.[133] Less downtime for maintenance of the compressor turbines would equate to less flaring of the excess natural gas stream, and thus reduced emissions from flaring, while a compressor turbine is down for maintenance.

Thus, there are several emission reduction benefits of use of aeroderivative turbines compared to heavy duty frame turbines for the compressor turbines at the Alaska LNG facility. For all these reasons, ADEC should not have eliminated use of aeroderivative turbines as a GHG control option. As shown by the revised incremental cost analyses presented herein, the use of aeroderivative gas turbines would be very cost effective and would reduce GHG emissions by over 400,000 tons per year.[134] 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. 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 is Proposing as BACT

ADEC has proposed a GHG BACT limit of 117.1 lb/MMBtu averaged over a 3-hour period as BACT for both the compressor turbines and the power turbines, based on good combustion practices and burning clean fuels.[135] ADEC did not explain how it arrived at this emission limit. AGDC did not propose this BACT limit in its 2018 BACT analysis, although it claimed "[t]he compression turbine yields 1,163 pounds carbon dioxide per megawatt-hour (lb $CO_2$/MWh) as the base case emission level for the evaluated turbine model, which is more efficient than most industrial turbine designs." However, as previously stated, AGDC did not include any information in its permit application on the make or model of turbines to be installed, nor is any specific make or model mandated by the permit. Thus, AGDC's claim of the evaluated $CO_2$ emissions rate per megawatt-hour for its compressor turbines does not carry any weight, given that the permit does not specify the turbine make or model. In addition, AGDC did not include any documentation in its BACT analysis to indicate that the assumed $CO_2$ rate per megawatt-hour is more

[132] *See* GE, Advantages of Aeroderivatives Infographic, attached as Ex. 24.
[133] *See* Almasi, Amin, Gas turbine selection: Heavy frame or aeroderivative, Turbomachinery International, April 25, 2012, available at https://www.turbomachinerymag.com/gas-turbine-selection-heavy-frame-or-aeroderivative/.
[134] *See* Ex. 22, spreadsheet entitled "Alaska LNG GHG Turbine Analysis Revised."
[135] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 18.

efficient than most other turbine designs. Further, ADEC did not equate AGDC's assumed $CO_2$ rate per megawatt-hour to its proposed 117.1 lb/MMBtu GHG emission limit.

For the power turbines, 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.[136] However, despite finding that the combined cycle operation was a GHG BACT control, ADEC's GHG BACT determination for the power turbines was not based on the turbines operating in combined cycle mode. Instead, ADEC's GHG BACT determination was based on the power turbines "maintaining good combustion practices and burning clean fuels at all times…."[137] At the very minimum, ADEC's GHG BACT limit for the power turbines must be based on the combined cycle operation of the units. Yet, ADEC has proposed the same GHG BACT limit for the power turbines as the compressor turbines of 117.1 lb/MMBtu.[138] Further, while the Draft Permit identifies the power turbines as "combined cycle power generation combustion turbines," 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.[139]

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 Alaska LNG facility – that is, the compressor turbines, the combined cycle emission units, and the flares. In fact, ADEC's 117.1 lb/MMBtu GHG limit is simply the EPA GHG emission factor for natural gas combustion at any type of combustion source.[140] This limit does not reflect the maximum degree of GHG emission reduction achievable for the source considering costs of control and other impacts. Further, it is not a limit that will in any way encourage improvements in efficiency or even good combustion practices. The proposed GHG BACT limit for the power turbines will not even require the operation of the turbines in combined cycle mode. Thus, ADEC's proposed GHG limit of 117.1 lb/MMBtu does not reflect BACT.

EPA's GHG permitting guidance 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).[141] In addition, EPA states other requirements may also be imposed to ensure energy efficiency, such as an environmental management system focused on energy efficiency.[142] ADEC's GHG BACT limits for the compressor turbines and the power turbines do not provide for energy efficiency. The proposed BACT limits would not require any level of GHG control other than burning natural gas. As explained in detail above, 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

[136] Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 44.
[137] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 36.
[138] *Id.*
[139] 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.*
[140] *See* https://www.epa.gov/sites/production/files/2020-04/documents/ghg-emission-factors-hub.pdf. The emission factors for $CO_2$, methane ($CH_4$) and nitrous oxide ($N_2O$) convert to 117.1 lb/MMBtu (after applying the global warming potential factors in 40 C.F.R. Part 98, Table A-1.
[141] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011, at 46.
[142] *Id.*

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.

### D. ADEC Must Not Exempt Periods of Startup and Shutdown at the Compressor Turbines and the Power Turbines from BACT Emission Limits

ADEC has proposed to exempt periods of startup and shutdown from BACT emission limits for the compressor and power turbines.[143] Instead of requiring compliance with BACT emission limits during these time periods, ADEC simply requires that AGDC operate the turbines "according to manufacturer's specifications and good combustion practices."[144] ADEC's proposed work practice standards are vague and provide significant flexibility to AGDC without providing assurance that emissions will be minimized during these periods. In addition, the permit does not require any recordkeeping or reporting on the frequency, magnitude, and duration of exceedances of BACT emission limits during startup, shutdown, or malfunction, nor does the permit require any documentation that manufacturer's specifications and good combustion practices were followed during such periods. ADEC should either not allow any exemptions during periods of startup and shutdown, or ADEC must set alternative BACT emission limits during these periods that reflect BACT for the make and model of turbines that should also be specified in the permit.

Importantly, BACT is an "emission limitation," and an "emission limitation" is defined as a requirement that limits the rate of emissions "on a continuous basis."[145] ADEC's exemptions for complying with BACT limits during startup and shutdown are thus inconsistent with the definition of BACT. Further, it is feasible to impose alternative emission limits that apply during periods of startup and shutdown. In fact, every permit listed in Table 4 above sets alternative emission limits for startup and shutdown that were found to reflect BACT. In addition, many of the permits listed also impose limits on the duration and frequency of these startup and shutdown events. For example, in the PSD permit for the Palmdale Energy Center in California, issued by EPA Region 9, EPA set NOx and CO emission limits as well as time duration limits for cold startups, warm startups, hot startups, and shutdowns.[146] The PSD permit for Chickahominy Power Station in Virginia limits the duration of startups and shutdowns in minutes per event, and limits the pounds of NOx, CO, and VOC emissions per startup and shutdown event.[147] None of those permits listed in Table 4 have outright exemptions from BACT emission limits during startup and shutdown.

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 only apply to BACT limits for NOx, CO, and VOC emissions. For $SO_2$, $PM_{10}$ and $PM_{2.5}$ emissions, no exemption from BACT requirements should be authorized at all. A review of several of the RBLC entries for the sources

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[143] Draft Permit at 13 and 17.
[144] *Id.*
[145] 18 AAC 50.990(30). *See also* AS 46.14.990 and 40 C.F.R. §51.100(z).
[146] *See* Ex. 25, Palmdale Energy PSD Permit at 6-7 (Condition 19).
[147] *See* Ex. 4, Va. Dep't of Envtl. Quality, Permit Registration Number 52610, Chickahominy Power, LLC, Chickahominy Combined-Cycle Power Plant Project, at 12-13 (June 24, 2019).

listed in Table 4 finds that permitting authorities have generally established alternative emission limits for startup and shutdown for the NOx, CO, and VOC, but have not established alternative emission limits or allowed exemptions from BACT for PM or $SO_2$ BACT limits. That is because BACT for PM ($PM_{10}$ and $PM_{2.5}$) and $SO_2$ 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. Thus, ADEC is not justified in establishing exemptions or alternatives from BACT emission limits for PM and $SO_2$ at all during startup and shutdown.

BACT is to be met during all periods of operation, and thus 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.

# II. Comments on BACT for the Diesel-Fired Engines (EU 11 and 12)

The Alaska LNG 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.[148] 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, BACT can be no less stringent than the applicable NSPS standards. Specifically, the definition of BACT includes the following limitation: "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."[149] This NSPS backstop is often referred to as the "BACT Floor."

For new nonemergency stationary internal combustion engines, the NSPS requires that new engines must meet Tier 4 engine standards.[150] For engines the size of proposed Emission Units 11 and 12, the Tier 4 limits are as follows:

**Table 8. Tier 4 Emission Standards for Engines Between 130 – 560 kW (175 – 750 hp)[151]**

| Pollutant | Limit, g/kW-hr | Limit, g/hp-hr |
|---|---|---|
| ***NOx*** | 0.40 | 0.30 |
| ***PM*** | 0.02 | 0.015 |
| ***CO*** | 3.5 | 2.6 |
| ***Nonmethane hydrocarbons (NMHC)*** | 0.19 | 0.14 |

[148] Draft Permit at 12.
[149] *See* 40 C.F.R. §52.21(b)(12), incorporated by reference into Alaska's regulations at 18 AAC 50.040(h)(4). *See also* 40 C.F.R. §52.21(j)(1), incorporated by reference into Alaska's regulations at 18 AAC 50.040(h)(8).
[150] *See* 40 C.F.R.§60.4204(b); §60.4201(c); §1039.101 Table 1 (Tier 4 Exhaust Emission Standards After the 2014 Model Year). *See also* https://dieselnet.com/standards/us/nonroad.php#tier4.
[151] *See* 40 C.F.R. §1039.101 Table 1 (Tier 4 Exhaust Emission Standards After the 2014 Model Year). *See also* https://dieselnet.com/standards/us/nonroad.php#tier4.

Because there are NSPS emission limits that exist for this source category of diesel-fired engines, ADEC's BACT limits can be no less stringent than these BACT floor limits pursuant to the definition of BACT. Yet, ADEC has proposed BACT limits for these engines that are less stringent than the BACT floor. Specifically, for the auxiliary air compressor engine (EU 12), ADEC imposed BACT emission limits equivalent to Tier 4 final emission limits increased by a 50% "factor of safety" for NOx, volatile organic compounds (VOCs as NMHC), and PM and increased by a 25% factor of safety for CO.[152] There is absolutely no justification for including a factor of safety margin in the emission limits imposed on EU 12, allowing emissions to exceed Tier 4 emission standards that are required under the NSPS at 40 C.F.R. Part 60, Subpart IIII. ADEC cannot legally impose any emission limits less stringent than the Tier 4 final standards for the nonemergency diesel engines to be located at the Alaska LNG facility, because it would not be meeting the BACT requirement that the emission limitation be no less stringent than an applicable NSPS limit.[153]

For the emergency firewater pump (EU 12), it appears that ADEC assumes this engine will qualify as an emergency engine under the NSPS which has different (less stringent) emission limits under 40 C.F.R. Part 60, Subpart IIII. However, the Draft Permit does not include the necessary limitation for the emergency firewater pump to be considered an "emergency stationary internal combustion engine" under Subpart IIII of the NSPS. Specifically, EPA defines "emergency stationary internal combustion engine" as an engine that meets all of the following criteria:

> 1) one that is operated to provide electrical power or mechanical work during an emergency situation (when there is a lack of power or power is interrupted), or if the engine is used to pump water in the case of fire or flood;
>
> 2) the engine is operated under limited circumstances aside from emergencies, and
>
> 3) the engine operates as part of a financial arrangement with another entity in non-emergency situations.

40 C.F.R. §60.4219.

In addition, "emergency stationary internal combustion engines" must also meet the requirements specified in 40 C.F.R. §60.4211(f) to be considered an emergency engine.[154] Those detailed provisions essentially require that, to be qualified as an emergency stationary internal combustion engine, it must not be operated for any more than 100 hours per year for non-emergency situations including maintenance, testing, and emergency demand response. If operated for other non-emergency situations that do not include maintenance, testing, and emergency demand response, such operating time cannot exceed 50 hours per year.[155] However, the only limitation on operating hours for the emergency firewater pump (EU 12) that is in the Draft Permit is a 500 hour limit per 12-month period.[156] Thus, ADEC has not imposed the required limitations on operating hours in order for the firewater pump to qualify as an "emergency stationary internal combustion engine" under Subpart IIII of the NSPS. In

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[152] *See* ADEC's Preliminary September 11, 2020 TAR, Appendix B at 40, 43, 47, and 51.
*See also* Appendix A to ADEC Preliminary TAR at 1-2 (and footnote 4).

[153] *See* 40 C.F.R. §52.21(b)(12), incorporated by reference into Alaska's regulations at 18 AAC 50.040(h)(4).

[154] 40 C.F.R. §60.4211(f).

[155] *See* 40 C.F.R §60.4211(f).

[156] Draft Permit at 12.

the absence of the appropriate operating limitations to be considered an "emergency stationary internal combustion engine," the firewater pump must be required to meet BACT limits that are no less stringent that the final Tier 4 emission standards listed in Table 8 above.

If ADEC did impose operating limitations consistent with 40 C.F.R. §60.4211(f) in the PSD permit for the firewater pump, then the BACT requirements for the firewater pump must be no less stringent than the Tier 3 engine standards. Those NSPS emission standards that would apply if the emergency firewater pump's operations were limited in the permit as required by 40 C.F.R. §60.4211(f) are provided in the table below.

**Table 9. Tier 3 Emission Standards Applicable to "Emergency Stationary Internal Combustion Engines" for Engines Between 130 – 450 kW (175 – 600 hp)[157]**

| Pollutant | Limit, g/kW-hr | Limit, g/hp-hr |
|---|---|---|
| ***NOx + NMHC*** | 4.0 | 3.0 |
| ***PM*** | 0.2 | 0.15 |
| ***CO*** | 3.5 | 2.6 |

ADEC set BACT limits based on these Tier 3 standards, but ADEC increased the emission limits for all pollutants except CO by a 25% factor of safety.[158] Thus, ADEC's BACT limits for the firewater pump are less stringent than the Tier 3 emission standards listed in Table 9 above. For the same reason stated above, ADEC has no legal basis to establish BACT emission limits based on an increase in the applicable NSPS floor emission limits by a safety factor. If ADEC includes proper operational limitations in the permit for the emergency firewater pump (EU 11) to be considered an "emergency stationary internal combustion engine" under 40 C.F.R. Part 60, Subpart IIII, then the BACT limits applicable to the engine must be no less stringent than the Tier 3 engine limits listed in Table 9 above. In the absence of sufficient operational limitations to ensure that the emergency firewater pump is considered an emergency stationary internal combustion engine under the NSPS, ADEC cannot impose BACT emission limits any less stringent than the Tier 4 emission standards listed in Table 8 above for EU 11.

Moreover, given that BACT is supposed to be based on the maximum degree of emission reduction achievable and the fact that this is a new facility, ADEC should simply require that both diesel engines meet Tier 4 emission standards as BACT limits. 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).

# III. Comments on BACT for the Flares

The Alaska LNG 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

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[157] *See* 40 C.F.R. §89.112(a) Table 1. *See also* https://dieselnet.com/standards/us/nonroad.php#tier3.
[158] *See* ADEC's Preliminary September 11, 2020 TAR, Appendix B at 40, 43, 47, and 51.
*See also* Appendix A to ADEC Preliminary TAR at 1-2 (and footnote 3).

lines (EUs 14-19), and an elevated low pressure flare with maximum relief capacity of 990 Mscf/hr (EU 20).[159] AGDC describes the flaring operations in its BACT analysis of its permit application as follows:

> The LNG Plant would have three flare gas systems (i.e., wet, dry, and low-pressure), to route relief vapors from separate sections of the plant into their respective flare collection headers. The wet flare gas system would control waste gas streams containing a significant concentration of water (i.e., around the molecular sieve dehydration beds), or contain a significant concentration of heavier compounds, which could freeze out at colder temperatures (i.e., pressure relief and de-pressuring flow from the debutanizer column). The dry flare gas system would be used for safe disposal of dry hydrocarbons streams discharged downstream of the dehydration unit both under emergency condition and during a start-up condition. The low-pressure [boil-off gas (BOG)] flare gas system would be used for safe disposal of low-pressure operational releases from the LNG Storage and Loading System and intermittent maintenance purging of inert gas from LNG carriers. A thermal oxidizer would be used to control off-gas emissions from the condensate tank. Gases from storage tanks and LNG carrier loading would be captured and reused as fuel gas, where possible.

Alaska LNG Application, Attachment 6, BACT Analysis, April 30, 2018, at 45-46.

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 $SO_2$, simply reflective of EPA emission factors for flares.[160] 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 only applies 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.[161] The Draft Permit also imposes a GHG emission limit of 117.1 lb/MMBtu[162] 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).[163]

Flaring is used to dispose of gas streams when there is a disruption of the normal gas liquefaction and/or LNG transport process that disrupts the processing or transport of the gas stream. The gas stream at the Alaska LNG plant will be primarily methane, hydrocarbons, and VOCs.[164] Sulfur compounds will also be present, but only to a small degree.[165] Flares are intended to be a control device for hydrocarbons and VOCs in the vented gas. Flaring also converts methane in the vented gas to $CO_2$. Both methane and $CO_2$

[159] Draft Permit at 1 (Table 1).
[160] ADEC's Preliminary September 11, 2020 TAR, Appendix B at 64, 66, 67, 71, and 73.
[161] Draft Permit at 23 (Condition 17).
[162] *Id.*
[163] *Id.* at 24.
[164] *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").
[165] *Id.*

are greenhouse gases, but methane is a more powerful greenhouse gas.[166] EPA indicates that properly operated flares should achieve 98% destruction efficiency of VOCs.[167] However, according to EPA studies, flares can operate at a wide range of Destruction and Removal Efficiency (DRE). As a result, although flares are a VOC control device, flares are also a source of VOC emissions especially when not designed or operated in a manner to achieve high levels of DRE. Further, "[s]mall amounts of uncombusted vent gas will escape the flare combustion zone along with products of incomplete combustion,"[168] which can add to VOC emissions as well as methane emitted from the flare. Flaring of natural gas also results in emissions of NOx, as well as particulate matter emissions of carbon particles (soot) and unburned hydrocarbons. Because flaring is an open, elevated combustion source, weather conditions such as wind can also result impact the completeness of combustion of the natural gas in a flare. ADEC's BACT analysis and proposed permit limitations for flares fail to reflect BACT, as discussed below.

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

As stated above, flaring converts methane in the natural gas stream to $CO_2$. Thus, while flaring destroys one GHG pollutant, it results in the emission of another GHG pollutant. Thus, the top option to control emissions of GHG and all other pollutants emitted from flaring is to eliminate flaring by capturing the excess gas for use, rather than to flare the excess gas. One option for capture and use of excess gas is to capture the gas and route it to a pipeline to be used at other onsite or offsite combustion sources. This would allow the natural gas to be used for mechanical or electrical power, rather than the energy in the gas just simply being flared for no other beneficial use. At the Alaska LNG plant, another option for use of the excess gas when an LNG processing line is down due to upset or maintenance would be to route the natural gas to another LNG processing line so that the natural gas can be liquified and utilized, rather than just combusted in a flare. Even if just part of the excess natural gas stream could be routed to and accommodated by another LNG line, that would reduce $CO_2$, VOC, NOx and PM emissions from the flaring of the remainder of the gas stream and instead allow the gas to be processed into a usable fuel. ADEC failed to consider any capture and use requirement in its BACT analysis for flaring operations. ADEC should evaluate this option as a BACT control for all pollutants emitted by flaring.

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

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

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[166] *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why
[167] *See* EPA, Air Pollution Control Fact Sheet, Flare, EPA-452/F-03-019, *available at:* https://www3.epa.gov/ttn/catc/dir1/fflare.pdf and attached as Ex. 26.
[168] 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, at 6, *available at:* https://www.epa.gov/sites/production/files/2017-11/documents/organic_gas.pdf and attached as Ex. 27.

controlled to a much greater extent than in an open flame of an elevated flare. EPA indicates that thermal incinerators can achieve 98% to 99.9999% destruction of VOCs.[169] However, thermal incinerators typically require auxiliary fuel to preheat the waste gas and sustain the heat necessary for destruction of VOCs.[170] The high temperature reaction necessary in an incinerator to destroy the VOC and air toxic emissions can result in increased NOx emissions, but there are options to control the NOx emissions. To limit NOx emissions, low NOx burners or other low NOx processes are available control measures to integrate into the thermal incinerator.[171] The Alaska LNG plant will have a vent gas thermal oxidizer to address vented hydrocarbon emissions from the condensate storage and loading.[172] A comparison of ADEC's proposed BACT emission limits for the thermal oxidizer (EU 13) to ADEC's BACT emission limits for the flares (EU 14-20) shows how much lower VOC, CO and NOx emissions can be with a thermal oxidizer, as shown in the table below.

**Table 10. Comparison of ADEC's BACT Emission Limits for the Vent Gas Thermal Oxidizer (EU 13) to ADEC's BACT Emission Limits for the Flares (EU 14-19)**

| Pollutant | BACT Limit for Thermal Oxidizer (EU 13)[173] | BACT Limit for Flares (EU 14-20)[174] |
|---|---|---|
| VOCs | 0.0054 lb/MMBtu | 0.66 lb/MMBtu |
| CO | 0.082 lb/MMBtu | 0.31 lb/MMBtu |
| NOx | 0.055 lb/MMBtu | 0.068 lb/MMBtu |

Thus, for these reasons, ADEC should have evaluated the use of a thermal incinerator as a BACT option in lieu of flaring.

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

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.[175] 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

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[169] EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 4, *available at:* https://www3.epa.gov/ttnchie1/mkb/documents/fthermal.pdf and attached as Ex. 28.
[170] *Id. See also* EPA, Control Cost Manual, Section 3, Chapter 2 – Incinerators and Oxidizers, at 2-3 to 2-4, *available at:* https://www.epa.gov/sites/production/files/2017-12/documents/oxidizersincinerators_chapter2_7theditionfinal.pdf.
[171] *See*, e.g., Zeeco Products & Applications, Incinerators & Thermal Oxidizers Multi-Stage Low-NOx Incinerator/Thermal Oxidizer, *available at:* https://www.zeeco.com/incinerators/incinerators-therm-ox-multi-stage.php. *See also* AERON, Thermal Oxidation/Incineration Systems, Ultra-Low Emissions Systems, *available at:* http://www.aereon.com/enclosed-combustion-systems/ultra-low-emissions-systems/certified-ultra-low-emissions-burner-ceb.
[172] *Id.* at 22 (Condition 16).
[173] Draft Permit at 23-24 (Condition 17).
[174] *Id.* at 23 (Condition 17).
[175] Draft Permit at 24.

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 in that such recordkeeping and reporting provides ability for lessons to be learned from flaring events and for appropriate flaring minimizing plans to be put into place from excess flaring events. EPA has listed the following measure to prevent excess flaring at refineries, and this same approach can be used to identify methods and techniques to reduce flaring at LNG facilities:

> Conduct a root-cause analysis of each flaring incident to identify if any equipment and/or operational changes are necessary to eliminate or minimize that cause so as to reduce or avoid future flaring events. As appropriate, corrective measures should be taken and implemented. If the analysis shows that the same cause has happened before, the incident should not be considered a malfunction and corrective measures should be taken to prevent future occurrences....[176]

In addition, EPA states that "[r]edundant units can prevent flaring by allowing one unit to operate if the other needs to be shut down for maintenance or an upset. . . ."[177] Thus, adding excess capacity and/or backup units could be important in reducing the amount of flaring due to upsets.

At a minimum to address BACT for flaring emissions at the Alaska LNG plant, ADEC must require that the company's flaring minimization plan be submitted to ADEC for review and approval, and that the flaring minimization plan be updated periodically. In addition, ADEC should require in the permit that data be collected on the length of time of each flaring episode, the amount of gas flared, the cause, and the actions taken to minimize or end the flaring episode. The Draft Permit should also require that such data be reported to ADEC, so that ADEC can evaluate the root causes of upsets that cause flaring episodes to determine if measures, such as improved maintenance or duplicative parts or processing units, can be employed to reduce flaring episodes.

In addition, ADEC must specifically impose a requirement in the permit that all emission units and facilities be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Such a requirement would provide a legal requirement for ensuring minimization of flaring, which could be evaluated with required recordkeeping and reporting of all flaring events.

Moreover, ADEC should impose a limit on the total hours of flaring per rolling 12-month period due to all causes including upsets, in lieu of or in addition to an annual time limit on flaring due to startup, shutdown, and maintenance events. If that total number of flaring hours is exceeded primarily due to upsets, the permit should trigger a series of actions to determine and remedy the root causes of the flaring episodes. For example, if a compressor turbine is frequently shutting down due to malfunctions, it would trigger the need for prompt maintenance and repair. ADEC can always exercise enforcement

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[176] *See* EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, at 3 *available at:* https://www.epa.gov/sites/production/files/documents/flaring.pdf and attached as Ex. 29.
[176] 81 Fed. Reg. 83,008 (Nov. 18, 2016).
[177] *Id.*

discretion with any such annual time limit on flaring for true emergencies. However, if excess flaring is occurring due to equipment malfunctions (which would currently be considered exempt from ADEC's 500 hour flare limit per year), a time limit on total hours of flaring per rolling 12-month period would provide ADEC with an enforceable remedy to require AGDC to repair its equipment.

### D. Summary – ADEC's Proposed BACT Analysis and Limits for the Flares Are Inadequate to Ensure the Maximum Degree of Emissions Reduction from Flaring

For the reasons discussed above, ADEC's BACT analysis for vented gas disposal by flaring is inadequate. ADEC must analyze as a control option capture and use of vented gas stream as a top control option to avoid emissions from flaring. ADEC must also evaluate as a second-tier option the use of thermal incineration in lieu of flaring. Last, if after conducting analyses of those controls, flaring minimization continues the top BACT control option, ADEC must impose additional requirements in the permit to ensure that flaring is truly minimized. Such requirements include a requirement to operate the facility and all equipment in accordance with good air pollution control practices for minimizing emissions, a recordkeeping and reporting requirement for all flaring events regardless of cause, a requirement to submit and update the flaring minimization plan as needed, and a limit on total number of hours flared per rolling 12-month period to include flaring due to upsets and emergencies.

## Attachment A - Curriculum Vitae


**Victoria R. Stamper**
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Boise, Idaho 83707
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### Areas of Expertise

***Comprehensive knowledge of the Clean Air Act*** **-** accomplished in the requirements for new source review (NSR) and prevention of significant deterioration (PSD) construction permits including review of Best Available Control Technology (BACT) determinations, Title V operating permits, Maximum Achievable Control Technology (MACT) Approvals, Class I area protection including regional haze plans and best available retrofit technology (BART) determinations, and state implementation plans for compliance with the national ambient air quality standards (NAAQS).

***Extensive experience with the air pollution issues related to coal-fired and natural gas-fired power plants*** **–** have evaluated numerous PSD permit applications, best available control technology determinations, and best available retrofit technology determinations for the fossil fuel-fired electric utility industry.

### Professional Experience

Air Quality Consultant — April 2003 to Present
Boise, ID 83707

I provide consulting services on numerous air quality issues such as:

- Reviewing/preparing comments on all aspects of air quality construction and operating permit applications and permits for industrial sources including coal- and natural gas-fired power plants.
- Providing technical expertise for the appeal of air quality permits that do not comply with federal or state clean air requirements.
- Investigating facility compliance with federal and state air quality regulations.
- Analyzing proposed or available mercury and other hazardous air pollutant controls for coal-fired power plants.
- Reviewing and commenting on Class I regional haze and visibility protection plans.
- Evaluating best available retrofit technology determinations and reasonable progress controls for various source types under the Regional Haze program.
- Critiquing prevention of significant deterioration increment analyses.
- Evaluating and commenting on air quality analyses and environmental impact statements for proposed oil and gas development in the West.

**Professional Experience (continued)**

Environmental Engineer/Legal Assistant — May 2001 to April 2003
Reed Zars, Attorney at Law
Laramie, WY 82070

*Responsibilities included:*

- Investigating industrial facilities' compliance with Clean Air Act requirements through review of public documents.
- Researching pollution reduction measures and effectiveness.
- Preparing comments on proposed air quality construction and operating permits
- Reviewing and preparing written comments on proposed EPA state implementation plan approvals regarding topics such as opacity regulations, emission limit exemptions, Class I area visibility plans and permitting regulations.

New Source Review Program Manager — December 1990 to April 2001
Air and Radiation Program
U.S. Environmental Protection Agency, Region VIII
Denver, Colorado 80202

*Responsibilities included:*

- Serving as the Region VIII lead for state rules regarding the new source review and prevention of significant deterioration programs, as well as other industrial source control measures.
- Reviewing all aspects of prevention of significant deterioration increment analyses.
- Reviewing state implementation plans for consistency with requirements of Clean Air Act.
- Preparing documents to justify EPA approval or disapproval of state submittals.
- Educating and assisting tribes in developing regulations for tribal implementation plans.
- Participating in workgroups to ensure national consistency and provide input on rulemakings.
- Reviewing state operating permit programs under Title V of the Clean Air Act.
- Researching and compiling the EPA-approved state implementation plans.
- Developing and reviewing state implementation plans for particulate matter nonattainment areas, as well as assisting in the preparation of requests to redesignate to attainment.
- Reviewing environmental impact statements for consistency with the Clean Air Act.
- Serving as primary contact for air quality issues in the state of Wyoming.

**Professional Experience (continued)**

Environmental Engineer — August 1989- July 1990
Envirometrics, Inc.
Seattle, Washington 98103

*Responsibilities included:*

- Designing components of research projects pertaining to pollution control systems.
- Developing testing criteria and measuring the effectiveness of these control systems.
- Preparing air pollution permit applications and related documentation for industrial sources.
- Compiling input data for modeling of ambient air quality impacts on Class I areas.
- Developing emission inventories.

## Education

Bachelor of Science Degree
Civil Engineering, Michigan State University
East Lansing, Michigan

**Selected Reports and Papers**

- Stamper, V, Comments on Company Submittals to the Utah Division of Air Quality on Air Pollution Controls to Make Reasonable Progress Towards the National Visibility Goal, October 28, 2020.

- Stamper, V. & M. Williams, Assessment of Cost Effectiveness Analyses for Controls Evaluated in Four-Factor Analyses for Oil and Gas Facilities for the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period, July 2, 2020.

- Stamper, V. & M. Williams, Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, and Flaring and Incineration, March 6, 2020.

- Stamper, V., Reasonable Progress Analysis for Nitrogen Oxide Pollution Control Upgrades at San Juan Generating Station Units 1 and 4 and at Escalante Generating Station, December 18, 2019.

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