DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL CONSTRUCTION PERMIT

Construction Permit: AQ1524CPT01 **Final Date – August 13, 2020**

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Construction Permit AQ1524CPT01 to the Permittee listed below.

Permittee:	**Alaska Gasline Development Corporation** 3201 C Street, Suite 200 Anchorage, AK 99503
Stationary Source:	**Gas Treatment Plant**
Location:	Prudhoe Bay, Alaska Latitude: 70.3199° North; Longitude: 148.5573° West
Project:	Gas Treatment Plant Construction
Permit Contact:	Frank Richards (907) 330-6352 FRichards@agdc.us

This permit is classified under 18 AAC 50.306 as a Prevention of Significant Deterioration (PSD) major stationary source for oxides of nitrogen (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM), particulate matter with an aerodynamic diameter not exceeding a nominal 10 micrometers (PM-10), particulate matter with an aerodynamic diameter not exceeding a nominal 2.5 micrometers (PM-2.5), volatile organic compounds (VOC), and greenhouse gases (GHG). The project is also classified under 18 AAC 50.316 as a major source of Hazardous Air Pollutants (HAPs) for formaldehyde and ethylbenzene.

This permit satisfies the obligation of the Permittee to obtain a construction permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

Aaron Simpson

for: James R. Plosay, Manager
Air Permits Program

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Abbreviations and Acronyms

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AAAQS	Alaska Ambient Air Quality Standard(s)
AOS	Air Online Services
AS	Alaska Statutes
ASTM	American Society for Testing and Materials
BACT	best available control technology
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data Reporting Interface
C.F.R.	Code of Federal Regulations
CAA	Clean Air Act
CO	carbon monoxide
Department	Alaska Department of Environmental Conservation
dscf	dry standard cubic foot
EPA	US Environmental Protection Agency
EU	emissions unit
FEM	Federal Equivalent Method
gr/dscf	grain per dry standard cubic foot (1 pound = 7000 grains)
gph	gallons per hour
GTP	Gas Treatment Plant
HAPs	hazardous air pollutants [as defined in AS 46.14.990]
HP	High Pressure
kPa	kiloPascals
LP	Low Pressure
MACT	maximum achievable control technology [as defined in 40 C.F.R. 63]
MMBtu/hr	million British thermal units per hour
MMscf	million standard cubic feet
MR&R	monitoring, recordkeeping, and reporting
Mscf	thousand standard cubic feet
NESHAPs	National Emission Standards for Hazardous Air Pollutants [as contained in 40 C.F.R. 61 and 63]
NOx	nitrogen oxides
NO_2	nitrogen dioxide
NRE	nonroad engine
NSPS	New Source Performance Standards [as contained in 40 C.F.R. 60]
O & M	operation and maintenance
O_2	oxygen
PM-10	particulate matter less than or equal to a nominal 10 microns in diameter
PM-2.5	particulate matter less than or equal to a nominal 2.5 microns in diameter
ppm	parts per million
ppmv, ppmvd	parts per million by volume on a dry basis
psia	pounds per square inch (absolute)
PSD	prevention of significant deterioration
PTE	potential to emit
QAPP	Quality Assurance Project Plan
QA/QC	Quality Assurance/Quality Control
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SPC	Standard Permit Condition or Standard Operating Permit Condition
SO_2	sulfur dioxide
tpy	tons per year
ULSD	Ultra-Low Sulfur Diesel
VOC	volatile organic compound [as defined in 40 C.F.R. 51.100(s)]
vol%	volume percent
WHRU	waste heat recovery unit
wt%	weight percent
wt%S_{fuel}	weight percent of sulfur in fuel
$\mu g/m^3$	micrograms per cubic meter

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to install and operate the EUs listed in Table 1 in accordance with the terms and conditions of this permit. The information in Table 1 is for identification purposes only, unless otherwise noted in the permit. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1: EU Inventory

EU #	EU Description	Fuel	Rating/Max Capacity
1	Cogeneration Treated Gas Compressor Turbine (Train 1a)	Fuel Gas	386[1] MMBtu/hr
2	Cogeneration Treated Gas Compressor Turbine (Train 1b)	Fuel Gas	386[1] MMBtu/hr
3	Cogeneration Treated Gas Compressor Turbine (Train 2a)	Fuel Gas	386[1] MMBtu/hr
4	Cogeneration Treated Gas Compressor Turbine (Train 2b)	Fuel Gas	386[1] MMBtu/hr
5	Cogeneration Treated Gas Compressor Turbine (Train 3a)	Fuel Gas	386[1] MMBtu/hr
6	Cogeneration Treated Gas Compressor Turbine (Train 3b)	Fuel Gas	386[1] MMBtu/hr
7	Cogeneration Byproduct CO_2 Compressor Turbine (Train 1a)	Fuel Gas	291[1] MMBtu/hr
8	Cogeneration Byproduct CO_2 Compressor Turbine (Train 1b)	Fuel Gas	291[1] MMBtu/hr
9	Cogeneration Byproduct CO_2 Compressor Turbine (Train 2a)	Fuel Gas	291[1] MMBtu/hr
10	Cogeneration Byproduct CO_2 Compressor Turbine (Train 2b)	Fuel Gas	291[1] MMBtu/hr
11	Cogeneration Byproduct CO_2 Compressor Turbine (Train 3a)	Fuel Gas	291[1] MMBtu/hr
12	Cogeneration Byproduct CO_2 Compressor Turbine (Train 3b)	Fuel Gas	291[1] MMBtu/hr
13	WHRU Supplemental Firing Burner – Treated Gas (Train 1a)	Fuel Gas	190[1] MMBtu/hr
14	WHRU Supplemental Firing Burner – Treated Gas (Train 1b)	Fuel Gas	190[1] MMBtu/hr
15	WHRU Supplemental Firing Burner – Treated Gas (Train 2a)	Fuel Gas	190[1] MMBtu/hr
16	WHRU Supplemental Firing Burner – Treated Gas (Train 2b)	Fuel Gas	190[1] MMBtu/hr
17	WHRU Supplemental Firing Burner – Treated Gas (Train 3a)	Fuel Gas	190[1] MMBtu/hr
18	WHRU Supplemental Firing Burner – Treated Gas (Train 3b)	Fuel Gas	190[1] MMBtu/hr
19	WHRU Supplemental Firing Burner – CO_2 (Train 1a)	Fuel Gas	140[1] MMBtu/hr
20	WHRU Supplemental Firing Burner – CO_2 (Train 1b)	Fuel Gas	140[1] MMBtu/hr
21	WHRU Supplemental Firing Burner – CO_2 (Train 2a)	Fuel Gas	140[1] MMBtu/hr
22	WHRU Supplemental Firing Burner – CO_2 (Train 2b)	Fuel Gas	140[1] MMBtu/hr
23	WHRU Supplemental Firing Burner – CO_2 (Train 3a)	Fuel Gas	140[1] MMBtu/hr
24	WHRU Supplemental Firing Burner – CO_2 (Train 3b)	Fuel Gas	140[1] MMBtu/hr
25	Simple Cycle Power Generation Combustion Turbine	Fuel Gas	386[1] MMBtu/hr
26	Simple Cycle Power Generation Combustion Turbine	Fuel Gas	386[1] MMBtu/hr
27	Simple Cycle Power Generation Combustion Turbine	Fuel Gas	386[1] MMBtu/hr
28	Simple Cycle Power Generation Combustion Turbine	Fuel Gas	386[1] MMBtu/hr
29	Simple Cycle Power Generation Combustion Turbine	Fuel Gas	386[1] MMBtu/hr
30	Simple Cycle Power Generation Combustion Turbine	Fuel Gas	386[1] MMBtu/hr
31	Building Heat Medium Heater	Fuel Gas	275[1] MMBtu/hr
32	Building Heat Medium Heater	Fuel Gas	275[1] MMBtu/hr
33	Building Heat Medium Heater	Fuel Gas	275[1] MMBtu/hr
34	Buyback Gas Bath Heater 1	Fuel Gas	25[1] MMBtu/hr
35	Buyback Gas Bath Heater 2	Fuel Gas	21[1] MMBtu/hr
36	Operations Camp Heater 1	Fuel Gas	32[1] MMBtu/hr
37	Operations Camp Heater 2	Fuel Gas	32[1] MMBtu/hr
38	Operations Camp Heater 3	Fuel Gas	32[1] MMBtu/hr
39	Black Start Generator Engine	ULSD	4,060 hp
40	Main Firewater Pump Engine 1	ULSD	250 hp
41	Main Firewater Pump Engine 2	ULSD	250 hp

EU #	EU Description	Fuel	Rating/Max Capacity
42	Main Firewater Pump Engine 3	ULSD	250 hp
43	Dormitory Emergency Generator Engine	ULSD	335 hp
44	Communications Tower Emergency Generator Engine	ULSD	200 hp
45	HP Hydrocarbon Flare – East	Fuel Gas @ pilot/purge, Process Gas to nominal capacity	76,000[2] Mscf/hr
46	HP Hydrocarbon Flare – West		76,000[2] Mscf/hr
47	LP Hydrocarbon Flare – East		4,200[3] Mscf/hr
48	LP Hydrocarbon Flare – West		4,200[3] Mscf/hr
49	HP Byproduct (CO_2) Flare – East		9,500[4] Mscf/hr
50	HP Byproduct (CO_2) Flare – West		9,500[4] Mscf/hr
51	LP Byproduct (CO_2) Flare – East		29,000[5] Mscf/hr
52	LP Byproduct (CO_2) Flare – West		29,000[5] Mscf/hr
53	Diesel Fuel Storage Tank	ULSD	19,500 gallons
54	Diesel Fueling Station Storage Tank	ULSD	450 gallons
55	Dormitory Emergency Diesel Generator Day Storage Tank	ULSD	200 gallons
56	Essential Diesel Generator Day Storage Tank	ULSD	3,600 gallons
57	Firewater Diesel Day Tank #1	ULSD	350 gallons
58	Firewater Diesel Day Tank #2	ULSD	350 gallons
59	Firewater Diesel Day Tank #3	ULSD	350 gallons
60	Communication Tower Diesel Generator Tank	ULSD	300 gallons
61	Gasoline Storage Tank	Gasoline	10,000 gallons

Table Notes:

[1] The capacity listed for EUs 1 through 38 reflects the rating for each unit at the yearly average ambient temperature for the Gas Treatment Plant of 10°F in terms of heat input.

[2] The 76,000 Mscf/hr capacity listed for EUs 45 & 46 reflects the maximum flaring event. The pilot and purge rate for these EUs is 7.3 Mscf/hr, per unit.

[3] The 4,200 Mscf/hr capacity listed for EUs 47 & 48 reflects the maximum flaring event. The pilot and purge rate for these EUs is 1.3 Mscf/hr, per unit.

[4] The 9,500 Mscf/hr capacity listed for EUs 49 & 50 reflects the maximum flaring event. The pilot and purge rate for these EUs is 2.7 Mscf/hr, per unit.

[5] The 29,000 Mscf/hr capacity listed for EUs 51 & 52 reflects the maximum flaring event. The pilot and purge rate for these EUs is 6.3 Mscf/hr, per unit.

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

2. The Permittee shall commence[1] construction of the stationary source authorized under Construction Permit AQ1524CPT01 within 18 months of the issuance of the permit[2] unless granted an extension in writing from the Department.

[1] Commence has the meaning given in 40 C.F.R. 52.21(b)(9).
[2] See: 40 C.F.R. 52.21(r)

Section 2 Fee Requirements

3. **Administration Fees.** The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-420.

4. **Assessable Emissions**. The Permittee shall pay to the Department annual emission fees based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410.[3] The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities 10 tons per year or greater. The quantity for which fees will be assessed is the lesser of:

   4.1 the stationary source's assessable potential to emit of 27,415 tpy; or

   4.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:

      a. an enforceable test method described in 18 AAC 50.220;

      b. material balance calculations;

      c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035;

      d. other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.

5. **Assessable Emission Estimates.** Emission fees will be assessed as follows:

   5.1 no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions via the Department's AOS System at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option and filling out the Emission Fee Estimate form. Alternatively, the report may be submitted by:

      a. Email under a cover letter using dec.aq.airreports@alaska.gov; or

      b. hard copy to the following address: ADEC Air Permits Program, ATTN: Assessable Emissions Estimate, 555 Cordova Street, Anchorage, Alaska 99501.

   5.2 The Permittee shall include with the assessable emissions report all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates.

   5.3 If no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set out in Condition 4.1.

[3] If the stationary source has not commenced construction or operation on or before March 31st, submit a transmittal letter certified under 18 AAC 50.205 to the Department's Anchorage office, in accordance with Condition 5.1, that identifies the source's assessable emissions for the previous fiscal year to be zero tons per year and provide estimates for when construction and operation will commence.

Section 3 State Emission Standards

6. **Visible Emissions for Industrial Process and Fuel-Burning Equipment.** The Permittee shall not cause or allow visible emissions (VE), excluding condensed water vapor, emitted from EUs 1 through 52, to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

   6.1 For EUs 39 through 44, perform an initial Method 9 observation within 60 days of initial startup of each EU.

      a. Record the date of initial startup of EUs 39 through 44.

      b. Report the results of the Method 9 observations required by Condition 6.1 and the date of initial startup required by Condition 6.1a in the first operating report due after the observations were performed, as required under Condition 25.

   6.2 For EUs 1 through 38, burn only fuel gas as fuel. Monitoring for these EUs shall consist of a statement in each operating report required under Condition 25 that each of these EUs fired only fuel gas as fuel. Report under Condition 24 if any fuel other than fuel gas is burned.

   6.3 For EUs 45 through 52, perform an initial Method 9 observation during the initial daylight flare event.[4] If no event exceeds one hour then the Permittee shall observe the next daylight flare event.

      a. Monitor the flare for visible emissions for 18 minutes during flare events using Method 9.

      b. Record the following information for observed events:

         (i) the flare(s) EU ID number;

         (ii) results of the Method 9 observations;

         (iii) reason(s) for flaring;

         (iv) date, beginning and ending time of event; and

         (v) volume of fuel gas and produced gas flared.

      c. Monitoring of a flare event may be postponed for safety or weather reasons, or because a qualified observer is not available. If monitoring of a flare event is postponed for any of the reasons described in this condition, the Permittee shall include in the next operating report required by Condition 25 an explanation of the reason the event was not monitored.

      d. Attach copies of the records required by Condition 6.3b in the first operating

[4] For purposes of this permit, a flare event is flaring of fuel gas and produced gas for greater than one hour as a result of scheduled release operations, i.e. maintenance. It does not include non-scheduled release operations, i.e. process upsets, emergency flaring, or de-minimis venting of gas incidental to normal operations.

report due after the observations were performed, as required under Condition 25.

6.4 Report as excess emissions and permit deviation under Condition 24 whenever the opacity standard in Condition 6 is exceeded or if any of Conditions 6.1 through 6.3 are not met.

7. **Particulate Matter for Industrial Process and Fuel-Burning Equipment.** The Permittee shall not cause or allow particulate matter emitted from EUs 1 through 52, to exceed 0.05 grains per dry standard cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

7.1 For EUs 39 through 44, obtain a certified manufacturer's guarantee that the EUs will comply with the particulate matter standard, within 60 days of startup; or

7.2 Demonstrate compliance with the PM standard by complying with Condition 6.1.

8. **Sulfur Compound Emissions.** The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EUs 1 through 52 to exceed 500 parts per million (ppm) averaged over three hours. Demonstrate compliance with the SO_2 standard by complying with Conditions 11.1 and 11.2.

Section 4 Ambient Air Quality Protection Requirements

9. The Permittee shall construct and operate the stationary source as described below in order to protect the 1-hour and annual NO_2; 24-hour PM-10; 24-hour and annual PM-2.5; 1-hour and 8-hour CO; and 1-hour, 3-hour, 24-hour, and annual SO_2 AAAQS; and the annual NO_2; 24-hour and annual PM-10; and 24-hour and annual PM-2.5 maximum allowable increases (increments) for Class II areas:

9.1 **Stack Configuration for Temporary Camp Engines.** Construct and maintain vertical, uncapped exhaust stacks for all reciprocating engines used to provide electrical power to the temporary GTP construction camps. This condition does not preclude the use of flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

a. Include in each operating report required by Condition 25:

(i) A statement that the temporary camp engine exhaust stacks comply with Condition 9.1, or

(ii) A statement that no temporary camp engines were operated during the reporting period.

b. Report as described in Condition 24 if a requirement under Condition 9.1 was not met.

9.2 **Stack Configuration for Heaters and Engines.** Construct and maintain vertical, uncapped exhaust stacks for EUs 31 through 44. This condition does not preclude the use of flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

a. Include in the first operating report required by Condition 25 that would be due after the installation of an EU listed in Condition 9.2, a statement that the exhaust stack for that EU complies with Condition 9.2.

b. Report as described in Condition 24 if a requirement under Condition 9.2 was not met.

9.3 **Stack Height Requirements.** Construct and maintain the exhaust/flare stack heights, as applicable, for the EUs listed in Table 2 so that the height above pad surface equals or exceeds the minimum height listed for that EU. For EUs 1 through 12, the stack height requirement applies to both the waste heat recovery units (WHRU) bypass stack and the WHRU stack (i.e., the stacks with EUs 13 through 24).

Table 2: Minimum Stack Height Requirements

EU	Description	Min. Height (m)
1 - 6	Treated Gas Compressors	73.15
7 – 12	Byproduct (CO_2) Compressors	73.15
25 – 30	Combustion Turbine Generators	73.15
31 – 33	Building Heat Medium Heaters	70.71
36 – 38	Operations Camp Heaters	9.75
39	Black Start Generator Engine	35.05
45 – 48	Hydrocarbon Flares	65.00
49 – 52	Byproduct (CO_2) Flares	65.00

a. Provide as-built drawings and photographs of each exhaust/flare stack listed in Table 2 in the first operating report required by Condition 25 that would be due after installation of the given EU.

b. Report as described in Condition 24 if a requirement under Condition 9.3 was not met.

9.4 **Concurrent Operating Limits.**

a. Limit the concurrent operation of EUs 31 through 33 to no more than two units at a time, except during startup, shutdown, and maintenance activities for periods not to exceed one hour per day.

b. Limit the concurrent operation of EUs 36 through 38 to no more than two units at a time, except during startup, shutdown, and maintenance activities for periods not to exceed one hour per day.

c. Record the startup and shutdown times for each day of operation for each of EUs 31 through 33 and 36 through 38, and the reason for operating.

d. If all three of EUs 31 through 33 are operated concurrently during a reporting period, include the length of time and reason for concurrent operation in the operating report required by Condition 25.

e. If all three of EUs 36 through 38 are operated concurrently during a reporting period, include the length of time and reason for concurrent operation in the operating report required by Condition 25.

f. Report as described in Condition 24 if a requirement under Condition 9.4 was not met.

10. **Fugitive Particulate Matter Control Requirements.** The Permittee shall protect the 24-hour PM-10, the 24-hour PM-2.5, and the annual PM-2.5 AAAQS while constructing the stationary source by complying with Conditions 10.1 and 10.2 below.

10.1 **Fugitive Dust Control.** During each May, June, July, August, and September, the Permittee shall limit fugitive dust emissions within the GTP project area and nearby gravel mine by applying water/chemical suppressants to the dust emitting surfaces, or by reducing the dust-generating activity, as needed.

Monitor, record, and report as follows:

a. Except as allowed under Condition 10.1b, perform a daily inspection of the active construction areas to determine whether abatement is needed. Require abatement whenever a visible plume of dust has an estimated opacity that exceeds 20 percent at 300 feet or more from the source.

b. The daily inspections required under Condition 10.1a may be suspended on days with measurable precipitation, or on days with no dust-generating construction activities.

c. Record the location, observed activity, and fugitive dust observations of each inspection in a daily log. Record whether abatement was required, and if so, the action that was taken. Note whenever the daily inspections were suspended, as allowed under Condition 10.1b, and if so, why.

d. Record all fugitive dust complaints received by the Permittee, or by the Department and conveyed to the Permittee, utilizing the complaint form in Section 10. Record how the complaint was addressed/resolved.

e. Provide a copy of all fugitive dust complaints recorded under Condition 10.1d to the Department within 30 days of receiving the complaint.

f. Report any abatement actions performed under Condition 10.1 in the operating reports required by Condition 25.

g. Report as described in Condition 24 if a requirement under Condition 10.1 was not met.

10.2 **Ambient Air Monitoring**. The Permittee shall establish ambient PM-10 and PM-2.5 monitoring during the construction phase as follows:

a. At least 180 days prior to commencing construction, submit for Department approval a scaled site map(s) that identifies the proposed locations of one or more downwind PM-10 monitoring site and one or more downwind PM-2.5 monitoring site.[5] Site the monitoring stations in areas that would likely experience the maximum construction-related 24-hour PM-10 and 24-hour PM-2.5 impacts from the GTP project area and nearby gravel mine. Include a written narrative that documents the reasons for selecting the proposed monitoring sites.

b. Within 60 days of the Department's approval of the monitoring locations, submit for Department approval a QAPP for the PM-10/PM-2.5 monitoring

[5] Provide a copy of the monitoring locations proposed under Condition 10.2a to the Permit Intake Clerk in the Department's Anchorage office at 555 Cordova Street, Anchorage, Alaska 99501.

effort.[6] The QAPP shall describe the procedures that the Permittee intends to use in order to:

(i) Collect continuous data using FEM continuous monitors;

(ii) Collect data that complies with 18 AAC 50.215(a);

(iii) Obtain data that meet the PSD program QA/QC requirements, including a data capture rate of 80 percent per quarter; and

(iv) Comply with Conditions 10.2c through 10.2e.

c. The Permittee shall initiate their monitoring program prior to beginning onsite construction. Once initiated, monitoring shall continue to occur year-round, throughout the GTP construction phase.

(i) The Permittee may temporarily suspend the monitoring program for a designated period, with written Department approval, during a long-term suspension of all fugitive dust generating construction activities.

(ii) The Permittee may permanently end the monitoring program, with written Department approval, once they have demonstrated to the Department's satisfaction that the fugitive dust generating construction activities have been completed, or upon commissioning[7] of EUs 1 through 33.

d. The Permittee shall establish a manual or automated system that continuously reviews the PM-10 and PM-2.5 monitoring data so that the following actions may be promptly taken during elevated readings:

(i) If the measured PM-10 concentration exceeds 250 $\mu g/m^3$ but remains below 500 $\mu g/m^3$ during a 1-hour averaging period, or exceeds 75 $\mu g/m^3$ but remains below 100 $\mu g/m^3$ during a 24-hour averaging period, the permittee shall:

(A) Determine what emission activities are likely causing these elevated concentrations;

(B) Monitor the weather forecast, and actual wind speed and direction data from the Deadhorse National Weather Service office, in order to predict the likely need for reducing on-site PM-10 emissions; and

[6] Provide a copy of the QAPP proposed under Condition 10.2b to the Permit Intake Clerk in the Department's Anchorage office.

[7] For the purpose of this permit, commissioning of EUs 1 through 33 includes the initial mechanical acceptance of process equipment and electric generating equipment, for a period of time not to exceed 90 days from initial startup of the first EU.

(C) Take the preparatory actions needed to promptly reduce on-site fugitive dust emissions, if such action is subsequently required under Condition 10.2d(ii).

(ii) If the measured PM-10 concentration exceeds 500 $\mu g/m^3$ during a 1-hour averaging period, or 100 $\mu g/m^3$ during a 24-hour averaging period, the Permittee shall take one or more of the following actions as needed to reduce the measured concentrations or to document the off-site source of the elevated concentrations:

(A) Inspect the immediate vicinity of the monitor(s) for possible causes of the elevated readings, and if warranted, take appropriate abatement action;

(B) Apply focused chemical and/or water treatment or other corrective actions in the active construction areas that are potentially contributing to the elevated PM-10 concentrations;

(C) If necessary, temporarily realign or suspend the construction activities that are likely causing or substantially contributing to these measured concentrations; and/or

(D) If the elevated concentrations appear to be due to natural events, such as wildfire, document the basis for reaching that conclusion, and note whether fugitive dust emissions are being properly controlled.

(iii) If the measured PM-2.5 concentration exceeds 60 $\mu g/m^3$ but remains below 120 $\mu g/m^3$ during a 1-hour averaging period, or exceeds 15 $\mu g/m^3$ but remains below 25 $\mu g/m^3$ during a 24-hour averaging period, the permittee shall:

(A) Determine what emission activities are likely causing these elevated concentrations;

(B) Monitor the weather forecast, and actual wind speed and direction data from the Deadhorse National Weather Service office, in order to predict the likely need for reducing on-site PM-2.5 emissions; and

(C) Take the preparatory actions needed to promptly reduce on-site fugitive dust emissions, if such action is subsequently required under Condition 10.2d(iii).

(iv) If the measured PM-2.5 concentration exceeds 120 $\mu g/m^3$ during a 1-hour averaging period, or 25 $\mu g/m^3$ during a 24-hour averaging period, the Permittee shall take one or more of the following actions as needed to reduce the measured concentrations or to document the off-site source of the elevated concentrations:

(A) Inspect the immediate vicinity of the monitor(s) for possible causes of the elevated readings, and if warranted, take appropriate abatement action;

(B) Apply focused chemical and/or water treatment or other corrective actions in the active construction areas that are potentially contributing to the elevated PM-2.5 concentrations;

(C) If necessary, temporarily realign or suspend the construction activities that are likely causing or substantially contributing to these measured concentrations; and/or

(D) If the elevated concentrations appear to be due to natural events, such as wildfire, document the basis for reaching that conclusion, and note whether fugitive dust emissions are being properly controlled.

(v) Notify the Department in accordance with Condition 21 within 24-hours of any actions taken under Condition 10.2d(ii) or if any:

(A) 24-hour average PM-10 concentration exceeds 150 µg/m3,

(B) 24-hour average PM-2.5 concentration exceeds 35 µg/m3, or

(C) Annual average PM-2.5 concentration exceeds 12 µg/m3.

(vi) Report in the operating report required under Condition 25, any actions taken under Condition 10.2d(i), 10.2d(ii), 10.2d(iii), or 10.2d(iv), including mitigative measures taken.

e. Submit annual monitoring reports for Department review and approval as follows:

(i) The monitoring reports shall be submitted no later than 60 days after a block 12-month monitoring period ends;

(ii) Provide a copy of the reports specified in Condition 10.2e to the Permit Intake Clerk in the Department's Anchorage office.

f. Report as described in Condition 24 whenever a measured concentration of PM-10 or PM-2.5 exceed the values listed in Condition 10.2d(v)(A) through 10.2d(v)(C), or if a requirement under Condition 10.2 is not met.

11. **Fuel Sulfur Limits**. To protect the 1-hour, 3-hour, 24-hour, and annual SO_2 AAAQS, and the 3-hour, 24-hour, and annual SO_2 Class II increments, the Permittee shall:

11.1 Combust only diesel fuel that meets the ULSD specifications (i.e., less than 0.0015 percent sulfur by weight) in EUs 39 through 44.

Monitor, record, and report as follows:

a. Obtain and keep certified receipts from fuel suppliers that confirms that all diesel fuel combusted in EUs 39 through 44 meets the specifications of ULSD.

b. Report in each operating report required by Condition 25, a statement indicating whether all fuel combusted in EUs 39 through 44 during the reporting period was ULSD.

c. Report as described in Condition 24 if:

(i) fuel combusted in EUs 39 through 44 exceeds the ULSD specifications; or

(ii) Conditions 11.1a or 11.1b are not met.

11.2 Limit the total sulfur content of the fuel gas fired in EUs 1 through 38 and 45 through 52 to no more than 96 ppmv.

Monitor, record, and report as follows:

a. Analyze a representative sample of the fuel burned by EUs 1 through 38 and 45 through 52, at least monthly to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

b. A current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel does not exceed the limit in Condition 11.2.

c. Keep records of the sulfur content analysis required under Condition 11.2a, or records specifying the maximum total sulfur content of the fuel required under Condition 11.2b.

d. Include copies of the records required by Condition 11.2c with the operating report required by Condition 25 for the period covered by the report.

e. Report as excess emissions in accordance with Condition 24, whenever the sulfur content of the fuel gas fired in EUs 1 through 38 and 45 through 52, exceed 96 ppmv.

12. To protect the 1-hour and annual NO_2 AAAQS, the 1-hour and annual SO_2 AAAQS, the annual PM-2.5 AAAQS, the annual NO_2 Class II increment, the annual SO_2 Class II increment, the annual PM-10 Class II increment, and the annual PM-2.5 Class II increment, the Permittee shall limit the operation of EUs 39 through 44 to no more than 500 hours each, in any 12 consecutive month period. Monitor, record, and report in accordance with Conditions 15.2a(i) through 15.2a(iv). Report as described in Condition 24 if any of EUs 39 through 44 exceed 500 hours in any 12 consecutive month period, or if a requirement under Condition 15.2a is not met.

Section 5 Best Available Control Technology

13. **Compressor Turbines BACT Emission Limits:** Limit the emissions from the compressor turbines EUs 1 through 12 (including corresponding supplemental firing duct burners EUs 13 through 24) as specified in Table 3:

Table 3: Compressor Turbines (EUs 1 through 24) – BACT Limits

Pollutant	BACT Control	BACT Emission Limits
NOx	Dry Low NOx Good Combustion Practices	17 ppmvd at 15% O_2
CO	Oxidation Catalyst Good Combustion Practices	5 ppmvd at 15% O_2
PM, PM-10, and PM-2.5	Clean Fuel Good Combustion Practices	0.0063 lb/MMBtu[1]
SO_2	Clean Fuel Good Combustion Practices	Burn gas with total sulfur content of ≤ 96 ppmv, dropping to ≤ 16 ppmv once the three treatment trains are operational
VOC	Oxidation Catalyst Good Combustion Practices	0.0022 lb/MMBtu[1]
GHG	Clean Fuel Good Combustion Practices	117.1 lb/MMBtu[1]

1. Emission limits are based on heat input in MMBtu/hr.

13.1 For EUs 1 through 24, the Permittee shall:

a. Install, operate, and maintain dry low NOx burners and catalytic oxidation emissions controls on EUs 1 through 24, according to the manufacturer's specifications, at all times the units are operating, except for short periods of startup, shutdown, and malfunction.

b. During periods of startup, shutdown, and malfunction operate EUs 1 through 24 according to manufacturer's specifications and good combustion practices.

c. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures.

d. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

e. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

13.2 To show compliance with the NOx emission limit set out in Table 3, the Permittee shall:

a. Submit to the Department vendor verification that the cogeneration turbines will comply with the NOx limit in Table 3 at least 60 days before startup of any of EUs 1 through 12.

b. Conduct an initial source test in accordance with Section 8 on at least two of EUs 1 through 6 and at least two of EUs 7 through 12,[8] within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of the turbine, to demonstrate initial compliance with the NOx limit listed in Table 3 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU with the corresponding supplemental firing duct burner operating. One load must be within plus or minus 25 percent of 100 percent of peak load. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 3.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 40.

13.3 To show compliance with the CO and VOC emission limits set out in Table 3, the Permittee shall:

a. Submit to the Department vendor verification that the catalytic oxidation control system will comply with the CO and VOC limits established in Table 3 at least 60 days before startup of any of EUs 1 through 12.

b. Conduct an initial source test in accordance with Section 8 on two of EUs 1 through 6 and two of EUs 7 through 12, within 180 days from the first of EUs 1 through 12 beginning operation, to demonstrate initial compliance with the CO and VOC limits listed in Table 3 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU with the corresponding supplemental firing duct burner operating.

[8] 40 C.F.R. 60 Subpart KKKK requires initial and annual performance testing on each turbine subject to the new source performance standards of Subpart KKKK unless a waiver is granted by EPA.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 3.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 40.

c. Monitor the oxidation catalyst operating parameters as follows:

(i) Install temperature sensing devices to monitor the inlet air temperature of each installed oxidation catalyst.

(A) Monitor exhaust temperature at the inlet to each oxidation catalyst unit at least once per hour during all periods of operation. Record for each calendar day the minimum and maximum inlet gas temperature of each oxidation catalyst unit. Data capture and recording may be electronic.

(B) Report the minimum and maximum daily inlet gas temperature of each oxidation catalyst unit for each calendar month in the operating report required by Condition 25.

(ii) Install gauges before and after the oxidation catalyst controls to monitor the pressure drop across each installed oxidation catalyst unit.

(A) Maintain the oxidation catalyst such that the pressure drop across each oxidation unit is within the acceptable range identified in the manufacturer's specifications, or within the range determined by the most recent source tests under Conditions 13.2b(iv), 13.3b(iv), and 13.4b(iv).

(B) If the pressure drop exceeds the acceptable differential identified in the manufacturer's specifications, the oxidation catalyst unit shall be inspected, cleaned, or replaced, as necessary.

13.4 To show compliance with the PM, PM-10, and PM-2.5 emission limits set out in Table 3, the Permittee shall:

a. Submit to the Department, a certified manufacturer's guarantee demonstrating that EUs 1 through 12 will comply with the emission limits in Table 3 at least 60 days before startup of any of EUs 1 through 12; or

b. Conduct an initial source test in accordance with Section 8, on two of EUs 1 through 6 and two of EUs 7 through 12 within 180 days from the first of EUs 1 through 12 beginning operation to demonstrate initial compliance with the PM, PM-10, and PM-2.5 limits listed in Table 3 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU with the corresponding supplemental firing duct burner operating.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu.

(iv) During each test run, measure the inlet air temperature and pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 40.

13.5 To show compliance with the SO_2 emission limit set out in Table 3, the Permittee shall:

a. Monitor, record, and report in accordance with Condition 11.2.

b. Maintain good combustion practices at all times the units are in operation.

c. Upon completion of the third natural gas treatment train, limit the total sulfur content of the fuel gas fired in EUs 1 through 24 to no more than 16 ppmv. Once triggered; monitor, record, and report as follows:

(i) Notify the Department of the completed third natural gas treatment train in the first operating report required by Condition 25 that would be due after the third natural gas treatment train becomes operational.

(ii) Analyze a representative sample of the fuel burned by EUs 1 through 24 at least monthly to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

(iii) A current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel does not exceed the limit in Condition 13.5c.

(iv) Keep records of the sulfur content analysis required under Condition 13.5c(ii), or records specifying the maximum total sulfur content of the fuel required under Condition 13.5c(iii).

(v) Include copies of the records required by Condition 13.5c(iv) with the operating report required by Condition 25 for the period covered by the report.

(vi) Report as excess emissions in accordance with Condition 24, whenever the sulfur content of the fuel gas fired in EUs 1 through 24 exceeds 16 ppmv.

13.6 To show compliance with the GHG emission limit set out in Table 3, the Permittee shall:

a. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

b. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

c. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

13.7 Report as described in Condition 24 if:

a. any of the emission rates determined by the source tests required by Conditions 13.2 through 13.4 exceed the limits in Table 3;

b. the inlet gas temperature of an oxidation catalyst unit is outside the acceptable range identified in the manufacturer's specifications, or outside the range determined by the most recent source tests under Conditions 13.2b(iv), 13.3b(iv), and 13.4b(iv);

c. the pressure drop across an oxidation catalyst unit is outside the acceptable range identified in the manufacturer's specifications, or outside the range determined by the most recent source tests under Conditions 13.2b(iv), 13.3b(iv), and 13.4b(iv); or

d. Conditions 13.1 through 13.6 are not met.

14. **Power Generation Turbines BACT Emission Limits:** Limit the emissions from the simple cycle power generation turbines EUs 25 through 30 as specified in Table 4:

Table 4: Power Generation Turbines (EUs 25 through 30) – BACT Limits

Pollutant	BACT Control	BACT Emission Limits
NOx	Dry Low NOx Good Combustion Practices	15 ppmvd at 15% O_2
CO	Clean Fuel Good Combustion Practices	15 ppmvd at 15% O_2
PM, PM-10, and PM-2.5	Clean Fuel Good Combustion Practices	0.0070 lb/MMBtu[1]
SO_2	Clean Fuel	Burn gas with total sulfur

	Good Combustion Practices	content of ≤ 96 ppmv, dropping to ≤ 16 ppmv once the three treatment trains are operational
VOC	Clean Fuel Good Combustion Practices	0.0022 lb/MMBtu[1]
GHG	Clean Fuel Good Combustion Practices	117.1 lb/MMBtu[1]

[1.] Emission limits are based on heat input in MMBtu/hr.

14.1 For EUs 25 through 30, the Permittee shall:

a. Install, operate, and maintain dry low NOx burners emissions controls on EUs 25 through 30, according to the manufacturer’s specifications, at all times the units are operating, except for short periods of startup, shutdown, and malfunction.

b. During periods of startup, shutdown, and malfunction operate EUs 25 through 30 according to manufacturer’s specifications and good combustion practices.

c. Perform regular maintenance according to the manufacturer’s or the operator’s maintenance procedures.

d. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format.

e. Keep a copy of either the manufacturer’s or the operator’s maintenance procedures.

14.2 To show compliance with the NOx emission limit set out in Table 4, the Permittee shall:

a. Submit to the Department vendor verification that the simple cycle turbines will comply with the NOx limit in Table 4 at least 60 days before startup of any of EUs 25 through 30.

b. Conduct an initial source test in accordance with Section 8 on at least two of EUs 25 through 30,[8] within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of the turbine, to demonstrate initial compliance with the NOx limit listed in Table 4 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU. One load must be within plus or minus 25 percent of 100 percent of peak load. The Permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A.

(iii) Each source test shall consists of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 4.

(iv) During each test run, measure the inlet air temperature.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 40.

14.3 To show compliance with the CO emission limit set out in Table 4, the Permittee shall:

a. Submit to the Department vendor verification that the simple cycle turbines will comply with the CO limit established in Table 4 at least 60 days before startup of any of EUs 25 through 30.

b. Conduct an initial source test, in accordance with Section 8 on at least two of EUs 25 through 30 within 180 days from the first of EUs 25 through 30 beginning operation to demonstrate initial compliance with the CO limit listed in Table 4 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A.

(iii) Each source test shall consists of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu as well as the appropriate units for the corresponding pollutant listed in Table 4.

(iv) During each test run, measure the inlet air temperature.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 40.

14.4 To show compliance with the VOC, PM, PM-10, and PM-2.5 emission limits set out in Table 4, the Permittee shall:

a. Submit to the Department, a certified manufacturer's guarantee demonstrating that EUs 25 through 30 will comply with the emission limits in Table 4 at least 60 days before startup of any of EUs 25 through 30; or

b. Conduct an initial source test, in accordance with Section 8 on at least two of EUs 25 through 30 within 180 days from the first of EUs 25 through 30 beginning operation to demonstrate initial compliance with the VOC, PM, PM-10, and PM-2.5 limits listed in Table 4 as follows:

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu heat input.

(iv) During each test run, measure the inlet air temperature.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 40.

14.5 To show compliance with the SO_2 emission limit set out in Table 4, the Permittee shall:

a. Monitor, record, and report in accordance with Condition 11.2.

b. Maintain good combustion practices at all times the units are in operation.

c. Upon completion of the third natural gas treatment train, limit the total sulfur content of the fuel gas fired in EUs 25 through 30 to no more than 16 ppmv. Once triggered; monitor, record, and report as follows:

(i) Notify the Department of the completed third natural gas treatment train in the first operating report required by Condition 25 that would be due after the third natural gas treatment train becomes operational.

(ii) Analyze a representative sample of the fuel burned by EUs 25 through 30 at least monthly to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

(iii) A current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel does not exceed the limit in Condition 14.5c.

(iv) Keep records of the sulfur content analysis required under Condition 14.5c(ii), or records specifying the maximum total sulfur content of the fuel required under Condition 14.5c(iii).

(v) Include copies of the records required by Condition 14.5c(iv) with the operating report required by Condition 25 for the period covered by the report.

(vi) Report as excess emissions in accordance with Condition 24, whenever the sulfur content of the fuel gas fired in EUs 25 through 30 exceeds 16 ppmv.

14.6 To show compliance with the GHG emission limit set out in Table 4, the Permittee shall:

a. Maintain good combustion practices at all times the units are in operation;

b. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

c. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

d. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

14.7 Report as described in Condition 24 if any of:

a. the emission rates determined by the source tests required by Conditions 14.2 through 14.4 exceed the limits in Table 4; or

b. Conditions 14.1 through 14.6 are not met.

15. **Black Start and Emergency Diesel-Fired Engines BACT Emission Limits:** Limit the emissions from the black start and emergency diesel-fired engines EUs 39 through 44 as specified in Table 5:

Table 5: Diesel-Fired Engines (EUs 39 through 44) – BACT Limits

<table>
<tr><th>Pollutant</th><th>EU</th><th>BACT Control</th><th colspan="2">BACT Emission Limits</th></tr>
<tr><td rowspan="2">NOx</td><td>39</td><td rowspan="2">Good Combustion Practices</td><td>3.3 g/hp-hr</td><td rowspan="11">500 hours each in any 12 consecutive month period</td></tr>
<tr><td>40 – 44</td><td>3.6 g/hp-hr</td></tr>
<tr><td rowspan="2">CO</td><td>39</td><td>Oxidation Catalyst</td><td>3.3 g/hp-hr</td></tr>
<tr><td>40 – 44</td><td>Good Combustion Practices</td><td>3.3 g/hp-hr</td></tr>
<tr><td rowspan="2">PM, PM-10, and PM-2.5</td><td>39</td><td rowspan="2">Good Combustion Practices & ULSD</td><td>0.045 g/hp-hr</td></tr>
<tr><td>40 – 44</td><td>0.19 g/hp-hr</td></tr>
<tr><td>SO_2</td><td>39 – 44</td><td>Good Combustion Practices & ULSD</td><td>Diesel sulfur content of ≤ 15 ppmw (ULSD)</td></tr>
<tr><td rowspan="2">VOC</td><td>39</td><td>Oxidation Catalyst</td><td>0.18 g/hp-hr</td></tr>
<tr><td>40 – 44</td><td>Good Combustion Practices</td><td>0.19 g/hp-hr</td></tr>
<tr><td>GHG</td><td>39 – 44</td><td>Good Combustion Practices</td><td>163.6 lb/MMBtu</td></tr>
</table>

15.1 For EU 39 the Permittee shall:

a. Install, operate, and maintain an oxidation catalyst according to the manufacturer's specifications, at all times the unit is operating, except for short periods of startup, shutdown, and malfunction.

b. During periods of startup, shutdown, and malfunction operate the EU according to manufacturer's specifications and good combustion practices.

15.2 To show compliance with the emission limits for EUs 39 through 44 in Table 5, the Permittee shall:

a. Limit the operation of each of EUs 39 through 44 to no more than 500 hours in any 12 consecutive month period. Monitor, record, and report as follows:

(i) Install, operate, and maintain an hour meter on each EU;

(ii) Record the hour meter reading for each EU on the last day of each month;

(iii) By the 15th day of each month, calculate and record:

(A) the number of hours that each EU operated during the previous month, if the meter is not operational assume continuous operation for that period; and

(B) the total number of hours each EU operated during the previous 12 consecutive months;

(iv) Report in each operating report required by Condition 25 the following information for each month of the reporting period:

(A) the hour meter reading obtained under Condition 15.2a(ii) for each EU; and

(B) the values determined under Condition 15.2a(iii) for each EU; and

b. Verify initial compliance with the CO, NOx + VOC, PM, PM-10, and PM-2.5 emission limits for EUs 39 through 44, established in Table 5 by either:

(i) Obtaining a certified manufacturer's guarantee that each diesel engine will comply with the CO, NOx + VOC, PM, PM-10, and PM-2.5 emission limits established in Table 5. Submit the emissions data to the Department in the first operating report required by Condition 25 after each of EUs 39 through 44 become fully operational; or

(ii) Conducting an initial source test in accordance with Section 8, for CO, NOx + VOC, PM, PM-10, and PM-2.5 within 180 days of each of EUs 39 through 44 beginning operation.

c. Verify compliance with the SO_2 emission limit listed in Table 5 by complying with Condition 11.1;

d. Perform regular maintenance following the manufacturer's or the operator's maintenance procedures;

e. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

f. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

15.3 Report as described in Condition 24 if:

a. any of EUs 39 through 44 exceed 500 hours per 12 consecutive month period;

b. any of the emission rates determined by the source tests required by Conditions 15.2b(ii) exceed the limits in Table 5; or

c. Conditions 15.1 through 15.2 are not met.

16. **Large Utility Heaters BACT Emission Limits:** Limit the emissions from large utility heaters EUs 31 through 33 as specified in Table 6:

Table 6: Large Utility Heaters (EUs 31 through 33) – BACT Limits

Pollutant	BACT Control	BACT Emission Limits
NOx	Low NOx Burners Good Combustion Practices	0.036 lb/MMBtu[1]
CO	Oxidation Catalyst Good Combustion Practices	0.007 lb/MMBtu[1]
PM, PM-10, and PM-2.5	Clean Fuel Good Combustion Practices	0.0079 lb/MMBtu[1]
SO_2	Clean Fuel Good Combustion Practices	Burn gas with total sulfur content of ≤ 96 ppmv, dropping to ≤ 16 ppmv once the three treatment trains are operational
VOC	Clean Fuel Good Combustion Practices	0.0029 lb/MMBtu[1]
GHG	Clean Fuel Good Combustion Practices	117.1 lb/MMBtu[1]

[1.] Emission limits are based on heat input in MMBtu/hr.

16.1 For EUs 31 through 33, the Permittee shall:

a. Install, operate, and maintain low NOx burners and an oxidation catalyst on EUs 31 through 33, according to the manufacturer's specifications, at all times the units are operating, except for short periods of startup, shutdown, and malfunction;

b. During periods of startup, shutdown, and malfunction operate EUs 31 through 33 according to manufacturer's specifications and good combustion practices;

c. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

d. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

e. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

16.2 To show compliance with the NOx and CO emission limits set out in Table 6, the Permittee shall:

a. Conduct an initial source test in accordance with Section 8, on one of EUs 31 through 33 within 180 days from the first of EUs 31 through 33 beginning operation.

(i) Conduct the source test for at least three loads representative of the normal operating range of the EU.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu.

(iv) During each test run, measure the pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 40.

b. Monitor the oxidation catalyst operating parameters as follows:

(i) Install temperature sensing devices to monitor the inlet air temperature of each installed oxidation catalyst.

(A) Monitor the exhaust temperature at the inlet to each oxidation catalyst unit at least once per hour during all periods of operation. Record for each calendar day the minimum and maximum inlet gas temperature of each oxidation catalyst unit. Data capture and recording may be electronic.

(B) Report the minimum and maximum daily inlet gas temperature of each oxidation catalyst unit for each calendar month in the operating report required by Condition 25.

(ii) Install gauges before and after the oxidation catalyst controls to monitor the pressure drop across each installed oxidation catalyst unit.

(A) Maintain the oxidation catalyst such that the pressure drop across each oxidation unit is within the acceptable range identified in the manufacturer’s specifications, or within the range determined by the most recent source tests under Conditions 16.2a(iv) and 16.3b(iv).

(B) If the pressure drop exceeds the acceptable differential identified in the manufacturer’s specifications, the oxidation catalyst unit shall be inspected, cleaned, or replaced, as necessary.

16.3 To show compliance with the PM, PM-10, PM-2.5, and VOC emission limits set out in Table 6, the Permittee shall:

a. Submit to the Department, a certified manufacturer's guarantee demonstrating that EUs 31 through 33 will comply with the PM, PM-10, PM-2.5, and VOC emission limits in Table 6 at least 60 days before startup of any of EUs 31 through 33; or

b. Within 180 days from initial startup of the first of EUs 31 through 33, conduct a source test in accordance with Section 8 of this permit to demonstrate initial compliance with the PM, PM-10, PM-2.5, and VOC limits listed in Table 6 as follows:

(i) Conduct the test on one of EUs 31 through 33 for at least three loads representative of the normal operating range of the EUs.

(ii) Use the applicable test method set out in 40 C.F.R. 60, Appendix A. Source test downstream of the catalytic oxidation control system.

(iii) Each source test shall consist of at least three 20-minute or longer valid test runs at each load. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lb/MMBtu.

(iv) During each test run, measure the pressure drop across the oxidation catalyst.

(v) The Permittee shall report the results of the source test to the Department in accordance with Condition 40.

16.4 To show compliance with the SO_2 emission limit set out in Table 6, the Permittee shall:

a. Monitor, record, and report in accordance with Condition 11.2.

b. Maintain good combustion practices at all times the units are in operation.

c. Upon completion of the third natural gas treatment train, limit the total sulfur content of the fuel gas fired in EUs 31 through 33 to no more than 16 ppmv. Once triggered; monitor, record, and report as follows:

(i) Notify the Department of the completed third natural gas treatment train in the first operating report required by Condition 25 that would be due after the third natural gas treatment train becomes operational.

(ii) Analyze a representative sample of the fuel burned by EUs 31 through 33 at least monthly to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

(iii) A current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel does not exceed the limit in Condition 16.4c.

(iv) Keep records of the sulfur content analysis required under Condition 16.4c(ii), or records specifying the maximum total sulfur content of the fuel required under Condition 16.4c(iii).

(v) Include copies of the records required by Condition 16.4c(iv) with the operating report required by Condition 25 for the period covered by the report.

(vi) Report as excess emissions in accordance with Condition 24, whenever the sulfur content of the fuel gas fired in EUs 31 through 33 exceeds 16 ppmv.

16.5 To show compliance with the GHG emission limit set out in Table 6, the Permittee shall:

a. Perform regular maintenance according to the manufacturer’s or the operator’s maintenance procedures;

b. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

c. Keep a copy of either the manufacturer’s or the operator’s maintenance procedures.

16.6 Report as described in Condition 24 if:

a. any of the emission rates determined by the source tests required by Conditions 16.2a or 16.3b exceed the limits in Table 6;

b. the inlet gas temperature of an oxidation catalyst unit is outside the acceptable range identified in the manufacturer’s specifications;

c. the pressure drop across an oxidation catalyst unit is outside the acceptable range identified in the manufacturer’s specifications, or outside the range determined by the most recent source tests under Conditions 16.2a(iv) and 16.3b(iv); or

d. any of Conditions 16.1 through 16.5 are not met.

17. **Small Utility Heaters BACT Emission Limits:** Limit the emissions from small utility heaters EUs 34 and 35 as specified in Table 7 and from EUs 36 through 38 as specified in Table 8:

Table 7: Buyback Gas Bath Heaters (EUs 34 and 35) – BACT Limits

Pollutant	EU	BACT Control	BACT Emission Limits	
NOx	34 & 35	Low NOx Burners Good Combustion Practices	0.036 lb/MMBtu[1]	500 hours each in any 12 consecutive month period
CO	34 & 35	Clean Fuel Good Combustion Practices	0.087 lb/MMBtu[1]	
PM, PM-10, and PM-2.5	34 & 35	Clean Fuel Good Combustion Practices	0.0079 lb/MMBtu[1]	
SO_2	34 & 35	Clean Fuel Good Combustion Practices	Burn gas with total sulfur content of ≤ 96 ppmv, dropping to ≤ 16 ppmv once the three treatment trains are operational	
VOC	34 & 35	Clean Fuel Good Combustion Practices	0.0057 lb/MMBtu[1]	
GHG	34 & 35	Clean Fuel Good Combustion Practices	117.1 lb/MMBtu[1]	

[1.] Emission limits are based on heat input in MMBtu/hr.

17.1 To show compliance with the emission limits for EUs 34 and 35 in Table 7, the Permittee shall:

a. Limit the operation of EUs 34 and 35 to no more than 500 hours each, in any 12-consecutive month period.

Monitor, record, and report as follows:

(i) Record the startup and shutdown times for each EU;

(ii) By the 15th day of each month, calculate and record:

(A) the number of hours that each EU operated during the previous month; and

(B) the total number of hours each EU operated during the previous 12 consecutive months.

(iii) Report in each operating report required by Condition 25 the following information for each month of the reporting period:

(A) The number of hours each EU operated during the month; and

(B) the number of hours each EU operated during the previous 12 consecutive months.

b. Install, operate, and maintain low NOx burners according to the manufacturer's specifications, at all times the units are operating.

c. Verify initial compliance with the NOx, CO, VOC, PM, PM-10, and PM-2.5 emission limits established in Table 7 as follows:

(i) Obtain a certified manufacturer's guarantee that each heater will comply with the emission limits established in Table 7. Submit the emissions data to the Department in the first operating report required by Condition 25 after each of EUs 34 and 35 commence operation; or

(ii) Conduct a source test in accordance with Section 8 for NOx, CO, VOC, PM, PM-10, and PM-2.5 within 180 days of startup of each of EUs 34 and 35.

d. To show compliance with the SO_2 emission limit listed in Table 7, the Permittee shall:

(i) Monitor, record, and report in accordance with Condition 11.2.

(ii) Upon completion of the third natural gas treatment train, limit the total sulfur content of the fuel gas fired in EUs 34 and 35 to no more than 16 ppmv. Once triggered; monitor, record, and report as follows:

(A) Notify the Department of the completed third natural gas treatment train in the first operating report required by Condition 25 that would be due after the third natural gas treatment train becomes operational.

(B) Analyze a representative sample of the fuel burned by EUs 34 and 35 at least monthly to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

(C) A current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel does not exceed the limit in Condition 17.1d(ii).

(D) Keep records of the sulfur content analysis required under Condition 17.1d(ii)(B), or records specifying the maximum total sulfur content of the fuel required under Condition 17.1d(ii)(C).

(E) Include copies of the records required by Condition 17.1d(ii)(D) with the operating report required by Condition 25 for the period covered by the report.

(F) Report as excess emissions in accordance with Condition 24, whenever the sulfur content of the fuel gas fired in EUs 34 and 35 exceeds 16 ppmv.

e. Perform regular maintenance according to the manufacturer's or the operator's maintenance procedures;

f. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

g. Keep a copy of either the manufacturer's or the operator's maintenance procedures.

Table 8: EUs 36 through 38 – BACT Limits

Pollutant	EU	BACT Control	BACT Emission Limits
NOx	36 – 38	Low NOx Burners Good Combustion Practices	0.036 lb/MMBtu[1]
CO	36 – 38	Clean Fuel Good Combustion Practices	0.087 lb/MMBtu[1]
PM, PM-10, and PM-2.5	36 – 38	Clean Fuel Good Combustion Practices	0.0079 lb/MMBtu[1]
SO_2	36 – 38	Clean Fuel Good Combustion Practices	Burn gas with total sulfur content of ≤ 96 ppmv, dropping to ≤ 16 ppmv once the three treatment trains are operational
VOC	36 – 38	Clean Fuel Good Combustion Practices	0.0057 lb/MMBtu[1]
GHG	36 – 38	Clean Fuel Good Combustion Practices	117.1 lb/MMBtu[1]

[1.] Emission limits are based on heat input in MMBtu/hr.

17.2 To show compliance with the emission limits for EUs 36 through 38 in Table 8, the Permittee shall:

a. Install, operate, and maintain low NOx burners according to the manufacturer's specifications, at all times the units are operating.

b. Verify initial compliance with the NOx, CO, VOC, PM, PM-10, and PM-2.5 emission limits established in Table 8 as follows:

(i) Obtain a certified manufacturer's guarantee that each heater will comply with the emission limits established in Table 8. Submit the emissions data to the Department in the first operating report required by Condition 25 after each of EUs 36 through 38 commence operation; or

(ii) Conduct a source test in accordance with Section 8 for NOx, CO, VOC, PM, PM-10, and PM-2.5 within 180 days of startup of each of EUs 36 through 38.

c. To show compliance with the SO_2 emission limit listed in Table 8, the Permittee shall:

(i) Monitor, record, and report in accordance with Condition 11.2.

(ii) Upon completion of the third natural gas treatment train, limit the total sulfur content of the fuel gas fired in EUs 36 through 38 to no more than 16 ppmv. Once triggered; monitor, record, and report as follows:

(A) Notify the Department of the completed third natural gas treatment train in the first operating report required by Condition 25 that would be due after the third natural gas treatment train becomes operational.

(B) Analyze a representative sample of the fuel burned by EUs 36 through 38 at least monthly to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

(C) A current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel does not exceed the limit in Condition 17.2c(ii).

(D) Keep records of the sulfur content analysis required under Condition 17.2c(ii)(B), or records specifying the maximum total sulfur content of the fuel required under Condition 17.2c(ii)(C).

(E) Include copies of the records required by Condition 17.2c(ii)(D) with the operating report required by Condition 25 for the period covered by the report.

(F) Report as excess emissions in accordance with Condition 24, whenever the sulfur content of the fuel gas fired in EUs 36 through 38 exceeds 16 ppmv.

d. Perform regular maintenance according to the manufacturer’s or the operator’s maintenance procedures;

e. Keep records of any maintenance that would have a significant effect on emissions. The records may be kept in electronic format; and

f. Keep a copy of either the manufacturer’s or the operator’s maintenance procedures.

17.3 Report as described in Condition 24 whenever the limit in Condition 17.1a is exceeded, if any of the emission rates determined by the source tests conducted under Conditions 17.1c(ii) or 17.2b(ii) exceed the limits in Table 7 or Table 8, or whenever Conditions 0 through 0 are not met.

18. **Vent Gas Disposal (Flares) BACT Emission Limits:** Limit the emissions from flares EUs 45 through 52 as specified in Table 9:

Table 9: EUs 45 through 52 – BACT Limits

Pollutant	BACT Control	BACT Emission Limits	
NOx	Proper flare work practice requirements and establishing a flaring minimization plan	0.068 lb/MMBtu	500 hours per 12-month rolling period per unit of flaring during startup, shutdown, and maintenance events[9]
CO		0.37 lb/MMBtu	
PM, PM-10, and PM-2.5		40 µg/L (0.028 lb/MMBtu)	
SO_2		Burn gas with total sulfur content of ≤ 96 ppmv, dropping to ≤ 16 ppmv once the three treatment trains are operational	
VOC		0.57 lb/MMBtu	
GHG		117.1 lb/MMBtu	

18.1 To show compliance with the work practice and flaring minimization BACT limits for EUs 45 through 52 indicated in Table 9, the Permittee shall comply with the following flare minimization practices to reduce emissions during startups, shutdowns, and other maintenance events:

a. Flare Minimization Plan: Prior to operation of the flare EUs, the Permittee shall develop and keep on-site a flare minimization plan; and

b. The Permittee shall train all operators responsible for the day-to-day operation of the flares on the flare minimization practices and the specific procedures to follow during process startup, shutdown, and other flaring events.

c. Flares shall be designed and operated during startups, shutdowns, and other maintenance events, in accordance with the general control device and work practice requirements specified in 40 C.F.R. 60.18(c) through (f).

18.2 Limit the number of hours EUs 45 through 52 flare to no more than 500 hours each during startup, shutdown, and maintenance events, in any 12 consecutive months.[9]

Monitor, record, and report as follows:

a. Calculate and record monthly, the number of hours EUs 45 through 52 flared during startups, shutdowns, and other maintenance events for the previous month;

b. Calculate and record monthly, the number of hours EUs 45 through 52 flared during startups, shutdowns, and other maintenance events for the previous 12 consecutive months;

[9] This 500 hour flaring limit does not include pilot and purge, emergency, or process upset flaring.

c. Report in the operating report required in Condition 25, for each month covered in the report, the total hours that each of EUs 45 through 52 flared for the previous 12 consecutive months; and

d. Report as described in Condition 24 whenever the flaring hours calculated under Condition 18.2b exceed the limit in Condition 18.2.

18.3 To show compliance with the SO_2 emission limit set out in Table 9, the Permittee shall:

a. Monitor, record, and report in accordance with Condition 11.2.

b. Upon completion of the third natural gas treatment train, limit the total sulfur content of the fuel gas fired in EUs 45 through 52 to no more than 16 ppmv. Once triggered; monitor, record, and report as follows:

(i) Notify the Department of the completed third natural gas treatment train in the first operating report required by Condition 25 that would be due after the third natural gas treatment train becomes operational.

(ii) Analyze a representative sample of the fuel burned by EUs 45 through 52 at least monthly to determine the sulfur content using either ASTM D4084, D5504, D4810, D4913, D6228 or GPA Standard 2377, or a listed method approved in 18 AAC 50.035(b)-(c) or 40 C.F.R. 60.17 incorporated by reference in 18 AAC 50.040(a)(1); or

(iii) A current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel does not exceed the limit in Condition 18.3b.

(iv) Keep records of the sulfur content analysis required under Condition 18.3b(ii), or records specifying the maximum total sulfur content of the fuel required under Condition 18.3b(iii).

(v) Include copies of the records required by Condition 18.3b(iv) with the operating report required by Condition 25 for the period covered by the report.

(vi) Report as excess emissions in accordance with Condition 24, whenever the sulfur content of the fuel gas fired in EUs 45 through 52 exceeds 16 ppmv.

19. **Fuel Tanks BACT Emission Limits:** Limit the emissions from fuel tanks EUs 53 through 61 as specified in Table 10:

Table 10: EUs 53 through 61 – BACT Limits

Pollutant	BACT Control	BACT Emission Limit
VOC	Submerged Fill	0.59 tpy

19.1 To show compliance with the VOC emission limit for diesel fuel tanks EUs 53 through 60 set out in Table 10, the Permittee shall install, operate, and maintain tanks with submerged fill design.

19.2 To show compliance with the VOC emission limit for gasoline fuel tank EU 61 set out in Table 10, the Permittee shall install, operate, and maintain a white painted exterior tank with a submerged fill pipe no more than 6 inches from the bottom of the tank.

19.3 Compliance with the VOC limit in Table 10 shall be demonstrated by supplying the Department with as built schematics and photograph of EU 61, demonstrating compliance with Condition 19.2 in the first operating report required under Condition 25 after installation of the tank.

Section 6 Recordkeeping, Reporting, and Certification Requirements

20. **Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "*Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.*" Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

    20.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if

    a. A certifying authority registered under AS 09.25.510 verifies that the electronic signature is authentic; and

    b. The person providing the electronic signature has made an agreement with the certifying authority described in Condition 20.1a that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.

21. **Submittals.** The Permittee shall submit reports, compliance certifications, and/or other submittals required by this permit, via the Department's website (AOS System at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option).

    21.1 Upon approval by the Department, the Permittee can submit reports by alternative methods, certified in accordance with Condition 20, and submitted by email under a cover letter using dec.aq.airreports@alaska.gov; or by letter, or form if the Permittee does not have the technical ability to submit the records using the Department's website.

22. **Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke, reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the federal administrator.

23. **Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five-years after the date of collection, including:

    23.1 copies of all reports and certifications submitted pursuant to this section of the permit; and

    23.2 records of all monitoring required by this permit, and information about the monitoring including (if applicable):

    a. calibration and maintenance records, original strip chart or computer-based recordings for continuous monitoring instrumentation;

b. sampling dates and times of sampling or measurements;

c. the operating conditions that existed at the time of sampling or measurement;

d. the date analyses were performed;

e. the location where samples were taken;

f. the company or entity that performed the sampling and analyses;

g. the analytical techniques or methods used in the analyses; and

h. the results of the analyses.

24. **Excess Emissions and Permit Deviation Reports.**

24.1 Except as provided in Condition 26 the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report

(i) emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable;

b. in accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that caused emissions in excess of a technology based emissions standard;

c. report all other excess emissions and permit deviations

(i) within 30 days after the end of the month during which the emissions or deviation occurred, except as provided in Condition 24.1c(iii); or

(ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under Condition 24.1c(i); and

(iii) for failure to monitor, as required in other applicable conditions of this permit.

24.2 When reporting either excess emissions or permit deviations, the Permittee shall report using either the Department's on-line form, which can be found at http://dec.alaska.gov/applications/air/airtoolsweb, or if the Permittee prefers, the form contained in Attachment 2 of this permit. The Permittee must provide all information called for by the form that is used.

24.3 If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up an excess emissions report.

25. **Operating Reports.** Submit to the Department an operating report by August 1 for the period January 1 through June 30 of the current year and by February 1 for the period July 1 through December 31 of the previous year. The report shall be submitted under a cover letter certified in accordance with Condition 20.

25.1 The operating report must include all information required to be in operating reports by other conditions of this permit, for the period covered by the report.

25.2 When excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 25.1, the Permittee shall identify

a. the date of the deviation;

b. the equipment involved;

c. the permit condition affected;

d. a description of the excess emissions or permit deviation; and

e. any corrective action or preventative measures taken and the date of such actions; or

25.3 When excess emissions or permit deviations have already been reported under Condition 24 the Permittee shall cite the date or dates of those reports.

26. **Air Pollution Prohibited.** No person may permit any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property.

26.1 If emissions present a potential threat to health or safety, the Permittee shall report any such emissions according to Condition 24.

26.2 As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 26.

26.3 The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

a. after investigation because of complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 26; or

b. the Department notifies the Permittee that it has found a violation of Condition 26.

26.4 The Permittee shall keep records of

a. the date and time, and nature of all emissions complaints received;

b. the name of the person or persons that complained, if known;

c. a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 26; and

d. any corrective actions taken or planned for complaints attributable to emissions from the stationary source.

26.5 Report in each operating report required by Condition 25 a brief summary report for complaints which must include:

a. the number of complaints received;

b. the number of times the Permittee or the Department found corrective action necessary;

c. the number of times action was taken on a complaint within 24 hours; and

d. the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

26.6 The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

27. **Emission Inventory Reporting.** The Permittee shall submit to the Department reports of actual emissions,[10] by emissions unit, of CO, NH_3, NOx, PM_{10}, $PM_{2.5}$, SO_2, VOCs and Lead (Pb) (and lead compounds) using the form in Attachment 3 of this permit, as follows:

27.1 Each year by April 30, if the stationary source's potential to emit for the previous calendar year equals or exceeds:

a. 250 TPY of NH_3, PM_{10}, $PM_{2.5}$, or VOCs; or

b. 2,500 TPY of CO, NOx, or SO_2.

27.2 Every third year by April 30, if the stationary source's potential to emit for the previous calendar year (except actual emissions for Pb) equals or exceeds:

a. 0.5 TPY of actual Pb, or

b. 1,000 TPY of CO; or

c. 100 TPY of SO_2, NH_3, PM_{10}, $PM_{2.5}$, NOx, or VOCs.

[10] If the stationary source has not commenced construction or operation by the end of the calendar year, submit a transmittal letter to the Department's Anchorage office certified in accordance with Condition 20, which identifies the source's emissions inventory for the previous fiscal year to be zero tons per year and provide estimates for when construction and operation will commence.

27.3 For reporting under Condition 27.2, the Permittee shall report in 2021 for calendar year 2020, 2024 for calendar year 2023, etc., in accordance with the Environmental Protection Agency schedule.

27.4 Include in the report required by this condition, the required data elements contained within the form in Attachment 3 or those contained in Tables 2a and 2b of Appendix A to Subpart A of 40 C.F.R. 51 and Emission Inventory Instructions available in Air Online Services (AOS) system for each emissions unit.

a. Submit the report through electronic online submission via the Department’s AOS system at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option.

b. If the AOS system is not available, the report may be submitted by

(i) email using dec.aq.airreports@alaska.gov; or

(ii) hard copy to the following address: ADEC Air Permits Program, ATTN: Emissions Inventory, 555 Cordova Street, Anchorage, Alaska 99501.

Section 7 Standard Permit Conditions

28. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

    28.1 an enforcement action; or

    28.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

29. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

30. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

31. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

32. The permit does not convey any property rights of any sort, nor any exclusive privilege.

33. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

    33.1 enter upon the premises where an emissions unit subject to this permit is located or where records required by the permit are kept;

    33.2 have access to and copy any records required by this permit;

    33.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

    33.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

Section 8 General Source Test Requirements

34. **Requested Source Tests.** In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

35. **Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

 35.1 at a point or points that characterize the actual discharge into the ambient air; and

 35.2 at the maximum rated burning or operating capacity of the emissions unit or another rate determined by the Department to characterize the actual discharge into the ambient air.

36. **Reference Test Methods.** The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

 36.1 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(a) in accordance with the methods and procedures specified in 40 CFR 60.

 36.2 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(b) in accordance with the methods and procedures specified in 40 CFR 61.

 36.3 Conduct source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) in accordance with the methods and procedures specified in 40 CFR 63.

 36.4 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

 36.5 Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

 36.6 Source testing for emissions of PM-10 and PM-2.5 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

 36.7 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

37. **Test Deadline Extension.** The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department's appropriate division director or designee.

38. **Test Plans.** Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days of receiving a request under Condition 34 and at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

39. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

40. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit one certified copy of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results as set out in Condition 20. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

Section 9 Permit Documentation

Date	Document Details
December 28, 2017	Department receives original application
March 6, 2018	Department sends incompleteness letter to Permittee
May 1, 2018	Department receives additional application information
June 29, 2018	Department sends 2nd incompleteness letter to Permittee
September 24, 2018	Department receives additional application information
October 2, 2018	Department receives additional application information
December 18, 2018	Department sends information request to Permittee
January 25, 2019	Department receives information request response from Permittee
December 3, 2019	Deparment sends information request to Permittee Ex Parte
January 10, 2020	Department receives information request response from Permittee
April 28, 2020	Deparment sends information request to Permittee Ex Parte
May 5, 2020	Department receives information request response from Permittee
June 9, 2020	Deparment sends information request to Permittee Ex Parte
June 11, 2020	Department receives information request response from Permittee

Section 10 Complaint Form

COMPLAINT FORM

Date Time:

Activities Involved:

Provide a description of reported complaint. Attach sheets as necessary.

If applicable, operational conditions which contributed to the complaint:

If applicable, ambient conditions which contributed to the complaint:

If applicable, describe measures taken to immediately address the complaint.

If applicable, describe measures taken to address preventing the condition which generated the complaint.

If applicable, describe any reason that you feel the complaint may not be a violation:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate and complete.

________________ ________________________ ________________

Printed Name Signature Date

Attachment 1 - Visible Emissions Form

VISIBLE EMISSION OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources." Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form: for a more detailed discussion of each part of the form, refer to "Instructions for Use of Visible Emission Observation Form."

- Source Name: full company name, parent company or division or subsidiary information, if necessary.
- Address: street (not mailing or home office) address of facility where VE observation is being made.
- Phone (Key Contact): number for appropriate contact.
- Source ID Number: number from NEDS, agency file, etc.
- Process Equipment, Operating Mode: brief description of process equipment (include type of facility) and operating rate, % capacity, and/or mode (e.g. charging, tapping, shutdown).
- Control Equipment, Operating Mode: specify type of control device(s) and % utilization, control efficiency.
- Describe Emission Point: for identification purposes, stack or emission point appearance, location, and geometry; and whether emissions are confined (have a specifically designed outlet) or unconfined (fugitive).
- Height Above Ground Level: stack or emission point height relative to ground level; can use engineering drawings, Abney level, or clineometer.
- Height Relative to Observer: indicate height of emission point relative to the observation point.
- Distance from Observer: distance to emission point; can use rangefinder or map.
- Direction from Observer: direction plume is traveling from observer.
- Describe Emissions and Color: include physical characteristics, plume behavior (e.g., looping, lacy, condensing, fumigating, secondary particle formation, distance plume visible, etc.), and color of emissions (gray, brown, white, red, black, etc.). Note color changes in comments section.
- Visible Water Vapor Present?: check "yes" if visible water vapor is present.
- If Present, is Plume…: check "attached" if water droplet plume forms prior to exiting stack, and "detached" if water droplet plume forms after exiting stack.
- Point in Plume at Which Opacity was Determined: describe physical location in plume where readings were made (e.g., 1 ft above stack exit or 10 ft. after dissipation of water plume).
- Describe Plume Background: object plume is read against, include texture and atmospheric conditions (e.g., hazy).
- Background Color: sky blue, gray-white, new leaf green, etc.
- Sky Conditions: indicate cloud cover by percentage or by description (clear, scattered, broken, overcast).
- Wind Speed: record wind speed; can use Beaufort wind scale or hand-held anemometer to estimate.
- Wind Direction From: direction from which wind is blowing; can use compass to estimate to eight points.
- Ambient Temperature: in degrees Fahrenheit or Celsius.
- Wet Bulb Temperature: can be measured using a sling psychrometer
- RH Percent: relative humidity measured using a sling psychrometer; use local US Weather Bureau measurements only if nearby.
- Source Layout Sketch: include wind direction, sun position, associated stacks, roads, and other landmarks to fully identify location of emission point and observer position.
- Draw North Arrow: to determine, point line of sight in direction of emission point, place compass beside circle, and draw in arrow parallel to compass needle.
- Sun's Location: point line of sight in direction of emission point, move pen upright along sun location line, mark location of sun when pen's shadow crosses the observer's position.
- Observation Date: date observations conducted.
- Start Time, End Time: beginning and end times of observation period (e.g., 1635 or 4:35 p.m.).
- Data Set: percent opacity to nearest 5%; enter from left to right starting in left column. Use a second (third, etc.) form, if readings continue beyond 30 minutes. Use dash (-) for readings not made; explain in adjacent comments section.
- Comments: note changing observation conditions, plume characteristics, and/or reasons for missed readings.
- Range of Opacity: note highest and lowest opacity number.
- Observer's Name: print in full.
- Observer's Signature, Date: sign and date after performing VE observation.
- Organization: observer's employer.
- Certified By, Date: name of "smoke school" certifying observer and date of most recent certification.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY DIVISION - VISIBLE EMISSIONS OBSERVATION FORM

Page No.__________

Source Name | Type of Source

Observation Date | Start Time | End Time

Address

City | State | Zip

Phone # (Key Contact) | Source ID Number

Process Equipment | Operating Mode

Control Equipment | Operating Mode

Describe Emission Point

Height above ground level | Height relative to observer | Inclinometer Reading

Distance From Observer | Direction From Observer Start End

Describe Emissions & Color
Start | End

Visible Water Vapor Present? If yes, determine approximate distance from the
No Yes stack exit to where the plume was read

Point in Plume at Which Opacity Was Determined

Describe Plume Background | Background Color
Start | Start
End | End

Sky Conditions: Start

Wind Speed | Wind Direction From Start End

Ambient Temperature | Wet Bulb Temp | RH percent

NOTES: 1 Stack or Point Being Read 2 Wind Direction From
3 Observer Location 4 Sun Location 5 North Arrow 6 Other Stacks

Min \ Sec	0	15	30	45	Comments
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Range of Opacity
Minimum | Maximum

I have received a copy of these opacity observations

Print Name:

Signature:

Title | Date

Print Observer's Name

Observer's Signature | Date

Organization

Certified By: | Date

Attachment 2 - ADEC Notification Form

Excess Emissions and Permit Deviation Reporting
State of Alaska Department of Environmental Conservation
Division of Air Quality

Gas Treatment Plant	AQ1524CPT01
Stationary Source Name	**Air Quality Permit**
Alaska Gasline Development Corporation	
Company Name	**Date**

When did you discover the Excess Emissions/Permit Deviation?

Date: ______ / ______ / _________ Time: ______ :/ ______

When did the event/deviation?

Begin Date: _____ / _____ / ________ Time: ______ : _______ (Use 24-hr clock.)

End Date _____ / _____ / ________ Time: ______ : _______ (Use 24-hr clock.)

What was the duration of the event/deviation? ____ : ____ (hrs:min) or ________ days

(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for notification: (please check only 1 box and go to the corresponding section)

☐ Excess Emissions Complete Section 1 and Certify

☐ Deviation from permit conditions complete Section 2 and certify

☐ Deviation from COBC, CO, or Settlement Agreement Complete Section 2 and certify

Section 1. Excess Emissions

(a) **Was the exceedance** ☐ Intermittent or ☐ Continuous

(b) **Cause of Event (Check one that applies):**

☐ Start Up/Shut Down ☐ Natural Cause (weather/earthquake/flood)

☐ Control Equipment Failure ☐ Scheduled Maintenance/Equipment Adjustments

☐ Bad fuel/coal/gas ☐ Upset Condition ☐ Other

(c) **Description**

Describe briefly, what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance.

(d) **Emission unit(s) Involved:**

Identify the emission units involved in the event, using the same identification number and name as in the permit. Identify each emission standard potentially exceeded during the event and the exceedance.

EU ID	EU Name	Permit Condition Exceeded/Limit/Potential Exceedance

(e) **Type of Incident** (please check only one):

☐Opacity % ☐Venting (gas/scf) ☐Control Equipment Down
☐Fugitive Emissions ☐Emission Limit Exceeded ☐Record Keeping Failure
☐Marine Vessel Opacity ☐Failure to monitor/report ☐Flaring
☐Other:

(f) **Unavoidable Emissions:**

Do you intend to assert that these excess emissions were unavoidable? ☐YES ☐NO
Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐YES ☐NO

Certify Report (go to end of form)

Section 2. Permit Deviations

(a) **Permit Deviation Type** (check only one box corresponding with the section in the permit)

☐ Emission Unit Specific
☐ General Source Test/Monitoring Requirements
☐ Recordkeeping/Reporting/Compliance Certification
☐ Standard Conditions Not Included in Permit
☐ Generally Applicable Requirements
☐ Reporting/Monitoring for Diesel Engines
☐ Insignificant Emission Unit
☐ Stationary Source-Wide
☐ Other Section: (title of section and section # of your permit)

(b) **Emission unit(s) Involved:**

Identify the emission unit involved in the event, using the same identification number and name as in the permit. List the corresponding Permit condition and the deviation.

EU ID	Emission Unit Name	Permit Condition /Potential Deviation

(c) **Description of Potential Deviation:**

Describe briefly, what happened and the cause. Include the parameters/operating conditions and the potential deviation.

(d) **Corrective Actions:**

Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence.

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name: ______________________ Title: ______________________ Date: _________

Signature: ______________________ Phone Number: ______________________

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To submit this report:

1. Department's Air Online Services using the Permittee Portal option:
   http://dec.alaska.gov/applications/air/airtoolsweb
   If submitted online, report must be submitted by an authorized E-Signer for the stationary source.

Or

2. Fax to: 907-451-2187

Or

3. Email to: DEC.AQ.Airreports@alaska.gov

Or

4. Mail to: ADEC
   Air Permits Program
   610 University Avenue
   Fairbanks, AK 99709-3643

Or

5. Phone Notifications: 907-451-5173
   Phone notifications require a written follow-up report.

Attachment 3 - Emission Inventory Form

ADEC Reporting Form **Emission Inventory Reporting** **State of Alaska Department of Environmental Conservation** **Division of Air Quality**		**Emission Inventory Year- [ ]**
Mandatory information is highlighted in bright yellow. Make additional copies as needed.		
Stationary Source Detail		
Inventory start date		
Inventory end date		
ADEC ID or Permit Number		
EPA ID:		
Census Area/ Community		
Facility Name		
Facility Physical Location	**Address:**	
	City, State, Zip Code:	
	Latitude:	**Longitude:**
	Legal Description:	
Owner Name & Address & contact number	**Owner Name:**	
	Owner Address:	
	Phone Number:	
Mailing Contact Information	**Mailing Address:**	
Line of Business (NAICS)		
Line of Business (SIC)		
Facility Status:		

Emissions Unit Data			
Specifications			
ID		**Design Capacity**	
Description			
Emissions Unit Status			
Manufacturer		**Manufactured Year**	
Model Number		**Serial Number**	
Regulations			
Regulation/Description:			
Control Equipment (List All if applicable):			
ID			
System Description	-		
Equipment Type(s)			
Manufacturer			
Model			
Control Efficiency (%)			
Capture Efficiency (%)			
Pollutants Controlled		**Reduction Efficiency (%):**	
		Reduction Efficiency (%):	

Processes	
Process	**Primary Process**
SCC Code	(ex. 20100201)
	>
	>
	>
	>
Material Processed	
Period Start	
Period End	
Throughput (units)	
Summer %	
Fall %	
Winter %	
Spring %	
Operational Schedule	
Days/Week	
Hours/Day	
Weeks/Year	
Hours/Year	

Fuel Characteristics			
Heat Content	**Elem. Sulfur Content (%)**	**H2S Sulfur Content**	**Ash Content (if applicable)**
Heating			

Heat Input	**Heat Output**	**Heat Values Convention**

Emissions Operating Type:					
Pollutant	**Emission Factor (EF)**	**EF Numerator**	**EF Denominator**	**EF Origin**	**Tons**
Carbon Monoxide (CO)					
Nitrogen Oxides NOx					
PM_{10} Primary (PM_{10}-PRI)					
$PM_{2.5}$ Primary (PM_{25}-PRI)					
Sulfur Dioxide (SO_2)					
Ammonia (NH_3)					
Lead and lead compounds					
Volatile Organic Compounds (VOC)					
Emissions' Release Point					
Release Point ID					
Apportion%					

Process	**Secondary Process**
SCC Code	(ex. 20100201)
	>
	>
	>
	>
Material Processed	
Period Start	
Period End	
Throughput (units)	
Summer %	
Fall %	
Winter %	
Spring %	
Operational Schedule	
Days/Week	
Hours/Day	
Weeks/Year	
Hours/Year	

Fuel Characteristics			
Heat Content	**Elem. Sulfur Content (%)**	**H2S Sulfur Content**	**Ash Content (if applicable)**

Heating		
Heat Input	**Heat Output**	**Heat Values Convention**

Emissions Operating Type:					
Pollutant	**Emission Factor (EF)**	**EF Numerator**	**EF Denominator**	**EF Origin**	**Tons**
Carbon Monoxide (CO)					
Nitrogen Oxides NOx					
PM_{10} Primary (PM_{10}-PRI)					
$PM_{2.5}$ Primary (PM_{25}-PRI)					
Sulfur Dioxide (SO_2)					
Ammonia (NH_3)					
Lead and lead compounds					
Volatile Organic Compounds (VOC)					
Emissions' Release Point					
Release Point ID					
Apportion%					

Stack Detail (Release Point)	
> Specifications	
ID	
Type	
Description	
Stack Status	
> Stack Parameters	
Stack Height (ft)	
Stack Diameter (ft)	
Exit Gas Temp (F)	
Exit Gas Velocity (fps)	
Exit Gas Flow Rate	
> Geographic Coordinate	
Latitude	
Longitude	

Datum	
Accuracy (meters)	
Base Elevation (meters)	

Certification:

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name:_______________________________Title______________________Date ______

Signature:__________________________________ Phone number________________________

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To submit this report:

1. Department's Air Online Services using the Permittee Portal option:

   http://dec.alaska.gov/applications/air/airtoolsweb

   Or

2. Fax to: 907-269-7508

   Or

3. Email to: DEC.AQ.Airreports@alaska.gov

   Or

4. Mail to: ADEC Division of Air Quality
   ATTN: Emissions Inventory
   555 Cordova Street
   Anchorage, AK 99501

Technical Analysis Report
For the terms and conditions of
Construction Permit AQ1524CPT01

Issued to Alaska Gasline Development Corporation

For the Gas Treatment Plant

Alaska Department of Environmental Conservation
Air Permits Program

Prepared by Dave Jones
Reviewed by Aaron Simpson

Final – August 13, 2020

1. INTRODUCTION

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Construction Permit AQ1524CPT01 to the Alaska Gasline Development Corporation (AGDC) for the Gas Treatment Plant (GTP). The project triggers Prevention of Significant Deterioration (PSD) review under 18 AAC 50.306 for oxides of nitrogen (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter not exceeding 10 microns (PM-10), particulate matter with an aerodynamic diameter not exceeding 2.5 microns (PM-2.5), volatile organic compounds (VOC), and greenhouse gases (GHG). The project is also classified under 18 AAC 50.316 as a major source of Hazardous Air Pollutants (HAPs) for formaldehyde and ethylbenzene.

1.1 Description of Source

GTP is a new stationary source located on Alaska's North Slope in the Prudhoe Bay Unit (PBU), approximately 8.5 miles north-northwest of Deadhorse. The facility is classified under Standard Industrial Classification code 4922 for natural gas transmission and under North American Industrial Classification code 486210 for pipeline transportation of natural gas.

1.2 Application Description

AGDC submitted an initial application for this project on December 28, 2017. They retransmitted the application on February 14, 2018 due to missing/corrupted electronic files in the original submittal. They submitted several addenda through January 25, 2019. AGDC is requesting authorization to install and operate simple cycle and cogeneration gas-fired turbines, reciprocating internal combustion engines, heaters, flares, and fuel tanks to support the treatment of gas.

1.3 Project Description

GTP is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaska's North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the PBU and the Point Thomson Unit (PTU) and treat/process the gas, before it is sent 807 miles through a 42-inch diameter pipeline to a liquefaction facility in Nikiski on Alaska's Kenai Peninsula for export in foreign commerce.

The emissions units (EUs) at the stationary source will include cogeneration gas-fired turbines with supplemental firing duct burners for gas compression, simple cycle gas-fired turbines for power generation, gas-fired heaters for building and process heat, as well as flares for control of excess gas. In addition, the GTP will include a diesel-fired black start generator, several diesel-fired firewater pumps and emergency generators, and storage tanks for diesel and gasoline fuels.

Process Systems

The design of GTP would have an average stream day inlet natural gas treating capacity of 3.7 billion standard cubic feet per day (BSCF/D) and a 3.9 BSCF/D peak capacity,[11] and would be able to accommodate varying compositions of natural gas received from the PBU and PTU.

The design for GTP consists of three parallel treatment trains, each sized to process roughly 1.3 BSCF/D of sour feed gas. The process removes the majority of carbon dioxide (CO_2) and hydrogen sulfide (H_2S) from the sour feed gas to the specification of the Liquefaction Facility, and most of the water (to a dew point specification for the Mainline). The treated gas then would be compressed in stages and routed to a natural gas chilling unit. The chilling unit uses a refrigerant to cool the gas. After refrigeration, the natural gas would be delivered to the Mainline at pressures up to 2,075 psig.

GTP would include facilities in each treatment train to collect the CO_2 and H_2S removed from the natural gas. The CO_2/H_2S stream also would contain water and some hydrocarbons. The CO_2/H_2S stream from each train would be compressed and treated to remove water. The gaseous stream containing predominantly CO_2 and H_2S from each train would be combined into a single stream (GTP Byproduct) that would be sent to the PBU for reinjection into the reservoir for enhanced oil recovery.

As discussed in the following sections, the water removed from both the natural gas and the Byproduct streams would be injected at the GTP site through Class 1 industrial wells located on the GTP Pad.

Inlet Facilities

The gas from the PBU would be metered for custody transfer at the PBU before entering the Prudhoe Bay Gas Transmissions Line (PBTL). Similarly, the feed gas from PTU would be custody transfer metered at the PTU before entering the Point Thomson Gas Transmissions Line (PTTL).

The PTU gas would be sent through an inlet knock-out drum to allow any liquids that may form in the PTTL to drop out of the natural gas stream before entering the processing trains. The natural gas from PBU would be combined with the natural gas flow from PTU and then sent to the process trains. The inlet facilities would be located on the northeast corner of the GTP Pad.

Acid Gas Removal Unit

There would be one acid gas removal unit (AGRU) per train. The AGRU would remove CO_2 and H_2S from the sour feed gas with the use of an amine solution and packed absorber tower commonly found in the natural gas treatment industry. The natural gas leaving the absorber tower would meet LNG specifications for CO_2 and H_2S but would also need to be treated by a gas dehydration unit to remove water to meet pipeline specification.

A regenerator, or second packed tower, would be used to release the CO_2 and H_2S from the amine solution. Once the CO_2 and H_2S are removed from the amine solution, the amine solution would be recirculated back to the absorber and the gaseous CO_2/H_2S stream would be compressed and dehydrated prior to return to PBU.

[11] Average stream day rate denotes the weighted 12-month average of monthly stream day rate values. Stream day rate represents the physical capacity of the facility at a particular ambient condition and does not account for planned or unplanned downtime (assume 100-percent uptime).

Treated Gas Dehydration Unit

There would be one treated gas dehydration unit system per train. The system would use glycol in a packed absorber tower to extract water from the natural gas stream. The dry natural gas stream would then flow to a treated gas compression system.

A regenerator, or second packed tower, would be used to release the water from the glycol solution using a stripping gas stream. Once the water has been removed, the glycol would be recirculated.

Treated Gas Compression

There would be one treated gas compression system per train. The purpose of the treated gas compression system would be to compress the dry natural gas to adequate pressure so that it enters the Mainline at the expected operating pressure. This would be done using natural gas turbine-driven compressors. GTP total treated gas compression power requirements would be approximately 298,000 ISO horsepower (combined for six units). The flue gas from the treated gas compression turbine drivers and from the CO_2 compression gas turbine drivers would be used to heat the process heat medium, as discussed below.

The treated natural gas would flow from the treated gas compression system in each train to common treated natural gas chillers prior to introduction into the Mainline. During winter periods when the air temperature is sufficiently cold, adequate cooling can be provided by the compressor discharge coolers, and the treated natural gas chilling and refrigeration system would not need to operate.

Treated Gas Chilling and Refrigeration

Treated natural gas from the three trains would be combined and then cooled to 30 °F upon entering the Mainline, using a propane refrigerant for chilling. The treated natural gas would flow from the chillers through a metering station and into the Mainline.

The refrigeration system would have two compressors (totaling approximately 27,000 brake horsepower) to provide flexibility between the summer months, when both compressors are expected to operate, and winter months when either one or none of the compressors would be operating. For initial fill and makeup, liquid propane would be transferred to the GTP from the PBU. The treated natural gas chillers and refrigeration system would be located on the northeast corner of the GTP pad.

CO_2 Compression and Dehydration

Each train would include one CO_2 compression and one dehydration system. The CO_2 compression system would compress the gaseous stream of predominately CO_2 (with some H_2S) released from the amine solution in four stages of compression. The first two stages would make up the low-pressure portion of the system and the last two stages would make up the high-pressure portion of the system. The low-pressure system would compress the gas to approximately 530 psig at which point the gas would be dehydrated by glycol in a contact tower. The process for dehydration would be similar to the treated gas dehydration unit described previously. Following dehydration, the CO_2 would flow to the high-pressure portion of the system where the gas would be boosted to approximately 4,000 psig for return to PBU. Following compression, the gas from each train would be combined into a single stream and then flow through a meter to the PBU. CO_2 compression at the GTP would be driven by natural gas turbines totaling approximately 205,000 ISO horsepower (combined for six units).

Building Heat Medium System

One building heat medium system would be located in the common utility area. The purpose of the building heat medium system would be to provide heat for freeze protection for process buildings, storage tanks, liquid drums, and air coolers as required to prevent equipment damage (during both normal and off-case operations) and to facilitate equipment maintenance. It would use a mixture of water and glycol in a closed loop system as the heat medium, which is heated by gas-fired heaters. This system would not heat the Operations Center buildings.

Cooling Medium Systems

Cooling medium systems would supply coolant to major GTP machinery (e.g., large compressors, etc.), pumps that require seal cooling, and some process heat exchangers. The cooling medium would be cooled using an air cooler. There would be one cooling medium system in each of the three trains. Additionally, air compressors, refrigeration compressors, and power generators would have their own cooling systems.

Process Heat Medium Systems

The purpose of the process heat medium systems would be to provide process heating to the AGRU reboilers. The system would use pressurized water as the heat medium, which is heated in the waste heat recovery units (WHRUs) by the exhaust from the gas turbines on the treated gas compressors and the CO_2 compressors in each train. Additional process heating requirements would be supplied by gas-fired duct burners (supplemental firing) within each of the WHRUs.

Electrical Power Generation System

The essential power generation for the GTP and GTP camp during construction would be supplied by a diesel generator located on the GTP Pad. An emergency diesel generator, located at the GTP Operations Center, would provide backup power for stairwell pressurization fans at the GTP Operations Center. Another emergency diesel generator would be provided at the Communications building to provide backup power.

The main power generation for the operation of the facility would be through six power generator natural gas turbines. The turbines would be located on the GTP Pad totaling approximately 267,000 to 299,000 horsepower. Emissions would be controlled using dry low emissions combustors.

Fuel Gas System

The fuel gas system supplies gas to the Operations Center via transfer line from the PBU Central Gas Facility. The fuel gas system would supply fuel gas to the gas turbines, supplemental firing for WHRUs, fired heaters, and flare system purges. Fuel gas would also be used as blanketing gas for a variety of equipment that either requires a higher pressure or a lower oxygen content than the nitrogen blanketing gas.

Flare System

Four flare systems would be provided for the GTP: high pressure (HP) hydrocarbon flare, low pressure (LP) hydrocarbon flare, HP CO_2 flare, and LP CO_2 flare. The flares are located to minimize radiant heat impacts on the facilities and to minimize downwind personnel exposure resulting from the prevailing wind direction.

Separate HP and LP hydrocarbon flares enable more efficient design by allowing low pressure gas to enter its own flare system with no interference from high pressure gas sources. HP and LP CO_2 systems would be segregated to keep water out of the high-pressure CO_2 system.

The design of the GTP facilities would not generate any continuous process or utility flow sources to flare or vent, except from limited pilot/purge streams. The flare system is for startup, emergency, pre-commissioning, commissioning, shutdown, or upset conditions. In general, protection systems would be designed to minimize potential flaring/venting flow rates to reduce impacts.

Diesel and Gasoline Fuel System

Arctic grade ultra-low sulfur diesel (ULSD) would be trucked to the GTP plant and stored for use on the GTP pad and Operations Center pad. The diesel fuel storage tank on the GTP pad would have a nominal capacity of 19,500 gallons and be sized to hold two weeks of diesel for the emergency and essential generators, diesel firewater pumps, and diesel fuel for service vehicles. The majority of this volume would be for vehicle usage. Usage by the emergency and essential diesel generators and firewater system would be for emergency and testing purposes.

The diesel-driven firewater pumps, communication tower, and the camp emergency generators would be located at the operations camp. Day tanks would be supplied directly via truck delivery to the operations camp.

Gasoline would be trucked to the GTP plant and stored for use at the GTP Operations Center. The gasoline storage tank would have a nominal capacity of approximately 10,000 gallons and would supply gasoline for service vehicles.

Chemical Storage

Storage for process chemicals would be provided on the GTP Pad. The chemical storage tanks would include storage for amine (130,000 gallons), triethylene glycol (26,500 gallons), and diesel (discussed previously). There would also be an additional empty tank with a capacity of 962,000 gallons to hold the amine from one train if it were to be taken out of service. A hydrocarbon holding tank would also be provided at the GTP Operations Center. The hydrocarbon holding tank is designed to hold recyclable waste diesel, glycol, solvents, miscellaneous fuels, and lubricants. This tank would be emptied using a vacuum truck as needed and either recycled or transported to an existing approved handling facility. Sizing for the hydrocarbon holding tank would be confirmed during later stages of the Project design.

2. CLASSIFICATION FINDINGS

Based on review of the application, the Department finds that:

1. This project is classified under 18 AAC 50.306(a) for beginning actual construction of a new stationary source that is PSD major for NOx, CO, VOC, PM, PM-10, PM-2.5, SO_2, and GHG.
2. This project is also classified under 18 AAC 50.316 as a major source of HAPs for formaldehyde and ethylbenzene.

3. APPLICATION REVIEW FINDINGS

Based on review of the application, the Department finds that:

1. GTP is classified as a major stationary source under 40 C.F.R. 52.21(b)(1)(i)(b) because the stationary source has the potential to emit 250 tpy or more of a regulated air pollutant.
2. GTP has potential NOx, CO, PM, PM-10, PM-2.5, SO_2, and VOC emissions that are PSD significant, per 40 C.F.R. 52.21(b)(23)(i). The GHG are subject to regulation per 40 C.F.R. 52.21(b)(49)(iv)(a). Therefore, the project requires a PSD permit under 18 AAC 50.306(a) for these pollutants.
3. AGDC did not model the secondary emissions occurring during the construction phase of the project. Instead, the Department is imposing a requirement to construct and maintain vertical, uncapped exhaust stacks on all temporary camp engines (Condition 9.1), a fugitive dust control plan (Condition 10.1), and a requirement to install and operate PM-10 and PM-2.5 ambient air monitoring stations (Condition 10.2) throughout the construction phase. For more information see the Modeling Report in Appendix D.
4. The treatment trains at the GTP will separate out a byproduct consisting of mostly CO_2 and H_2S gases (GTP Byproduct). This GTP Byproduct will be returned to the Prudhoe Bay Unit where it will be re-injected for use in enhanced oil recovery.
5. AGDC included a BACT analysis for all of the applicable emission unit types at the stationary source.
6. For compliance with the BACT emission limits the Department required initial source testing for larger units with add-on controls. BACT limits for EUs 1 through 6, 7 through 12, and 25 through 30, require source testing on two like kind units, and EUs 31 through 33 require source testing on one unit as representation for all of the units. Smaller units that are not likely to exceed the BACT limits are required to either submit to the Department a manufacturer's guarantee that the units will meet the BACT limits or source test the units to show they meet the numerical BACT emissions limits.
7. The cogeneration turbines EUs 1 through 12 and their associated waste heat recovery units (WHRU) EUs 13 through 24 were treated as one EU type for the BACT process, which is found in Appendix B, Section 3.0 of this TAR. The emission rates listed for these EUs in the permit and TAR account for both the turbine and their associated WHRU operating concurrently and shall be measured after the WHRU. The WHRU have supplemental firing burners that use only exhaust air from the turbine for combustion and no supplemental air. The oxidation catalyst selected as BACT for controlling CO emissions for these EUs shall be installed after the WHRU so as to capture exhaust from both the turbine and the WHRU.
8. The PTE for all gas-fired EUs (turbines, heaters, and flares) use a total sulfur content not to exceed 96 ppmv. This is a conservative assumption of the sulfur emissions considering that the BACT limits require AGDC to burn gas with a total sulfur content not to exceed 16 ppmv once the three gas treatment trains are operational.

4. EMISSIONS SUMMARY AND PERMIT APPLICABLITY

Table 11 shows the emissions summary and permit applicability with assessable emissions from the stationary source, listed in tons per year (tpy). Emission factors and detailed calculations are provided in Appendix A.

A summary of the potential to emit (PTE) and assessable PTE, as determined by the Department, is shown in Table 11 below.

Table 11: Emissions Summary and Permit Applicability

Parameter	Emissions (tpy)					
	NOx	CO	VOC	PM-2.5	PM-10	SO_2
PTE Authorized Under AQ1524CPT01	3,321.7	9,026.9	13,087.2	903.4	903.4	1,076.3
Title V Permit Thresholds	100	100	100	100	100	100
Title V Permit Required?	Yes	Yes	Yes	Yes	Yes	Yes
Assessable Emissions	3,322	9,027	13,087	903	903	1,076
	27,415					

Table Notes:
27,415 tons is a conservative estimate that includes flaring at maximum capacity for 500 hours per year. Without the inclusion of maximum flaring the total assessable emissions is 3,465 tons.
PM-10 emissions include PM-2.5 emissions. Therefore, PM-2.5 is not counted in total assessable emissions.
Fuel Gas Sulfur Content: 96 ppmv used for calculating SO_2 emissions from all gas-fired EUs.
Diesel Fuel Sulfur Content: 15 ppmw used for calculating SO_2 emissions from all diesel-fired EUs

Table 12: Major Source and PSD Review Applicability

Parameter	NOx	CO	VOC	PM-2.5	PM-10	PM	SO_2	CO_2e[1]
PTE for AQ1524CPT01 excluding fugitive emissions	3,321.7	9,026.9	13,087.2	903.4	903.4	903.4	1,076.3	7,278,238
PSD Major Source Threshold	250	250	250	250	250	250	250	N/A
Major Source Triggered?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No
PSD Significant Emissions Rates	40	100	40[3]	10[2]	15	25	40	75,000
PSD Review Triggered?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Table Notes:
[1] GHG are subject to regulation because the stationary source is major for a non-GHG pollutant and the carbon dioxide equivalent (CO_2e) is at least 75,000 tpy.
[2] PSD review for PM-2.5 can also be triggered by NOx and SO_2 precursor emissions, as specified under 40 C.F.R. 52.21(b)(23)(i).
[3] VOC acts as a surrogate for ozone (O_3). In addition to the VOC emissions trigger, PSD review for O_3 can also be triggered by NOx emissions, as specified under 40 C.F.R. 52.21(b)(23)(i).

5. PERMIT CONDITIONS

The bases for the standard and general conditions imposed in Construction Permit AQ1524CPT01 are described below.

Section 1: Emissions Unit Inventory

The EUs authorized and/or restricted by this permit are listed in Table 1 of the permit. Unless otherwise noted in the permit, the information in Table 1 is for identification purposes only. Condition 1 is a general requirement to comply with AS 46.14 and 18 AAC 50 when installing a replacement EU.

Section 2: Fee Requirements

Condition 3, Administration Fees

18 AAC 50.306(d)(2) requires the Department to include a requirement to pay fees in accordance with 18 AAC 50.400 – 18 AAC 50.420 in each PSD permit issued under 18 AAC 50.306.

Conditions 4 and 5, Assessable Emissions

18 AAC 50.346(b)(1) requires the Department to include the Standard Permit Condition (SPC) I language for construction permits. However, for Construction Permit AQ1524CPT01 the Department modified the SPC I language to include a website address for submitting emission estimates through the Air Online Services (AOS) System. The Department also updated its mailing/delivery addresses.

As indicated by Footnote 3, if the stationary source has not commenced construction or operation on or before March 31, the Permittee is required to submit a transmittal letter certified by the responsible official under 18 AAC 50.205 indicating that the assessable emissions for the source are zero for the previous fiscal year.

Section 3: State Emission Standards

Condition 6, Visible Emissions

Visible emissions, excluding condensed water vapor, from an industrial process or fuel-burning equipment may not reduce visibility through the effluent by more than 20 percent averaged over six consecutive minutes, under 18 AAC 50.055(a)(1). Per 18 AAC 50.990(39), “fuel-burning equipment” does not include mobile internal combustion engines (e.g., NREs).

The Department is requiring an initial compliance demonstration within 60 days of startup of the new diesel-fired EUs 39 through 44. For the fuel gas-fired EUs 1 through 38, the Department is requiring a statement in each operating report that the EUs fired only fuel gas as fuel. For the flaring EUs 45 through 52 the Department is requiring an initial Method 9 observation during the first daylight flare event.

Condition 7, Particulate Matter (PM)

Particulate Matter emitted from an industrial process or fuel burning equipment may not exceed 0.05 grains per cubic foot of exhaust gas (gr/dscf), averaged over three hours, under 18 AAC 50.055(b).

Experience has shown there is a correlation between opacity and particulate matter. Twenty percent visible emissions would normally provide for compliance with the 0.05 gr/dscf emission limit. As such, compliance with opacity limits is included as a surrogate method of assuring compliance with the PM standards.

Condition 8, Sulfur Compound Emissions

Sulfur compound emissions from an industrial process or fuel burning equipment may not exceed 500 ppm averaged over a period of three hours, under 18 AAC 50.055(c).

Calculations show that fuel oil with sulfur content less than 0.74 percent by weight will comply with the state emissions standard. Calculations show that fuel gas with sulfur content less than 4,000 parts per million by volume will comply with the state standards. The Permittee demonstrates compliance with Condition 8 by complying with the ambient air quality protection requirement Conditions 11.1 and 11.2, which require combusting only ULSD (0.0015 percent sulfur by weight) and firing only fuel gas with a sulfur content of no more than 96 ppmv.

Section 4: Ambient Air Quality Protection Requirements

Conditions 9 – 12

18 AAC 50.010 contains the ambient air quality standards, and the Department will include conditions to protect these standards when warranted. The Department determined that conditions are warranted to protect the 1-hour and annual NO_2; 24-hour PM-10; 24-hour and annual PM-2.5; 1-hour and 8-hour CO; and 1-hour, 3-hour, 24-hour, and annual SO_2 AAAQS for the reasons described in Appendix D of this TAR.

Section 5: Best Available Control Technology (BACT)

Conditions 13 – 19

The project triggers PSD review under 18 AAC 50.306 for NOx,SO_2, CO, PM, PM-10, PM-2.5, VOCs, and GHGs. The Department performed a BACT analysis of all the available control options for equipment emitting the triggered pollutants listed above. The BACT evaluation process selects the best pollutant control option based on feasibility, economics, energy, and other impacts. The full BACT analysis is contained in Appendix B of this TAR and a summary of the BACT analysis is contained in Appendix C of this TAR.

Section 6: General Recordkeeping, Reporting, and Certification Requirements

Condition 20, Certification

18 AAC 50.205 requires the Permittee to certify any permit application, report, affirmation, or compliance certification submitted to the Department. This requirement is reiterated as a standard permit condition in 18 AAC 50.345(j). Construction Permit AQ1524CPT01 uses the standard condition language, but also expands it by allowing the Permittee to provide electronic signatures.

Condition 21, Submittals

Condition 21 clarifies where the Permittee should send their reports, certifications, and other submittals required by the permit. The Department included this condition from a practical perspective rather than a regulatory obligation.

Condition 22, Information Requests

AS 46.14.020(b) allows the Department to obtain a wide variety of emissions, design and operational information from the owner and operator of a stationary source. This statutory provision is reiterated as a standard permit condition in 18 AAC 50.345(i). The Department used the standard language in Construction Permit AQ1524CPT01.

Condition 23, Recordkeeping Requirements

The condition restates the regulatory requirements for recordkeeping, and supplements the recordkeeping defined for specific conditions in the permit. The records being kept provide an evidence of compliance with this requirement.

Condition 24, Excess Emission and Permit Deviation Reports

This condition reiterates the notification requirements in 18 AAC 50.235(a)(2) and 18 AAC 50.240 regarding unavoidable emergencies, malfunctions, and excess emissions. Also, the Permittee is required to notify the Department when emissions or operations deviate from the requirements of the permit. The Department used the Standard Condition III language, but with updated web-links.

Condition 25, Operating Reports

The Department mostly used the Standard Operating Permit Condition VII language for the operating report condition. However, the Department modified or eliminated the Title V only aspects in order to make the language applicable for a construction permit.

Condition 26, Air Pollution Prohibited

18 AAC 50.110 prohibits any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property. Condition 26 reiterates this prohibition as a permit condition. The Department used the Standard Permit Condition II language for Construction Permit AQ1524CPT01.

Condition 27, Emission Inventory Reporting

18 AAC 50.346(b)(8) requires the Department to include the SPC XV emission inventory language for construction permits. 18 AAC 50.346(b)(9) requires the Department to include the SPC XVI Emission Inventory Form (Attachment 3) for construction permits. The Department used the language in SPC XV for the permit condition, but corrected the emissions threshold amount for Pb in Condition 27.2a, from 5 TPY to 0.5 TPY actual emissions. The Department has also added Conditions 27.4a, 27.4b, and updated the submittal requirements in the Emission Inventory Form to clarify the requirements for report submittal using the Department’s Air Online Services (AOS) system, or using email, or mailing out a hard copy if the AOS system is not available.

Section 7: Standard Permit Conditions

Conditions 28 – 33

As required under 18 AAC 50.345, the Department may include the standard permit conditions set out in subsections (c)(1) and (2), and (d) through (o), as applicable for a minor or construction permit. As required under 18 AAC 50.346, the Department will include the standard permit conditions set out in this subsection in each construction permit or Title V permit, unless the Department determines that emissions unit-specific or stationary source-specific conditions more adequately meet the requirements of this chapter, or that no comparable condition is appropriate for the stationary source or emissions unit.

The Department included all of the minor/construction permit-related standard conditions of 18 AAC 50.345 in Construction Permit AQ1524CPT01. The Department incorporated these standard conditions as follows:

- 18 AAC 50.345(c)(1) and (2) is incorporated as Condition 28 of Section 7 (Standard Permit Conditions);
- 18 AAC 50.345(d) through (h) is incorporated as Conditions 29 through 33, respectively, of Section 7 (Standard Permit Conditions);
- As previously discussed, 18 AAC 50.345(i) is incorporated as Condition 22 and 18 AAC 50.345(j) is incorporated as Condition 20 of Section 6 (Recordkeeping, Reporting, and Certification Requirements); and
- 18 AAC 50.345(k) is incorporated as Condition 34, and 18 AAC 50.345(l) through (o) is incorporated as Conditions 37 through 40, respectively, of Section 8 (General Source Testing Requirements). See the following discussion.

Section 8: General Source Test Requirements

Conditions 34 – 40

AS 46.14.180 states that monitoring requirements must be, “based on test methods, analytical procedures, and statistical conventions approved by the federal administrator or the department or otherwise generally accepted as scientifically competent.” The Department incorporated this requirement as follows:

- Condition 35 requires the Permittee to conduct their source tests under conditions that reflects the actual discharge to ambient air; and
- Condition 36 requires the Permittee to use specific EPA reference methods when conducting a source test.

Section 8 also includes the previously discussed standard conditions for source testing.

6. PERMIT ADMINISTRATION

Construction Permit AQ1524CPT01 is the initial permit for the Gas Treatment Plant. Alaska Gasline Development Corporation may therefore operate in accordance with Construction Permit AQ1524CPT01 upon issuance.

Appendix A: Emissions Calculations

Table 13 presents details of the EUs, their characteristics, and emissions. Potential emissions are estimated using maximum annual operation for all fuel burning equipment as defined in 18 AAC 50.990(39) subject to any operating limits.

Table 13: Detailed Permanent EU Inventory and Potential to Emit (tpy)

EU ID	Emissions Unit Description	Rating		Annual Operating Hours	NOx CO EF Units	NO_x		CO		VOC PM-2.5 PM-10 EF Units	VOC		PM_{10}		$PM_{2.5}$		SO_2	CO_2e
						EF	tpy	EF	tpy		EF	tpy	EF	tpy	EF	tpy	tpy	1,000 tpy
1[1]	Train 1a Treated Gas Compressor Turbine (includes SF WHR)	575	MMBtu/hr	8760	ppmv	17	105.24	5	18.84	lb/MMBtu	0.0022	4.85	0.0063	15.92	0.0063	15.92	37.84	294.92
2[1]	Train 1b Treated Gas Compressor Turbine (includes SF WHR)	575	MMBtu/hr	8760	ppmv	17	105.24	5	18.84	lb/MMBtu	0.0022	4.85	0.0063	15.92	0.0063	15.92	37.84	294.92
3[1]	Train 2a Treated Gas Compressor Turbine (includes SF WHR)	575	MMBtu/hr	8760	ppmv	17	105.24	5	18.84	lb/MMBtu	0.0022	4.85	0.0063	15.92	0.0063	15.92	37.84	294.92
4[1]	Train 2b Treated Gas Compressor Turbine (includes SF WHR)	575	MMBtu/hr	8760	ppmv	17	105.24	5	18.84	lb/MMBtu	0.0022	4.85	0.0063	15.92	0.0063	15.92	37.84	294.92
5[1]	Train 3a Treated Gas Compressor Turbine (includes SF WHR)	575	MMBtu/hr	8760	ppmv	17	105.24	5	18.84	lb/MMBtu	0.0022	4.85	0.0063	15.92	0.0063	15.92	37.84	294.92
6[1]	Train3b Treated Gas Compressor Turbine (includes SF WHR)	575	MMBtu/hr	8760	ppmv	17	105.24	5	18.84	lb/MMBtu	0.0022	4.85	0.0063	15.92	0.0063	15.92	37.84	294.92
7[1]	Train 1a CO2 Compressor Turbine (includes SF WHR)	433	MMBtu/hr	8760	ppmv	17	80.46	5	14.41	lb/MMBtu	0.0022	3.64	0.0063	11.99	0.0063	11.99	28.50	221.96
8[1]	Train 1b CO2 Compressor Turbine (includes SF WHR)	433	MMBtu/hr	8760	ppmv	17	80.46	5	14.41	lb/MMBtu	0.0022	3.64	0.0063	11.99	0.0063	11.99	28.50	221.96
9[1]	Train 2a CO2 Compressor Turbine (includes SF WHR)	433	MMBtu/hr	8760	ppmv	17	80.46	5	14.41	lb/MMBtu	0.0022	3.64	0.0063	11.99	0.0063	11.99	28.50	221.96
10[1]	Train 2b CO2 Compressor Turbine (includes SF WHR)	433	MMBtu/hr	8760	ppmv	17	80.46	5	14.41	lb/MMBtu	0.0022	3.64	0.0063	11.99	0.0063	11.99	28.50	221.96
11[1]	Train 3a CO2 Compressor Turbine (includes SF WHR)	433	MMBtu/hr	8760	ppmv	17	80.46	5	14.41	lb/MMBtu	0.0022	3.64	0.0063	11.99	0.0063	11.99	28.50	221.96
12[1]	Train 3b CO2 Compressor Turbine (includes SF WHR)	433	MMBtu/hr	8760	ppmv	17	80.46	5	14.41	lb/MMBtu	0.0022	3.64	0.0063	11.99	0.0063	11.99	28.50	221.96
25[2]	Power Generation Turbines	40,465	kW	8760	ppmv	15	91.53	15	55.72	lb/MMBtu	0.0022	3.75	0.0070	11.78	0.0070	11.78	25.36	197.98
26[2]	Power Generation Turbines	40,465	kW	8760	ppmv	15	91.53	15	55.72	lb/MMBtu	0.0022	3.75	0.0070	11.78	0.0070	11.78	25.36	197.98
27[2]	Power Generation Turbines	40,465	kW	8760	ppmv	15	91.53	15	55.72	lb/MMBtu	0.0022	3.75	0.0070	11.78	0.0070	11.78	25.36	197.98
28[2]	Power Generation Turbines	40,465	kW	8760	ppmv	15	91.53	15	55.72	lb/MMBtu	0.0022	3.75	0.0070	11.78	0.0070	11.78	25.36	197.98
29[2]	Power Generation Turbines	40,465	kW	8760	ppmv	15	91.53	15	55.72	lb/MMBtu	0.0022	3.75	0.0070	11.78	0.0070	11.78	25.36	197.98
30[2]	Power Generation Turbines	40,465	kW	8760	ppmv	15	91.53	15	55.72	lb/MMBtu	0.0022	3.75	0.0070	11.78	0.0070	11.78	25.36	197.98

31[3]	Building Heat Medium Heater	275	MMBtu/hr	8760	lb/MMBtu	0.036	43.32	0.007	8.42	lb/MMBtu	0.0029	3.43	0.0079	9.47	0.0079	9.47	18.07	140.91
32[3]	Building Heat Medium Heater	275	MMBtu/hr	8760	lb/MMBtu	0.036	43.32	0.007	8.42	lb/MMBtu	0.0029	3.43	0.0079	9.47	0.0079	9.47	18.07	140.91
33[3]	Building Heat Medium Heater (spare)	275	MMBtu/hr	0														
34	Buyback Gas Bath Heater Primary Heater (Standby)	0.15	MMBtu/hr	8760	lb/MMBtu	0.036	0.024	0.087	0.059	lb/MMBtu	0.0057	0.004	0.0079	0.005	0.0079	0.005	0.011	0.079
	Buyback Gas Bath Heater Primary Heater (Maximum)	25	MMBtu/hr	500	lb/MMBtu	0.036	0.23	0.087	0.55	lb/MMBtu	0.0057	0.036	0.0079	0.050	0.0079	0.050	0.10	0.74
35[3]	Buyback Gas Bath Heater Secondary Heater (Standby)	0.15	MMBtu/hr	8760	lb/MMBtu	0.036	0.024	0.087	0.059	lb/MMBtu	0.0057	0.004	0.0079	0.005	0.0079	0.005	0.011	0.079
	Buyback Gas Bath Heater Secondary Heater (Maximum)	21	MMBtu/hr	500	lb/MMBtu	0.036	0.19	0.087	0.45	lb/MMBtu	0.0057	0.030	0.0079	0.041	0.0079	0.041	0.079	0.61
36[3]	Operations Camp Heater	32	MMBtu/hr	8760	lb/MMBtu	0.036	5.03	0.087	12.14	lb/MMBtu	0.0057	0.79	0.0079	1.10	0.0079	1.10	2.12	16.35
37[3]	Operations Camp Heater	32	MMBtu/hr	8760	lb/MMBtu	0.036	5.03	0.087	12.14	lb/MMBtu	0.0057	0.79	0.0079	1.10	0.0079	1.10	2.12	16.35
38[3]	Operations Camp Heater (spare)	32	MMBtu/hr	0														
39[4]	Black Start Diesel Generator Engine	4,060	hp	500	g/hp-hr	3.25	7.27	3.25	7.27	g/hp-hr	0.18	0.39	0.045	0.10	0.045	0.10	0.010	1.16
40[5]	Main Diesel Firewater Pump Engine	250	hp	500	g/hp-hr	3.56	0.49	3.25	0.45	g/hp-hr	0.19	0.03	0.19	0.026	0.19	0.026	0.0008	0.072
41[5]	Main Diesel Firewater Pump Engine	250	hp	500	g/hp-hr	3.56	0.49	3.25	0.45	g/hp-hr	0.19	0.03	0.19	0.026	0.19	0.026	0.0008	0.072
42[5]	Main Diesel Firewater Pump Engine	250	hp	500	g/hp-hr	3.56	0.49	3.25	0.45	g/hp-hr	0.19	0.03	0.19	0.026	0.19	0.026	0.0008	0.072
43[5]	Dormitory Emergency Diesel Generator Engine	335	hp	500	g/hp-hr	3.56	0.66	3.25	0.60	g/hp-hr	0.19	0.03	0.19	0.035	0.19	0.035	0.0011	0.096
44[5]	Communications Tower Emergency Generator Engine	201	hp	500	g/hp-hr	3.56	0.39	3.25	0.36	g/hp-hr	0.19	0.02	0.19	0.021	0.19	0.021	0.0006	0.058
45[6]	HP Hydrocarbon Flare East (Pilot/Purge)	7.85	MMBtu/hr	8760	lb/MMBtu	0.068	2.34	0.37	12.72	lb/MMBtu	0.57	19.59	0.028	0.97	0.028	0.97	0.52	4.03
	HP Hydrocarbon Flare East (Maximum)	73,307	MMBtu/hr	500	lb/MMBtu	0.068	1,246.23	0.37	6,780.93	lb/MMBtu	0.57	10,446.3	0.028	517.19	0.028	517.2	309.28	2,146.04
46[6]	HP Hydrocarbon Flare West (Pilot/Purge)	7.85	MMBtu/hr	8760	lb/MMBtu	0.068	2.34	0.37	12.72	lb/MMBtu	0.57	19.59	0.028	0.97	0.028	0.97	0.52	4.03
47[6]	LP Hydrocarbon Flare East (Pilot/Purge)	1.44	MMBtu/hr	8760	lb/MMBtu	0.068	0.43	0.37	2.33	lb/MMBtu	0.57	3.59	0.028	0.18	0.028	0.18	0.09	0.74
	LP Hydrocarbon Flare East (Maximum)	4,497	MMBtu/hr	500	lb/MMBtu	0.068	76.44	0.37	415.93	lb/MMBtu	0.57	640.76	0.028	31.72	0.028	31.72	16.90	131.64
48[6]	LP Hydrocarbon Flare West (Pilot/Purge)	1.44	MMBtu/hr	8760	lb/MMBtu	0.068	0.43	0.37	2.33	lb/MMBtu	0.57	3.59	0.028	0.18	0.028	0.18	0.09	0.74
49[6]	HP CO2 Flare East (Pilot/Purge)	2.96	MMBtu/hr	8760	lb/MMBtu	0.068	0.88	0.37	4.80	lb/MMBtu	0.57	7.40	0.028	0.37	0.028	0.37	0.20	1.52
	HP CO2 Flare East (Maximum)	3,155	MMBtu/hr	500	lb/MMBtu	0.068	53.63	0.37	291.79	lb/MMBtu	0.57	449.52	0.028	22.26	0.028	22.26	38.70	92.35
50[6]	HP CO2 Flare West (Pilot/Purge)	2.96	MMBtu/hr	8760	lb/MMBtu	0.068	0.88	0.37	4.80	lb/MMBtu	0.57	7.40	0.028	0.37	0.028	0.37	0.20	1.52
51[6]	LP CO2 Flare East (Pilot/Purge) (3 Flares)	6.83	MMBtu/hr	8760	lb/MMBtu	0.068	2.03	0.37	11.07	lb/MMBtu	0.57	17.05	0.028	0.84	0.028	0.84	0.45	3.50
	LP CO2 Flare East (Maximum)	9,630	MMBtu/hr	500	lb/MMBtu	0.068	163.71	0.37	890.78	lb/MMBtu	0.57	1,372.28	0.028	67.94	0.028	67.94	118.13	281.91

	(3 Flares)																
52[6]	LP CO2 Flare West (Pilot/Purge) (3 Flares)	6.83 MMBtu/hr	8760	lb/MMBtu	0.068	2.03	0.37	11.07	lb/MMBtu	0.57	17.05	0.028	0.84	0.028	0.84	0.45	3.50
53 – 61[7]	Diesel and Gasoline Storage Tanks	35,100 gal (total)	N/A	N/A							0.59						
Total Emissions (Without Maximum Flare)						**1,781.7**		**647.4**			**178.4**		**264.3**		**264.3**	**593.3**	**4,626.30**
Total Emissions (With Maximum Flare)						**3,321.7**		**9,026.9**			**13,087.2**		**903.4**		**903.4**	**1,076.3**	**7,278.23**

Table Notes:
Fuel Gas Heat Content (HHV): 1,077 Btu/scf
Fuel Gas Sulfur Content: 96 ppmv used for calculating SO_2 emissions from all gas-fired EUs.
Diesel Fuel Sulfur Content: 15 ppmw used for calculating SO_2 emissions from all diesel-fired EUs.
[1]NOx, CO, particulate matter, PM-10, PM-2.5, EFs provided by Permittee. PTE for NOx and CO assumes no additional air for supplemental firing duct burners outside of turbine exhaust. VOC EF is Permittee’s proposal for uncontrolled emissions with 70% reduction due to oxidation catalyst.
[2]NOx and CO EFs provided by Permittee. Particulate matter, PM-10, and PM-2.5 EFs are the total particulate EF for gas turbines from AP-42 Table 3.1-2a. VOC EF from AP-42 Table 3.1-2a.
[3]NOx, CO EF provided by Permittee. Particulate matter, PM-10, and PM-2.5 EFs are the total particulate EF for gas boilers from AP-42 Table 1.4-2. VOC EF from AP-42 Table 1.4-2. EUs 33 and 38 are spare units and do not have PTE. Condition 9.4 limits concurrent operations of these spare units with their counterparts.
[4]EFs are from EPA Tier 4 Final. NOx, and VOC (NMHC) use a 25% not to exceed factor of safety.CO uses a 25% not to exceed factor of safety and 80% control from oxidation catalyst. Particulate matter, PM-10, and PM-2.5 use a 50% not to exceed factor of safety.
[5]NOx, CO, VOC, particulate matter, PM-10, and PM-2.5 EFs are EPA Tier 3 with a 25% not to exceed factor of safety. NOx is assumed to be 95% of NMHC + NOx, and VOC is 5% of NMHC + NOx.
[6]NOx and CO EFs from AP-42 Table 13.5-1. Particulate matter, PM-10, and PM-2.5 EFs from AP-42 Table 13.5-1 for soot (lightly smoking flare). VOC EF from AP-42 Table 1.4-2 and converted to lb/MMBtu using fuel gas heat content of 1,077 Btu/scf.
[7]VOC PTE calculated using EPA’s Tanks software.

Appendix B: Best Available Control Technology

1.0 INTRODUCTION

The Alaska Gasline Development Corporation's (AGDC's) Gas Treatment Plant (GTP) triggered Prevention of Significant Deterioration (PSD) requirements for carbon monoxide (CO), oxides of nitrogen (NOx), sulfur dioxide (SO_2), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM-10), particulate matter with an aerodynamic diameter of 2.5 microns or less (PM-2.5), volatile organic compounds (VOC), and greenhouse gases (GHG). This appendix includes the Department of Environmental Conservation's (Department's) review of AGDC's Gas Treatment Plant's Best Available Control Technology (BACT) analysis for CO, NOx, SO_2, PM, PM-10, PM-2.5 (the Department will refer to PM, PM-10, and PM-2.5 collectively as particulates in this BACT analysis), VOC, and GHG for its technical accuracy and adherence to accepted engineering cost estimation practices.

2.0 BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 C.F.R. 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to: identify BACT for the permanent emission units (EUs) at the GTP that emit CO, NOx, SO_2, particulates, VOC, and GHG; establish emission limits which represent BACT; and assess the level of monitoring, recordkeeping, and reporting (MR&R) requirements necessary to ensure AGDC applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table 2-1 presents the EUs subject to BACT review.

Table 2-1: EUs Subject to BACT Review

EUs	Description of EU
1 – 6	Treated Gas Compressor Turbines (Cogeneration)
7 – 12	CO_2 Compressor Turbines (Cogeneration)
13 – 24	Waste Heat Recovery Units Supplemental Firing Burners
25 – 30	Power Generation Turbines (Simple Cycle)
31 – 38	Utility Heaters
39 – 44	Compression Ignition Engines
45 – 52	Vent Gas Disposal (Flares)
53 – 61	Fuel Tanks

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for CO, NOx, SO_2, particulate matter (PM), PM-10, PM-2.5, VOCs, and GHGs for the applicable equipment.

Step 1 Identify All Potentially Available Control Options

The Department identifies all available control options for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and

Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, CO, SO_2, particulates, VOC, and GHG emissions from equipment similar to those listed in Table 2-1.

Step 2 Eliminate Technically Infeasible Control Options:
The Department evaluates the technical feasibility of each control option based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control options deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control options in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary
The Department reviews the detailed information in the permit application about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The applicant must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. An applicant proposing to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required.

Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option.

Step 5 Select BACT
To complete the BACT process, the Department must establish enforceable emissions limits for each subject emission unit at the source for each pollutant subject to review. If technological or economic limitations in the application of a measurement methodology to a particulate emissions unit would make an emissions limit infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed. Also, the technology upon which the BACT emissions limit is based should be specified so that they are specific to the individual emissions unit subject to BACT review.

The Department reviewed Gas Treatment Plant's BACT analysis and made BACT determinations for NOx, CO, SO_2, PM, PM-10, PM-2.5, VOC, and GHG for various EUs based on the information submitted by AGDC in their application, information from vendors, suppliers, sub-contractors, RBLC, and a comprehensive internet search.

3.0 COMPRESSOR TURBINES

The GTP will contain six cogeneration natural gas-fired turbines (EUs 1 – 6) for treated gas compression and six cogeneration natural gas-fired turbines (EUs 7 – 12) for CO_2 byproduct compression. The 12 compressor turbines will include supplemental duct burners (EUs 13 through 24) in the exhaust firing natural gas. The duct burners will help increase the heat of the recovery system to cover needs of the process heat medium system. There will be 12 exhaust stacks for the 12 compressor turbines coupled with their respective exhaust duct burners. The emission rates in Section 3 include both the turbine and its accompanying duct burner.

Each of the treated gas compressor turbines EUs 1 – 6 are planned to have a nominal capacity of approximately 42 MW, for a total of 252 MW. The duct burners for EUs 1 – 6 have a high heating value input of approximately 190 MMBtu/hr for each burner. Each of the CO_2 compressor turbines EUs 7 – 12 are planned to have a nominal capacity of approximately 26 MW, for a total of 156 MW. The duct burners for EUs 7 – 12 have a high heating value input of approximately 140 MMBtu/hr for each burner. The compressor turbines will emit CO, NOx, SO_2, PM, PM-10, PM-2.5, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

3.1 NOx

Possible NOx emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-1.

Table 3-1: NOx Controls for Large Combined Cycle & Cogeneration Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Selective Catalytic Reduction	67	2 – 9
Low NOx Burners	3	5 – 25

Step 1 – Identify NOx Control Technologies for Compressor Turbines

From research, the Department identified the following technologies as available for control of NOx emissions from gas-fired combined cycle and cogeneration combustion turbines rated at 25 MW or greater:

(a) Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. The operating temperature of conventional SCR systems ranges from 400 degrees Fahrenheit (°F) to 800°F. High temperature SCR relies on special material reaction grids and can operate at higher temperature ranges between 700°F to 1,075°F. High temperature SCR is most frequently installed on simple cycle turbines. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. In the Department's search of the RBLC database, the majority of large combined cycle and cogeneration natural gas-fired combustion turbines used SCR as the primary control method for NOx emissions and contained a BACT limit of 2 ppmv. Hence, the Department considers SCR a technically feasible control technology for the large cogeneration gas-fired turbines.

(b) Dry Low NOx (DLN)
DLN combustors (marketed under many similar names such as SoLoNOx or DLE) utilize multistage premix combustors where the air and fuel is mixed at a lean (high oxygen) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture avoiding localized "hot spots", both resulting in greatly reduced NOx formation rates. DLN combustors have the potential to reduce NOx emissions by 40 to 60%. Note that DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department considers DLN a technically feasible control technology for the large cogeneration gas-fired turbines.

(c) Water/Steam Injection
Water/steam injection involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NOx formation. Both steam and water injections are capable of obtaining the same level of control. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The main technical consideration is the required purity of the water or steam, which is required to protect the equipment from dissolved solids. Obtaining water or steam of sufficient purity requires the installation of rigorous water treatment and deionization systems, incurring additional costs. Water/steam injection also increases CO emissions as it lowers the combustion temperature. Depending on baseline uncontrolled NOx levels, water or steam injection can reduce NOx by 60% or more.

Water/steam injection is a proven technology for NOx emissions reduction from turbines. However, the arctic environment presents significant challenges to water/steam injection due to cost of water treatment, freezing potential due to cold ambient temperatures, and increased maintenance problems due to accelerated wear in the hot sections of the turbines. Generally speaking the Department considers water/steam injection a technically feasible control technology for the large cogeneration gas-fired turbines.

However, the base model turbine selected by ADGC already comes equipped with DLN technology which is not compatible with water/steam injection, and has lower NOx emission rates than water/steam injection. Additionally, the Department's research did not identify water/steam injection as a technology used to control NOx emissions from large combined cycle or cogeneration turbines installed at any facility in the RBLC database. Hence the Department considers water/steam injection as a technically infeasible control technology for the large cogeneration gas-fired turbines.

(d) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600 °F and 2,100 °F. Because the temperature of combined cycle and cogeneration turbines exhaust gas normally ranges from 800°F to 1,000°F, achieving the required reaction temperature is the main difficulty for application of SNCR to turbines. The Department’s research did not identify SNCR as a technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers SNCR as a technically infeasible control technology for the large cogeneration gas-fired turbines.

(e) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Turbines operate under conditions far more fuel-lean than required to support NSCR. The Department’s research did not identify NSCR as a control technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers NSCR as a technically infeasible control technology for the large cogeneration gas-fired turbines.

(f) SCONOX™
SCONOX™ is a new catalytic absorption technology developed by Goal Line Environmental Technologies, Inc. to treat exhaust gas with a potassium carbonate coated catalyst, reducing NOx to N_2. The catalyst also oxidizes CO to CO_2, and NO and NO_2 to potassium nitrates (KNO_3). The catalyst is regenerated by passing dilute H_2 over it which converts the KNO_2 and KNO_3 to K_2CO_3, water, and N_2. One disadvantage of SCONOX™ is that the catalyst is very sensitive to sulfur in the fuel. For fuel gas sulfur content exceeding 30 ppmv, a sulfur adsorption catalyst must be installed upstream of the SCONOX™ catalyst to remove sulfur. No known installations exist in low ambient temperature settings or on turbine arrangements in industrial settings. The Department’s research did not identify facilities using SCONOX™ to control NOx for turbines. Therefore, the Department considers this technology technically infeasible for the large cogeneration gas-fired turbines.

(g) XONON™

XONON™ is a catalytic technology developed by Catalytica Energy Systems, Inc. and now owned by Kawasaki. XONON™ uses flameless fuel combustion to lower NOx emissions. The combustion chamber of a gas turbine completely contains the XONON™ system. XONON™ completely combusts fuel to produce a high-temperature mixture typically about 2,400 °F. Dilution air is added to shape the temperature profile required at the turbine inlet. General Electric and Solar Turbines are testing this new catalyst technology, and the Department's research did not identify facilities using XONON™. The Department considers XONON™ a technically infeasible control technology for the large cogeneration gas-fired turbines because it is not commercially available.

Step 2 – Eliminate Technically Infeasible NOx Control Options for Compressor Turbines

As explained in Step 1, water/steam injection, SNCR, NSCR, SCONOX™, and XONON™ are not feasible technically technologies to control NO_x emissions from the cogeneration gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining NOx Control Options for Compressor Turbines

The following control technologies have been identified and ranked for control of NOx from the compressor turbines:

(a) SCR	(70% - 90% Control)
(b) DLN	(40% - 60% Control)

Step 4 – Evaluate the Most Effective Controls

SCR is the most common and effective NOx control for large combined cycle and cogeneration turbines. No unusual energy impacts were identified with the addition of SCR to the turbines. Environmental impacts include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system. Neither the ammonia slip nor the waste disposal of the catalyst would preclude the use of SCR as a potential NOx control device.

RBLC Review

A review of similar units in the RBLC indicates that SCR is the principle NOx control technology installed on large combined cycle and cogeneration gas-fired turbines (just under 96% in the RBLC database).

Applicant Proposal

AGDC provided economic analyses using the 6th edition (2002) and 7th edition (2019) of the EPA Cost Control Manual (CCM) for installing SCR on the compressor turbines to demonstrate that it is not economically feasible on these units. AGDC noted that both economic analyses showed the costs for SCR installation to be economically infeasible, especially when using the 6th edition of the EPA CCM which takes into account more site-specific conditions, resulting in higher costs. Summaries of AGDC's cost analyses using the 6th edition of the CCM are shown in Table 3-2 and Table 3-3 for the treated gas and CO_2 compressor turbines respectively, and summaries of AGDC's analyses using the 7th edition of the CCM are shown in Table 3-4 and Table 3-5 for the treated gas and CO_2 compressor turbines respectively.

Table 3-2: AGDC Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 1 – 6)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	22.6	177.8	$9,419,391	$2,524,757	$14,200
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 3-3: AGDC Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 7 – 12)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	16.1	125.7	$8,067,132	$2,053,754	$16,333
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 3-4: AGDC Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 1 – 6)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	23.1	177.7	$9,419,391	$2,013,195	$11,327
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

Table 3-5: AGDC Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 7 – 12)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	16.2	125.7	$6,706,591	$1,437,045	$11,432
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

AGDC contends that the economic analyses indicate the level of NOx reduction from SCR does not justify the use of SCR for the large cogeneration gas-fired turbines based on the excessive cost per ton of NOx removed per year.

AGDC proposes the following as BACT for NOx emissions from the large cogeneration gas-fired turbines:

(a) NOx emissions from the operation of the large cogeneration gas-fired turbines will be controlled with the use of DLN combustors; and

(b) NOx emissions from the large cogeneration gas-fired turbines (turbine + supplemental firing burner) will not exceed 17 ppmv at 15 percent oxygen (@ 15% O_2).

Department Evaluation of BACT for NOx Emissions from Cogeneration Gas Turbines
The Department revised the cost analyses to reflect the current bank prime interest rate of 3.25% and revised the equipment life up to 25 years. The Department included the same assumption used by AGDC that DLN is an inherent design feature of new gas-fired combustion turbines and is therefore considered baseline for determining cost effectiveness. The Department did not modify the other assumptions used by AGDC in the cost analyses, including an approximate 88% NOx control which reduced the NOx concentration from 17 ppmv to 2 ppmv, an unrestricted potential to emit of approximately 200 tpy and 142 tpy for the treated gas and CO_2 compressor turbines respectively, an aqueous ammonia cost of $5.67/gallon delivered to Prudhoe Bay (price quote from Brenntag), and the 0.16 $/kWh for electricity cost (average cost of electricity delivered to industrial customers in Alaska). Summaries of the Department's cost analyses using the 6th edition of the CCM are shown in Table 3-6 and Table 3-7 for the treated gas and CO_2 compressor turbines respectively, and summaries of the Department's analyses using the 7th edition of the CCM are shown in Table 3-8 and Table 3-9 for the treated gas and CO_2 compressor turbines respectively.

Table 3-6: Department Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 1 – 6)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	22.6	177.8	$9,419,391	$2,191,748	$12,327
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 3-7: Department Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 7 – 12)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	16.1	125.7	$8,067,132	$1,768,551	$14,065
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 3-8: Department Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 1 – 6)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	23.1	177.7	$9,419,391	$1,808,561	$10,175
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 3-9: Department Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 7 – 12)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	16.2	125.7	$6,706,591	$1,272,414	$10,123
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analyses using the 6th and 7th editions of the CCM indicates the level of NOx reduction does not justify the use of SCR as BACT for the large cogeneration gas-fired combustion turbines at the Gas Treatment Plant.

Step 5 – Selection of NOx BACT for Compressor Turbines

The Department's finding is that BACT for NOx emissions from the cogeneration gas-fired combustion turbines greater than 25 MW is as follows:

(a) NOx emissions from EUs 1 – 12 shall be controlled by operating and maintaining DLN combustors and good combustion practices at all times the units are in operation;

(b) NOx emissions from EUs 1 – 12 shall not exceed 17 ppmv @ 15% O_2 averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

3.2 CO

Possible CO emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-10.

Table 3-10: CO Control for Large Combined Cycle & Cogeneration Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Oxidation Catalyst	78	0.9 – 15
Good Combustion & Clean Fuel	17	2 – 50

Step 1 – Identify CO Control Technologies for Compressor Turbines

From research, the Department identified the following technologies as available for CO control of large combined cycle and cogeneration natural gas-fired combustion turbines rated at greater than 25 MW:

(a) CO Oxidation Catalyst

Catalytic oxidation is a flue gas control that oxidizes CO and hydrocarbon compounds to carbon dioxide and water vapor in the presence of a noble metal catalyst; no reaction reagent is necessary. The reaction is spontaneous and no reactants are required. Catalytic oxidizers can provide oxidation efficiencies of up to 90% at temperatures between 750°F and 1,000°F; the efficiency of the oxidation temperature quickly deteriorates as the temperature decreases. The temperature of the turbine is expected to exhaust at approximately 1,000°F or less, remaining within the temperature range for CO oxidation catalysts. In the Department's search of the RBLC database, the majority of large combined cycle and cogeneration natural gas-fired combustion turbines used an oxidation catalyst as the primary control method for CO emissions and contained a BACT limit between 1.5 - 3 ppmv. Therefore, the Department considers oxidation catalysts a technically feasible control technology for the large cogeneration gas-fired turbines.

(b) Good Combustion Practices (GCP) and Clean Fuel

GCP typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency;
5. Proper fuel gas supply system designed to minimize effects of contaminants or fluctuations in pressure and flow on the fuel gas delivered.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCP is accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCP and clean fuels a technically feasible control technology for the large cogeneration gas-fired turbines.

(c) SCONOx^{TM}

As discussed in detail in the NOx BACT Section 3.1, SCONOx™ reduces CO emissions by oxidizing the CO to CO_2. This technology combines catalytic conversion of CO with an absorption and regeneration process without using ammonia reagent. SCONOx™ catalyst must operate in a temperature range of 300°F to 700°F, and therefore, turbine exhaust temperature must be reduced through the installation of a cooling system prior to entry to the SCONOx™ system. The Department's research did not identify facilities using SCONOX^{TM} to control CO for turbines. Therefore, the Department considers this technology technically infeasible for the large cogeneration gas-fired turbines.

(d) Non-Selective Catalytic Reduction (NSCR)
NSCR uses a catalyst reaction to reduce CO to CO_2. The catalyst is usually a noble metal. The operating temperature for NSCR system ranges from about 700°F to 1,500°F, depending on the catalyst. NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically less than 1%) to be effective because the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an air-to-fuel (A/F) ratio controller at or close to stoichiometric conditions. The Department's research did not identify NSCR as a control technology used to control CO emissions from turbines installed at any facility in the RBLC database. Therefore, the Department considers NSCR a technically infeasible control technology for the large cogeneration gas-fired turbines.

Step 2 – Eliminate Technically Infeasible CO Control Options for Compressor Turbines
As explained in Step 1, NSCR and SCONOX^{TM} are not feasible technologies to control CO emissions from cogeneration gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining CO Control Options for Compressor Turbines
The following control technologies have been identified and ranked for control of CO from the compressor turbines:

(a) Oxidation Catalyst (90% Control)
(b) GCP & Clean Fuels (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce CO emissions from EUs 1 - 12 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Turbine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the principle CO control technologies used for combined cycle and cogeneration gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to install an oxidation catalyst and maintain good combustion practices for the compressor turbines EUs 1 – 12 as BACT for reducing CO emissions. CO emissions from EUs 1 – 12 will not exceed 5 ppmv @ 15% O_2.

Step 5 –Selection of CO BACT for Compressor Turbines
The Department's finding is that BACT for CO emissions from the cogeneration gas-fired combustion turbines greater than 25 MW is as follows:

(a) CO emissions from EUs 1 – 12 shall be controlled by operating and maintaining an oxidation catalyst and following good combustion practices at all times the units are in operation;

(b) CO emissions from EUs 1 – 12 shall not exceed 5 ppmv @ 15% O_2 averaged over a 3-hour period; and

(c) Initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

3.3 Particulates

Possible particulate emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-11.

Table 3-11: Particulate Control for Large Combined Cycle & Cogeneration Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion & Clean Fuel	70	0.0025 – 0.044

Step 1 – Identify Particulate Control Technologies for Power Generation Turbines

From research, the Department identified the following technologies as available for particulate control of large combined cycle and cogeneration natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Fuel Specifications
Natural gas combustion turbines are among the cleanest fossil-fuel fired power generation equipment commercially available. Particulate emissions from combustion turbines fired with low sulfur natural gas are relatively insignificant and marginally significant using a liquid fuel. Particulate matter in the exhaust of liquid or gas-fired turbines are directly related to the levels of ash and metallic additives in fuel. As such, fuel specifications are the primary method of particulate matter control and are a feasible control technology for the large cogeneration gas-fired turbines.

(b) Good Combustion Practices
As discussed in detail in the CO BACT Section 3.2, Proper management of the combustion process will result in a reduction of particulates. Therefore, good combustion practices is a feasible control option for the large cogeneration gas-fired turbines.

Step 2 – Eliminate Technically Infeasible Particulate Controls for Compressor Turbines

All control technologies identified are technically feasible for cogeneration gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining Particulate Control Options for Compressor Turbines

The following control technologies have been identified and ranked for control of particulates from the power generation turbines:

(a) Good Combustion Practices & Clean Fuels (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls

According to the RBLC, clean fuels and good combustion practices are the applicable controls for particulates for EUs 1 – 12. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only particulate control technologies installed on combined cycle and cogeneration gas-fired turbines larger than 25 MW.

Applicant Proposal

AGDC proposed to use clean fuel and good combustion practices for the compressor turbines EUs 1 – 12 as BACT for reducing particulate emissions. Particulate emissions from EUs 1 – 12 will not exceed 0.0063 lb/MMBtu.

Step 5 – Selection of Particulate BACT for Compressor Turbines

The Department's finding is that BACT for particulate emissions from the cogeneration gas-fired combustion turbines greater than 25 MW is as follows:

(a) Particulate emissions from EUs 1 – 12 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) Particulate emissions from EUs 1 – 12 shall not exceed 0.0063 lb/MMBtu averaged over a 3-hour period; and

(c) Initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

3.4 SO_2

Possible SO_2 emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-12.

Table 3-12: SO_2 Control for Large Combined Cycle & Cogeneration Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits[12] (Sulfur in Fuel)
Good Combustion & Clean Fuel	10	0.75 – 5 gr/100 dscf 12.7 – 84.6 ppmv
No Control	1	2 gr/100 dscf 33.8 ppmv

[12] The RBLC listed the emission limits in grains per 100 dry standard cubic feet (gr/100 dscf), which the Department converted to ppmv sulfur using Galvanic Applied Sciences Inc.'s Sulfur Measurement Handbook stating 1 gr/dscf = 16.92 ppmv sulfur at standard temperature and pressure.

Step 1 – Identify SO_2 Control Technologies for Compressor Turbines
From research, the Department identified the following technologies as available for SO_2 control of large combined cycle and cogeneration natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Good Combustion Practices and Clean Fuels
As discussed in detail in CO BACT Section 3.2, as well as the fuel specifications portion of particulate BACT Section 3.3, GCP and clean fuels is a common technique for controlling SO_2 emissions. SO_2 emissions in the exhaust of liquid or gas-fired turbines are directly related to the levels of sulfur in fuel. As such, fuel specifications are the primary method of SO_2 emissions control and are a feasible control technology for the combustion turbines.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for Compressor Turbines
All control technologies identified are technically feasible for cogeneration gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining SO_2 Control Options for Compressor Turbines
The following control technologies have been identified and ranked for control of SO_2 from the compressor turbines:

(a) Good Combustion Practices & Clean Fuels (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, clean fuels and good combustion practices are the applicable controls for SO_2 emissions for EUs 1 – 12. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only SO_2 emission control technologies installed on large combined cycle and cogeneration gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to use clean fuels and good combustion practices for the power generation turbines EUs 1 – 12 as BACT for reducing SO_2 emissions. AGDC will utilize natural gas in the compressor turbines EUs 1 – 12 with a total sulfur content not to exceed 96 ppmv during the initial phases of operation prior to the natural gas treatment trains becoming operational. Upon completion of the three natural gas treatment trains the total sulfur content of the fuel will not exceed 16 ppmv.

Step 5 –Selection of SO_2 BACT for Compressor Turbines
The Department's finding is that BACT for SO_2 emissions from the cogeneration gas-fired combustion turbines greater than 25 MW is as follows:

(a) SO_2 emissions from EUs 1 – 12 shall be minimized by maintaining good combustion practices and burning natural gas at all times the units are in operation;

(b) Prior to the completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 1 – 12 shall not exceed 96 ppmv;

(c) Upon completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 1 – 12 shall not exceed 16 ppmv; and

(d) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

3.5 VOC

Possible VOC emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-13.

Table 3-13: VOC Control for Large Combined Cycle & Cogeneration Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	13	0.3 – 4 ppmv 0.0018 – 0.004 lb/MMBtu
Oxidation Catalyst	46	0.7 – 5 ppmv 0.0022 – 0.004 lb/MMBtu
No Controls	6	1 – 4 ppmv

Step 1 – Identify VOC Control Technologies for Compressor Turbines

From research, the Department identified the following technologies as available for VOC control of large combined cycle and cogeneration natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Oxidation Catalyst
Oxidation catalyst can control VOC emissions in the exhaust gas with the proper selection of catalyst. The oxidation reaction is spontaneous and does not require addition reagents. Formaldehyde and other organic HAPs can see reductions of 85% to 90%. The Department considers oxidation catalysts a technically feasible control technology for the large cogeneration gas-fired turbines.

(b) Good Combustion Practices
VOC emissions in gas combustion turbines result from incomplete combustion. These VOCs can contain a wide variety of organic compounds, some of which are hazardous air pollutants. VOCs are discharged into the atmosphere when some of the fuel is un-combusted or only partially combusted. VOCs can be trace constituents of the fuel or products of pyrolysis of heavier hydrocarbons in the gas. In that complete combustion will reduce VOC emissions, good combustion practices are a feasible control method for the large cogeneration gas-fired turbines.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Compressor Turbines

All control technologies identified are technically feasible for cogeneration gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining VOC Control Options for Compressor Turbines
The following control technologies have been identified and ranked for control of VOC from the Compressor turbines:

(a) Oxidation Catalyst (85% to 90% Control)
(b) Good Combustion Practices (Less than 85% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce VOC emissions from EUs 1 – 12 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Turbine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the principle VOC control technologies used on combined cycle and cogeneration gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to install an oxidation catalyst and maintain good combustion practices for the compressor turbines EUs 1 – 12 as BACT for reducing VOC emissions. VOC emissions from EUs 1 – 12 will not exceed 0.0074 lb/MMBtu.

Step 5 – Selection of VOC BACT for the Compressor Turbines
The Department's finding is that BACT for VOC emissions from the cogeneration gas-fired combustion turbines greater than 25 MW is as follows:

(a) VOC emissions from EUs 1 – 12 shall be controlled by operating and maintaining an oxidation catalyst and good combustion practices at all times the units are in operation;

(b) VOC emissions from EUs 1 – 12 shall not exceed 0.0022 lb/MMBtu averaged over a 3-hour period (applicant proposal with 70% VOC removal from oxidation catalyst); and

(c) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

3.6 GHG
Possible GHG emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.210: large combined cycle and cogeneration natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 3-14.

Table 3-14: GHG Control for Large Combined Cycle & Cogeneration Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	30	850 – 1800 lb/MWh 112.6 – 151.2 lb/MMBtu
Carbon Capture and Sequestration (CCS)	0	N/A
No Control	5	774 – 1000 MWh

CO_2 and N_2O emissions are produced during natural gas combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, regardless of the firing configuration. CH_4 is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas.

Step 1 – Identify GHG Control Technologies for Power Generation Turbines
From research, the Department identified the following technologies as available for GHG control of large combined cycle and cogeneration natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Thermal Efficiency and the Utilization of Thermal Energy and Electricity
The EPA Guidance states that options that improve the overall efficiency of the source or modification must be evaluated in the BACT analysis. These options can include technologies, processes, and practices at the emitting unit that allows the plant to operate more efficiently. In general, an efficient process requires less fuel for process heat, and therefore reduces the amount of CO_2 produced. In addition to energy efficiency of the individual emitting units, process improvements that impact the facility's higher-energy-using equipment, processes or operations could lead to reductions in emissions. There are a number of cycle configurations of a turbine as well as turbine designs that improves the efficiency of the operation.

1. Simple Cycle Gas-Fired Turbine (Baseline)
   In the baseline case, each turbine would operate in a simple cycle, which includes a single gas turbine to generate power. This configuration uses air as a diluent to reduce combustion flame temperatures. Fuel and air are pre-mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture, which is then delivered to the combustor. The efficient combustion resulting from the process reduces the fuel consumption and CO_2 emissions.

2. Turbine with Waste Heat Recovery (Combined Cycle or Combined Heat and Power)
   In a combined cycle turbine, waste heat recovery units are added to the exhausts of the turbines, and recover previously unused energy to drive a steam turbine generator (STG). In a Combined Heat and Power (also known as cogeneration) turbine, waste heat from the turbine exhaust is put to a productive use such as heating a building, or used for a process that requires heat inputs. Utilizing waste heat in turbines leads to a more energy efficient operation because the additional power produced by the STG and heat produced by the turbine does not require additional fuel consumption.

Besides the STG, this configuration requires additional equipment such as condensers, deaerator, and boiler feed pump, which increases the footprint and the cost of the facility. Furthermore, the additional steam turbine generation in a fixed electrical demand application forces gas turbine load reductions, increasing the gas turbine heat rates, and offsetting CO_2 reduction benefits.

3. Aeroderivative Turbine
Aeroderivative turbines are similar to industrial turbines (also known as heavy duty or frame turbines) except their design is derived from aviation turbines, causing them to be lighter and generally smaller. Aeroderivative turbines have been used in gas compression and electrical power generation operations due to their ability to be shut down and handle load changes quickly. These turbines are also used in the marine industry due to their reduced weight. In addition to being lighter weight than traditional industrial turbines, these turbines are generally more efficient than industrial turbines of comparable size and capacity. This leads to less fuel consumption to achieve the same power output, resulting in a reduction of GHG emissions in the 4% to 12% range.

4. Organic Rankine Cycle (ORC)
ORC uses a refrigerant working fluid that is heated by engine exhaust gas from the natural gas fired turbines, and expands through a turbine connected to the engine shaft. The ORC system involves the same components as in a conventional steam power plant; however, instead of using water as a working fluid, ORC uses a refrigerant with a boiling point lower than that of water, and enables recovery of heat from lower-temperature heat sources. The ORC offers reduced equipment size compared to the steam cycle. This equipment is at their best in air-cooled applications where the heat source is below approximately 400ºF. The heat source for this application is the gas turbine exhaust, and is approximately 800 to 1,000 ºF, which would require an additional thermal fluid loop.

   A disadvantage of the ORC is that, the configuration requires more fuel consumption compared to the steam cycle, and operation when ambient temperature is below 40ºF (approximately 50% of the year) makes the system less efficient. Also, additional heat exchangers may be needed to preheat the ORC working fluid and the combustion air, which would increase the cost and complexity of the system. The Department does not consider ORC as a technically feasible technology for control of GHGs.

(b) Carbon Capture and Sequestration (CCS)
The EPA Guidance classifies CCS as “an add-on pollution control technology that is ‘available’ for facilities emitting CO_2 in large amounts.” AGDC has included a description of CCS, and a review of the technology in their permit application.

CCS is a broad term that includes a number of technologies that involves three general steps: 1) capturing the carbon dioxide directly at its source and compressing it, 2) transporting, and 3) storing it in non-atmospheric reservoirs. Capture, the most energy-intensive of all the processes, can be done either through pre-combustion methods or post-combustion methods. Pre-combustion requires the use of oxygen instead of air to combust the fuel. In general, pre-combustion reduces the energy required and the cost to remove CO_2 emissions from the combustion process. The concentration of CO_2 in the untreated gas stream is higher in pre-combustion capture, thereby requiring less and cheaper equipment. The other method is post-combustion, applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases.

After capture, the CO_2 is compressed to a near-liquid state, and transported via pipeline to a designated storage area. These reservoirs are deep enough for the pressure of the earth to keep it in a liquidized form where it will be sequestered for thousands of years. Depleted oil and gas reservoirs are the most practical places for storing CO_2 emissions that would otherwise be emitted back into the atmosphere. Other options for storage include deep saline formations, un-mineable coal seams, and even offshore storage. The stored CO_2 is expected to remain underground for as long as thousands, even millions of years.

The Department's research did not identify CCS as a control technology used to control GHG emissions from turbines or any other emission unit type installed at any facility in the RBLC database. However, AGDC submitted an economic analysis for CCS on the gas-fired turbines that will be advanced to the next step and evaluated.

(c) Good Combustion Practices (GCP) and Clean Fuels
Discussed in detail in CO BACT Section 3.2, as well as the fuel specifications portion of particulate BACT Section 3.3. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of liquid or gas-fired turbines are directly related to the carbon content in the fuel. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel, and is considered a feasible control technology for the power generation turbines.

Step 2 – Eliminate Technically Infeasible GHG Control Options for Compressor Turbines
As explained in Step 1, ORC is not a feasible technology to control GHG emissions from cogeneration gas-fired turbines larger than 25 MW.

Thermal Efficiency - Aeroderivative turbine: the facility is currently designed to use 12 cogeneration turbines for the treated gas compression and CO_2 compression. Requiring the compressor turbines to be aeroderivative models would fundamentally redefine the source, and is therefore not considered as an option in the BACT analysis.

Step 3 – Rank Remaining GHG Control Options for Compressor Turbines
The following control technologies have been identified and ranked for control of GHG from the compressor turbines:

(a) CCS (80% - 90% Control)
(b) GCP and Clean Fuels (<80% Control)

Step 4 – Evaluate the Most Effective Controls

According to the RBLC, clean fuels and good combustion practices are the applicable controls for GHG emissions for EUs 1 – 12. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only GHG emission control technologies currently installed on combined cycle or and cogeneration gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC provided an economic analysis of the top most effective control technology CCS for a combination of the cogeneration compressor turbines EUs 1 – 12, their associated WHRU EUs 13 – 24, and the simple cycle power generation turbines EUs 25 – 30 to demonstrate that the use of the most effective control (CCS) is not economically feasible. The economic analysis included a study conducted by URS Corporation in 2010 titled, "Alaska Pipeline Project Gas Treatment Plant: CO_2 Capture Study." AGDC noted that the cost for CCS alone for the turbines at the GTP would be more than 3 billion dollars, which is on the order of 50% of the cost of the entire GTP facility. AGDC calculated that assuming 90% control of emissions would avoid 4.2 million tons of CO_2 per year at the cost of more than $900/ton.

AGDC proposed to use clean fuels (natural gas) and good combustion practices for the compressor turbines EUs 1 – 12 as BACT for reducing GHG emissions. GHG emissions from EUs 1 – 12 will not exceed 117.1 lb/MMBtu, which is the carbon dioxide equivalent (CO_2e) emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Department Evaluation of BACT for GHG Emissions from Gas-Fired Turbines
The Department used the provided capital investment cost from the CO_2 Capture Study to create an economic analysis. The Department's economic analysis used the current bank prime interest rate of 3.25%, an equipment life of 25 years, and assumed a 90% control of CO_2 emissions. A summary of the Department's cost analysis for all turbines EUs 1-30 combined is shown in Table 3-15.

Table 3-15: Department Economic Analysis for Technically Feasible GHG Controls (EUs 1 – 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	428,916.6	3,860,249.4	$3,631,800,000	$534,314,775	$138.4
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis, combined with the fact that there are no examples of CCS being used to control GHG emissions from any facility in the RBLC, indicates the level of GHG reduction does not justify the use of CCS as BACT for the turbines at the Gas Treatment Plant.

Step 5 – Selection of GHG BACT for Compressor Turbines
The Department's finding is that BACT for GHG emissions from the cogeneration gas-fired combustion turbines greater than 25 MW is as follows:

(a) GHG emissions from EUs 1 – 12 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation; and

(a) GHG emissions from treated gas compressor turbines EUs 1 – 12 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

4.0 POWER GENERATION TURBINES

The GTP will use six simple cycle natural gas-fired turbines (EUs 25 – 30) to supply power to the facility. Each turbine is planned to have a nominal capacity of approximately 40 MW, for a total of 240 MW. The power generation turbines will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

4.1 NOx

Possible NOx emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-1.

Table 4-1: NOx Controls for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Selective Catalytic Reduction	11	2.5 – 5
Low NOx Burners	38	9 – 25
Water Injection	5	20 – 25

Step 1 – Identify NOx Control Technologies for Power Generation Turbines
From research, the Department identified the following technologies as available for control of NOx emissions from gas-fired simple cycle combustion turbines rated at 25 MW or greater:

(a) Selective Catalytic Reduction (SCR)
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. The operating temperature of conventional SCR systems ranges from 400 degrees Fahrenheit (°F) to 800°F. High temperature SCR relies on special material reaction grids and can operate at higher temperature ranges between 700°F to 1,075°F. High temperature SCR is most frequently installed on simple cycle turbines. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. The Department considers SCR a technically feasible control technology for large simple cycle gas-fired turbines.

(b) Dry Low NOx (DLN)
DLN combustors (marketed under many similar names such as SoLoNOx or DLE) utilize multistage premix combustors where the air and fuel is mixed at a lean (high oxygen) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture avoiding localized “hot spots”, both resulting in greatly reduced NOx formation rates. DLN combustors have the potential to reduce NOx emissions by 40 to 60%. In the Department’s search of the RBLC database, the majority of large simple cycle natural gas-fired combustion turbines used DLN as the primary control method for NOx emissions and contained a BACT limit of 9 parts per million by volume (ppmv). Note that DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department considers DLN a technically feasible control technology for large simple cycle gas-fired turbines.

(c) Water/Steam Injection
Water/steam injection involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NOx formation. Both steam and water injections are capable of obtaining the same level of control. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The main technical consideration is the required purity of the water or steam, which is required to protect the equipment from dissolved solids. Obtaining water or steam of sufficient purity requires the installation of rigorous water treatment and deionization systems, incurring additional costs. Water/steam injection also increases CO emissions as it lowers the combustion temperature. Depending on baseline uncontrolled NOx levels, water or steam injection can reduce NOx by 60% or more. Water/steam injection is a proven technology for NOx emissions reduction from turbines. However, the arctic environment presents significant challenges to water/steam injection due to cost of water treatment, freezing potential due to extreme cold ambient temperatures, and increased maintenance problems due to accelerated wear in the hot sections of the turbines. The Department considers water/steam injection a technically feasible control technology for large simple cycle gas-fired turbines.

(d) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600 °F and 2,100 °F. Because the temperature of simple cycle turbines exhaust gas normally ranges from 800°F to 1,000°F, achieving the required reaction temperature is the main difficulty for application of SNCR to turbines. The Department’s research did not identify SNCR as a technology used to control NOx emissions from

turbines installed at any facility. Hence the Department considers SNCR as a technically infeasible control technology for the large simple cycle gas-fired turbines.

(e) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Turbines operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from turbines installed at any facility. Hence the Department considers NSCR as a technically infeasible control technology for the large simple cycle gas-fired turbines.

(f) SCONOX™
SCONOX™ is a new catalytic absorption technology developed by Goal Line Environmental Technologies, Inc. to treat exhaust gas with a potassium carbonate coated catalyst, reducing NOx to N_2. The catalyst also oxidizes CO to CO_2, and NO and NO_2 to potassium nitrates (KNO_3). The catalyst is regenerated by passing dilute H_2 over it which converts the KNO_2 and KNO_3 to K_2CO_3, water, and N_2. One disadvantage of SCONOX™ is that the catalyst is very sensitive to sulfur in the fuel. For fuel gas sulfur content exceeding 30 ppmv, a sulfur adsorption catalyst must be installed upstream of the SCONOX™ catalyst to remove sulfur. No known installations exist in low ambient temperature settings or on turbine arrangements in industrial settings. The Department's research did not identify facilities using SCONOX™ to control NOx for turbines. Therefore, the Department considers this technology technically infeasible for the large simple cycle gas-fired turbines.

(g) XONON™
XONON™ is a catalytic technology developed by Catalytica Energy Systems, Inc. and now owned by Kawasaki. XONON™ uses flameless fuel combustion to lower NOx emissions. The combustion chamber of a gas turbine completely contains the XONON™ system. XONON™ completely combusts fuel to produce a high-temperature mixture typically about 2,400 °F. Dilution air is added to shape the temperature profile required at the turbine inlet. General Electric and Solar Turbines are testing this new catalyst technology, and the Department's research did not identify facilities using XONON™. The Department considers XONON™ a technically infeasible control technology for the large simple cycle gas-fired turbines because it is not commercially available.

Step 2 – Eliminate Technically Infeasible NOx Control Options for Power Generation Turbines
As explained in Step 1, SNCR, NSCR, SCONOX™, and XONON™ are not feasible technologies to control NO_x emissions from simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining NOx Control Options for Power Generation Turbines

The following control technologies have been identified and ranked for control of NOx from the power generation turbines:

(a) SCR (70% - 90% Control)
(b) DLN (40% - 60% Control)
(c) Water/Steam Injection (20% - 40% Control)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for large simple cycle turbines. No unusual energy impacts were identified with the addition of SCR to the turbines. Environmental impacts include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system. Neither the ammonia slip nor the waste disposal of the catalyst would preclude the use of SCR as a potential NOx control device.

RBLC Review
A review of similar units in the RBLC indicates that DLN is the principle NOx control technology, followed by SCR for large simple cycle gas-fired turbines.

Applicant Proposal
AGDC provided economic analyses using the 6th edition (2002) and 7th edition (2019) of the EPA Cost Control Manual (CCM) for installing SCR on the power generation turbines to demonstrate that it is not economically feasible on these units. AGDC noted that both economic analyses showed the costs for SCR installation to be economically infeasible, especially when using the 6th edition of the EPA CCM which considers more site-specific conditions, resulting in higher costs. Summaries of AGDC's analyses using the 6th and 7th editions of the CCM analyses are shown in Table 4-2 and Table 4-3 respectively.

Table 4-2: AGDC Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 25 – 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	13.4	87.2	$9,412,156	$2,214,974	$25,402
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 4-3: AGDC Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 25 – 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	13.5	87.2	$5,952,307	$1,225,630	$14,056
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

AGDC contends that the economic analyses indicate the level of NOx reduction from SCR does not justify the use of SCR for the large simple cycle gas-fired turbines based on the excessive cost per ton of NOx removed per year.

AGDC proposes the following as BACT for NOx emissions from the large simple cycle gas-fired turbines:

(a) NOx emissions from the operation of the large simple cycle gas-fired turbines will be controlled with the use of DLN combustors; and

(b) NOx emissions from the large simple cycle gas-fired turbines will not exceed 15 ppmv @ 15% O_2.

Department Evaluation of BACT for NOx Emissions from Large Simple Cycle Gas-Fired Turbines

The Department revised the cost analyses to reflect the current bank prime interest rate of 3.25% and revised the equipment life up to 25 years. The Department included the same assumption used by AGDC that DLN is an inherent design feature of new gas-fired combustion turbines and is therefore considered baseline for determining cost effectiveness. The Department did not modify the other assumptions used by AGDC in the cost analyses, including an 86.7% NOx control which reduced the NOx concentration from 15 ppmv to 2 ppmv, an unrestricted potential to emit of 100.6 tpy, an aqueous ammonia cost of $5.67/gallon delivered to Prudhoe Bay (price quote from Brenntag), and the 0.16 $/kWh for electricity cost (average cost of electricity delivered to industrial customers in Alaska). Summaries of the Department's cost analyses using the 6th and 7th editions of the CCM analyses are shown in Table 4-4 and Table 4-5 respectively.

Table 4-4: Department Economic Analysis (6th Edition) for Technically Feasible NOx Controls (EUs 25 – 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	13.4	87.2	$9,412,156	$1,882,220	$21,586
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 4-5: Department Economic Analysis (7th Edition) for Technically Feasible NOx Controls (EUs 25 – 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	13.5	87.2	$5,952,307	$1,081,116	$12,399
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analyses using the 6th and 7th editions of the CCM indicates the level of NOx reduction does not justify the use of SCR as BACT for the large simple cycle gas-fired combustion turbines at the Gas Treatment Plant.

Step 5 – Selection of NOx BACT for Power Generation Turbines
The Department's finding is that BACT for NOx emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) NOx emissions from EUs 25 – 30 shall be controlled by operating and maintaining DLN combustors at all times the units are in operation;

(b) NOx emissions from EUs 25 – 30 shall not exceed 15 ppmv @ 15% O_2 averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

4.2 CO

Possible CO emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-6.

Table 4-6: CO Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Oxidation Catalyst	10	1.5 – 10
Good Combustion & Clean Fuel	30	4 – 29
No Control	1	63

Step 1 – Identify CO Control Technologies for Power Generation Turbines
From research, the Department identified the following technologies as available for CO control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Oxidation Catalyst
Catalytic oxidation is a flue gas control that oxidizes CO and hydrocarbon compounds to carbon dioxide and water vapor in the presence of a noble metal catalyst; no reaction reagent is necessary. The reaction is spontaneous and no reactants are required. Catalytic oxidizers can provide oxidation efficiencies of up to 90% at temperatures between 750°F and 1,000°F; the efficiency of the oxidation temperature quickly deteriorates as the temperature decreases. The temperature of the turbine is expected to exhaust at approximately 1,000°F or less, remaining within the temperature range for CO oxidation catalysts. The Department considers oxidation catalysts a technically feasible control technology for large simple cycle gas-fired turbines.

(b) Good Combustion Practices (GCP) and Clean Fuel
GCP typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency;

5. Proper fuel gas supply system designed to minimize effects of contaminants or fluctuations in pressure and flow on the fuel gas delivered.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCP is accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. In the Department's search of the RBLC database, the majority of large simple cycle natural gas-fired combustion turbines used GCP and clean fuels as the primary control method for CO emissions. Therefore, the Department considers GCP and clean fuels a technically feasible control technology for large simple cycle gas-fired turbines.

(c) SCONOx™
As discussed in detail in the NOx BACT Section 4.1, SCONOx™ reduces CO emissions by oxidizing the CO to CO_2. This technology combines catalytic conversion of CO with an absorption and regeneration process without using ammonia reagent. SCONOx™ catalyst must operate in a temperature range of 300°F to 700°F, and therefore, turbine exhaust temperature must be reduced through the installation of a cooling system prior to entry to the SCONOx™ system. The Department's research did not identify facilities using SCONOX™ to control CO for turbines. Therefore, the Department considers this technology technically infeasible for the large simple cycle gas-fired turbines.

(d) Non-Selective Catalytic Reduction (NSCR)
NSCR uses a catalyst reaction to reduce CO to CO_2. The catalyst is usually a noble metal. The operating temperature for NSCR system ranges from about 700°F to 1,500°F, depending on the catalyst. NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically less than 1%) to be effective because the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an air-to-fuel (A/F) ratio controller at or close to stoichiometric conditions. The Department's research did not identify NSCR as a control technology used to control CO emissions from turbines installed at any facility in the RBLC database. Therefore, the Department considers NSCR a technically infeasible control technology for the large simple cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible CO Control Options for Power Generation Turbines
As explained in Step 1, NSCR and SCONOX™ are not feasible technologies to control CO emissions from simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining CO Control Options for Power Generation Turbines
The following control technologies have been identified and ranked for control of CO from the power generation turbines:

(a) Oxidation Catalyst	(90% Control)
(b) GCP & Clean Fuels	(Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls

An oxidation catalyst will reduce CO emissions from EUs 25 - 30 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Turbine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the principle CO control technologies used for simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC provided an economic analysis of the top most effective control technology (oxidation catalyst) available for the power generation turbines to demonstrate that the use of the most effective control is not economically feasible for the power generation turbines EUs 25 – 30. A summary of the analysis for the power generation turbines is shown in Table 4-7.

Table 4-7: AGDC Economic Analysis for Technically Feasible CO Controls (EUs 25 – 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	19.0	38.0	$3,812,520	$864,117	$22,740
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

AGDC contends that the economic analysis indicates the level of CO reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the power generation turbines EUs 25 – 30 based on the excessive cost per ton of CO removed per year.

AGDC proposes the following as BACT for CO emissions from the large simple cycle gas-fired turbines:

(a) CO emissions from the operation of the power generation turbines (EUs 25 – 30) will be controlled with the use of good combustion practices and clean fuel; and

(b) CO emissions from the power generation turbines (EUs 25 – 30) will not exceed 15 ppmv @ 15% O_2.

Department Evaluation of BACT for CO Emissions from Simple Cycle Gas-Fired Turbines
The Department revised the cost analysis to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, and revised the freight cost to 10% of the purchased equipment costs. A summary of the analyses is shown below:

Table 4-8: Department Economic Analysis for Technically Feasible CO Controls (EUs 25–30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	20.1	40.6	$2,797,498	$421,501	$10,375
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the power generation turbines (EUs 25 – 30) at the GTP.

Step 5 – Selection of CO BACT for Power Generation Turbines
The Department's finding is that BACT for CO emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) CO emissions from EUs 25 – 30 shall be controlled by maintaining good combustion control practices and burning clean fuel at all times the units are in operation;

(b) CO emissions from EUs 25 – 30 shall not exceed 15 ppmv @ 15% O_2 averaged over a 3-hour period; and

(c) Initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

4.3 Particulates
Possible particulate emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-9.

Table 4-9: Particulate Control for Large Simple Cycle Natural Gas Combustion Turbines

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion & Clean Fuel	25	0.0033 – 0.013

Step 1 – Identify Particulate Control Technologies for Power Generation Turbines
From research, the Department identified the following technologies as available for particulate control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Fuel Specifications
Natural gas combustion turbines are among the cleanest fossil-fuel fired power generation equipment commercially available. Particulate emissions from combustion turbines fired with low sulfur natural gas are relatively insignificant and marginally significant using a liquid fuel. Particulate matter in the exhaust of liquid or gas-fired turbines are directly related to the levels of ash and metallic additives in fuel. As such, fuel specifications are the primary method of particulate matter control and are a feasible control technology for the large simple cycle gas-fired turbines.

(b) Good Combustion Practices
As discussed in detail in the CO BACT Section 4.2, Proper management of the combustion process will result in a reduction of particulates. Therefore good combustion practices is a feasible control option for the large simple cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible PM Controls for Power Generation Turbines
All control technologies identified are technically feasible for simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining Particulate Control Options for Power Generation Turbines
The following control technologies have been identified and ranked for control of particulates from the power generation turbines:

(a) GCP & Clean Fuels (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, clean fuels and good combustion practices are the applicable controls for particulates for EUs 25 – 30. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only particulate control technologies installed on simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to use clean fuel and good combustion practices for the power generation turbines EUs 25 – 30 as BACT for reducing particulate emissions. Particulate emissions from EUs 25 – 30 will not exceed 0.0070 lb/MMBtu.

Step 5 – Selection of Particulate BACT for Power Generation Turbines
The Department’s finding is that BACT for particulate emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) Particulate emissions from EUs 25 – 30 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) Particulate emissions from EUs 25 – 30 shall not exceed 0.0070 lb/MMBtu averaged over a 3-hour period (AP-42 Table 3.1-2a, particulate (total) emissions rate for gas-fired turbines); and

(c) Initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

4.4 SO_2

Possible SO_2 emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-10.

Table 4-10: SO_2 Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits[12] (Sulfur in Fuel)
Good Combustion & Clean Fuel	8	1 – 2 gr/100 dscf 16.9 – 33.8 ppmv
No Control	2	1 – 2 gr/100 dscf 16.9 – 33.8 ppmv

Step 1 – Identify SO_2 Control Technologies for Power Generation Turbines

From research, the Department identified the following technologies as available for SO_2 control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Good Combustion Practices and Clean Fuels
As discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3, GCP and clean fuels is a common technique for controlling SO_2 emissions. SO_2 emissions in the exhaust of liquid or gas-fired turbines are directly related to the levels of sulfur in fuel. As such, fuel specifications are the primary method of SO_2 emissions control and are a feasible control technology for the combustion turbines.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for Power Generation Turbines

All control technologies identified are technically feasible for simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining SO_2 Control Options for Power Generation Turbines

The following control technologies have been identified and ranked for control of SO_2 from the power generation Turbines:

(a) Good Combustion Practices and Clean Fuels (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls

According to the RBLC, clean fuels and good combustion practices are the applicable controls for SO_2 emissions for EUs 25 – 30. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only SO_2 emission control technologies installed on simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal

AGDC proposed to use clean fuels and good combustion practices for the power generation turbines EUs 25 – 30 as BACT for reducing SO_2 emissions. AGDC will utilize natural gas in the compressor turbines EUs 1 – 12 with a total sulfur content not to exceed 96 ppmv during the initial phases of operation prior to the natural gas treatment trains becoming operational. Upon completion of the three natural gas treatment trains the total sulfur content of the fuel will not exceed 16 ppmv.

Step 5 – Selection of SO_2 BACT for Power Generation Turbines

The Department's finding is that BACT for SO_2 emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) SO_2 emissions from EUs 25 – 30 shall be minimized by maintaining good combustion practices and burning natural gas at all times the units are in operation;

(b) Prior to the completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 25 – 30 shall not exceed 96 ppmv;

(c) Upon completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 25 – 30 shall not exceed 16 ppmv; and

(d) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

4.5 VOC

Possible VOC emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-11.

Table 4-11: VOC Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	10	1.4 – 5 ppmv 0.0018 – 0.014 lb/MMBtu
Oxidation Catalyst	7	2 – 3 ppmv

Step 1 – Identify VOC Control Technologies for Power Generation Turbines

From research, the Department identified the following technologies as available for VOC control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Oxidation Catalyst
Oxidation catalyst can control VOC emissions in the exhaust gas with the proper selection of catalyst. The oxidation reaction is spontaneous and does not require addition reagents. Formaldehyde and other organic HAPs can see reductions of 85% to 90%. The Department considers oxidation catalysts a technically feasible control technology for large simple cycle gas-fired turbines.

(b) Good Combustion Practices
VOC emissions in gas combustion turbines result from incomplete combustion. These

VOCs can contain a wide variety of organic compounds, some of which are hazardous air pollutants. VOCs are discharged into the atmosphere when some of the fuel is un-combusted or only partially combusted. VOCs can be trace constituents of the fuel or products of pyrolysis of heavier hydrocarbons in the gas. In that complete combustion will reduce VOC emissions, good combustion practices are a feasible control method for large simple cycle gas-fired turbines.

Step 2 – Eliminate Technically Infeasible VOC Controls for Power Generation Turbines
All control technologies identified are technically feasible for simple cycle gas-fired turbines larger than 25 MW.

Step 3 – Rank Remaining VOC Control Options for Power Generation Turbines
The following control technologies have been identified and ranked for control of VOC from the power generation turbines:

(a) Oxidation Catalyst (85% to 90% Control)
(b) Good Combustion Practices (Less than 85% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce VOC emissions from EUs 25 - 30 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Turbine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and oxidation catalysts are the principle VOC control technologies used on simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC proposed to use good combustion practices for the power generation turbines EUs 25 – 30 as BACT for reducing VOC emissions. VOC emissions from EUs 25 – 30 will not exceed 0.0022 lb/MMBtu.

Department Evaluation of BACT for VOC Emissions from Simple Cycle Gas-Fired Turbines
The Department revised the cost analysis to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, and revised the freight cost to 10% of the purchased equipment costs. A summary of the analyses is shown below:

Table 4-12: Department Economic Analysis for Technically Feasible VOC Controls (EUs 25–30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	20.1	40.6	$2,797,498	$421,501	$10,375
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for the power generation turbines (EUs 25 – 30) at the GTP.

Step 5 – Selection of VOC BACT for Power Generation Turbines

The Department's finding is that BACT for VOC emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) VOC emissions from EUs 25 – 30 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(b) VOC emissions from EUs 25 – 30 shall not exceed 0.0022 lb/MMBtu averaged over a 3-hour period (AP-42 Table 3.1-2a, VOC emission rate for gas-fired turbines); and

(c) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

4.6 GHG

Possible GHG emission control technologies for turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.110: large simple cycle natural gas-fired combustion turbines (>25 MW). The search results are summarized in Table 4-13.

Table 4-13: GHG Control for Large Simple Cycle Natural Gas-Fired Combustion Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion & Clean Fuel	11	884 – 1,707 lb/MWh 117.0 – 120.0 lb/MMBtu
Carbon Capture and Sequestration (CCS)	0	N/A
No Control	10	1030 – 1,461 lb/MWh

CO_2 and N_2O emissions are produced during natural gas combustion in gas turbines. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, regardless of the firing configuration. CH_4 is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas.

Step 1 – Identify GHG Control Technologies for Power Generation Turbines

From research, the Department identified the following technologies as available for GHG control of large simple cycle natural gas-fired combustion turbines rated at greater than 25 MW:

(a) Thermal Efficiency and the Utilization of Thermal Energy and Electricity
The EPA Guidance states that options that improve the overall efficiency of the source or modification must be evaluated in the BACT analysis. These options can include technologies, processes, and practices at the emitting unit that allows the plant to operate more efficiently. In general, an efficient process requires less fuel for process heat, and therefore reduces the amount of CO_2 produced. In addition to energy efficiency of the individual emitting units, process improvements that impact the facility's higher-energy-using equipment, processes or operations could lead to reductions in emissions. There are a number of cycle configurations of a turbine as well as turbine designs that improves the efficiency of the operation.

1. Simple Cycle Gas-Fired Turbine (Baseline)
In the baseline case, each turbine would operate in a simple cycle, which includes a single gas turbine to generate power. This configuration uses air as a diluent to reduce combustion flame temperatures. Fuel and air are pre-mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture, which is then delivered to the combustor. The efficient combustion resulting from the process reduces the fuel consumption and CO_2 emissions.

5. Turbine with Waste Heat Recovery (Combined Cycle or Combined Heat and Power)
In a combined cycle turbine, waste heat recovery units are added to the exhausts of the turbines, and recover previously unused energy to drive a steam turbine generator (STG). In a Combined Heat and Power (also known as cogeneration) turbine, waste heat from the turbine exhaust is put to a productive use such as heating a building, or used for a process that requires heat inputs. Utilizing waste heat in turbines leads to a more energy efficient operation because the additional power produced by the STG and heat produced by the turbine does not require additional fuel consumption. Besides the STG, this configuration requires additional equipment such as condensers, deaerator, and boiler feed pump, which increases the footprint and the cost of the facility. Furthermore, the additional steam turbine generation in a fixed electrical demand application forces gas turbine load reductions, increasing the gas turbine heat rates, and offsetting CO_2 reduction benefits.

6. Aeroderivative Turbine
Aeroderivative turbines are similar to industrial turbines (also known as heavy duty or frame turbines) except their design is derived from aviation turbines, causing them to be lighter and generally smaller. Aeroderivative turbines have been used in gas compression and electrical power generation operations due to their ability to be shut down and handle load changes quickly. These turbines are also used in the marine industry due to their reduced weight. In addition to being lighter weight than traditional industrial turbines, these turbines are generally more efficient than industrial turbines of comparable size and capacity. This leads to less fuel consumption to achieve the same power output, resulting in a reduction of GHG emissions in the 4% to 12% range.

7. Organic Rankine Cycle (ORC)
   ORC uses a refrigerant working fluid that is heated by engine exhaust gas from the natural gas fired turbines, and expands through a turbine connected to the engine shaft. The ORC system involves the same components as in a conventional steam power plant; however, instead of using water as a working fluid, ORC uses a refrigerant with a boiling point lower than that of water, and enables recovery of heat from lower-temperature heat sources. The ORC offers reduced equipment size compared to the steam cycle. This equipment is at their best in air-cooled applications where the heat source is below approximately 400ºF. The heat source for this application is the gas turbine exhaust, and is approximately 800 to 1,000 ºF, which would require an additional thermal fluid loop.

   A disadvantage of the ORC is that, the configuration requires more fuel consumption compared to the steam cycle, and operation when ambient temperature is below 40ºF (approximately 50% of the year) makes the system less efficient. Also, additional heat exchangers may be needed to preheat the ORC working fluid and the combustion air, which would increase the cost and complexity of the system. The Department does not consider ORC as a technically feasible technology for control of GHGs.

(b) Carbon Capture and Sequestration
The EPA Guidance classifies CCS as “an add-on pollution control technology that is ‘available’ for facilities emitting CO_2 in large amounts.” AGDC has included a description of CCS, and a review of the technology in their permit application.

CCS is a broad term that includes a number of technologies that involves three general steps: 1) capturing the carbon dioxide directly at its source and compressing it, 2) transporting, and 3) storing it in non-atmospheric reservoirs. Capture, the most energy-intensive of all the processes, can be done either through pre-combustion methods or post-combustion methods. Pre-combustion requires the use of oxygen instead of air to combust the fuel. In general, pre-combustion reduces the energy required and the cost to remove CO_2 emissions from the combustion process. The concentration of CO_2 in the untreated gas stream is higher in pre-combustion capture, thereby requiring less and cheaper equipment. The other method is post-combustion, applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases.

After capture, the CO_2 is compressed to a near-liquid state, and transported via pipeline to a designated storage area. These reservoirs are deep enough for the pressure of the earth to keep it in a liquidized form where it will be sequestered for thousands of years. Depleted oil and gas reservoirs are the most practical places for storing CO_2 emissions that would otherwise be emitted back into the atmosphere. Other options for storage include deep saline formations, un-mineable coal seams, and even offshore storage. The stored CO_2 is expected to remain underground for as long as thousands, even millions of years.

The Department’s research did not identify CCS as a control technology used to control GHG emissions from turbines or any other emission unit type installed at any facility in the RBLC database. However, AGDC submitted an economic analysis for CCS on the gas-fired turbines that will be advanced to the next step and evaluated.

(c) Good Combustion Practices (GCP) and Clean Fuels
Discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of liquid or gas-fired turbines are directly related to the carbon content in the fuel. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel, and is considered a feasible control technology for the power generation turbines.

Step 2 – Eliminate Technically Infeasible GHG Controls for Power Generation Turbines
As explained in Step 1, ORC is not a feasible technology to control GHG emissions from simple cycle gas-fired turbines larger than 25 MW.

Thermal Efficiency - Turbine with Waste Heat Recovery (Combined Cycle or Combined Heat and Power): the facility is currently designed to use six simple cycle turbines to generate power for the GTP. These power generation turbines will be located approximately 1/3 mile away from the processing facility, and there is no additional demand for the recovered waste heat. The process heat needs for the facility are satisfied by separate cogeneration turbines (combined heat and power) used for treated gas compression (EUs 1 – 6) and CO_2 compression (EUs 7 – 12). Additionally, the operating power demand profile for the power generation turbines has more load variance than the mechanical drives, making the control of a WHR system technically difficult with frequent starts and stops or load changes to units which could result in freezing or sub-cooling issues. Therefore, requiring the power generation turbines to include a waste heat recovery system would fundamentally redefine the nature of the proposed stationary source, and is therefore not considered as an option in the BACT analysis.

Thermal Efficiency - Aeroderivative turbine: the facility is currently designed to use six simple cycle turbines rated at 40 MW each to supply power to the GTP. Requiring the compression turbines to be aeroderivative models would fundamentally redefine the project, and is therefore not considered as an option in the BACT analysis.

Step 3 – Rank Remaining GHG Control Options for Power Generation Turbines
The following control technologies have been identified and ranked for control of GHG from the power generation turbines:

(a) CCS (80% - 90% Control)
(b) GCP and Clean Fuels (<80% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, clean fuels and good combustion practices are the applicable controls for GHG emissions for EUs 25 – 30. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only GHG emission control technologies currently installed on simple cycle gas-fired turbines larger than 25 MW.

Applicant Proposal
AGDC provided an economic analysis of the top most effective control technology CCS for a combination of the cogeneration compressor turbines EUs 1 – 12, their associated WHRU EUs 13 – 24, and the simple cycle power generation turbines EUs 25 – 30 to demonstrate that the use of the most effective control (CCS) is not economically feasible. The economic analysis included a study conducted by URS Corporation in 2010 titled, "Alaska Pipeline Project Gas Treatment Plant: CO_2 Capture Study." AGDC noted that the cost for CCS alone for the turbines at the GTP would be more than 3 billion dollars, which is on the order of 50% of the cost of the entire GTP facility. AGDC calculated that assuming 90% control of emissions would avoid 4.2 million tons of CO_2 per year at the cost of more than $900/ton.

AGDC proposed to use clean fuels (natural gas) and good combustion practices for the power generation turbines EUs 25 – 30 as BACT for reducing GHG emissions. GHG emissions from EUs 25 – 30 will not exceed 117.1 lb/MMBtu , which is the CO_2e emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Department Evaluation of BACT for GHG Emissions from Gas-Fired Turbines
The Department used the provided capital investment cost from the CO_2 Capture Study to create an economic analysis. The Department's economic analysis used the current bank prime interest rate of 3.25%, an equipment life of 25 years, and assumed a 90% control of CO_2 emissions. A summary of the Department's cost analysis for all turbines EUs 1-30 combined is shown in Table 4-14.

Table 4-14: Department Economic Analysis for Technically Feasible GHG Controls (EUs 1 – 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
CCS	428,916.6	3,860,249.4	$3,631,800,000	$534,314,775	$138.4
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis, combined with the fact that there are no examples of CCS being used to control GHG emissions from any facility in the RBLC, indicates the level of GHG reduction does not justify the use of CCS as BACT for the turbines at the Gas Treatment Plant.

Step 5 – Selection of GHG BACT for Power Generation Turbines
The Department's finding is that BACT for GHG emissions from the simple cycle gas-fired combustion turbines greater than 25 MW is as follows:

(a) GHG emissions from EUs 25 – 30 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation; and

(b) GHG emissions from EUs 25 – 30 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

5.0 BLACK START AND EMERGENCY DIESEL-FIRED ENGINES

AGDC will have several engines on site, including one 2,500 kW black start diesel generator (EU 39), three 190 kW diesel fire pump engines (EUs 40 - 42), and two emergency diesel generators (EUs 43 and 44) rated at 250 kw and 150 kW respectively. EUs 39 - 44 are all considered limited use diesel-fired engines. The black start, fire pump, and emergency generator engines will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

5.1 NOx

Possible NOx emission control technologies for limited use diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17:110 to 17.190: Large Internal Combustion Engines (>500 hp) and 17:210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-1 and 5-2 respectively.

Table 5-1: NOx Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	3	0.5 - 0.7
Other Add-On Control	1	1.0
Federal Emission Standards	13	3.0 - 6.9
Good Combustion Practices	31	3.0 - 13.5
No Control Specified	60	2.8 - 14.1

Table 5-2: NOx Controls for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	5	2.2 – 4.8
Good Combustion Practices	25	2.0 – 9.5
Limited Operation	4	3.0
No Control Specified	25	2.6 – 5.6

RBLC Review

A review of similar units in the RBLC indicates good combustion practices and Federal emissions standards are the principle NOx control technologies installed on diesel-fired engines. The lowest emission rate listed in the RBLC is 0.5 g/hp-hr for large diesel engines and 2.0 g/hp-hr for small diesel engines.

Step 1 – Identify NOx Control Technologies for Diesel-Fired Engines

From research, the Department identified the following technologies as available for NOx control of diesel engines:

(a) Selective Catalytic Reduction

The theory of SCR was discussed in detail in the NOx BACT Section 3.1 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department considers SCR a technically feasible control technology for both the large and small diesel-fired engines.

(b) Turbocharger and Aftercooler
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NOx formation in the combustion chamber. Today, manufacturers typically design new diesel engines with a turbocharger and aftercooler technology as part of standard equipment. The Department considers turbocharger and aftercooler a technically feasible control technology for both the large and small diesel-fired engines.

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particulate matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

(d) Ignition Timing Retard (ITR)
ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, an increase in particulate matter emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in the particulate matter emissions resulting from ITR, this technology will not be carried forward.

(e) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for both the large and small diesel-fired engines.

(f) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the GTP are considered limited use engines. The Department considers limited operation a technically feasible control technology for both the large and small diesel-fired engines.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the CO BACT Section 3.2 for the combined cycle natural gas-fired turbines and will not be repeated here. The Department considers GCPs a technically feasible control technology for both the large and small diesel-fired engines.

Step 2 – Eliminate Technically Infeasible NOx Control Options for Diesel-Fired Engines
As explained in Step 1, the Department does not consider fuel injection timing retard and ignition timing retard as technically feasible technologies to control NOx emissions from the diesel-fired engines.

Step 3 – Rank Remaining NOx Control Options for Diesel-Fired Engines
The following control technologies have been identified and ranked for control of NOx from the engines:

(a) Limited Operation	(94% Control)
(b) Selective Catalytic Reduction	(90% Control)
(c) Good Combustion Practices	(Less than 40% Control)
(d) Turbocharger and Aftercooler	(6% – 12% Control)
(e) Federal Emission Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for diesel-fired engines. Environmental impacts include the SCR system increasing exhaust back pressure which decreases the engine's efficiency requiring additional fuel consumption, the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principle NOx control technology used on diesel-fired engines.

Applicant Proposal
AGDC provided economic analyses of the top most effective control technology SCR with limited operation of 500 hours per year assumed for each engine to demonstrate that the use of the most effective control (SCR) is not economically feasible for these limited use diesel engines. A summary of the analyses for the black start diesel generator EU 39 can be found in Table 5-3, the main firewater pumps (EUs 40 – 42) in Table 5-4, the dormitory emergency diesel generator EU 43 in Table 5-5, and the communications tower emergency diesel generator EU 44 in Table 5-6.

Table 5-3: AGDC Economic Analysis for Technically Feasible NOx Controls (EU 39)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.41	5.43	$204,055	$291,091	$53,580
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-4: AGDC Economic Analysis for Technically Feasible NOx Controls (EUs 40 – 42)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.03	0.37	$67,474	$42,114	$115,309
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-5: AGDC Economic Analysis for Technically Feasible NOx Controls (EU 43)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.04	0.49	$67,474	$47,096	$96,775
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-6: AGDC Economic Analysis for Technically Feasible NOx Controls (EU 44)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.02	0.29	$67,474	$39,242	$134,393
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

AGDC contends that the economic analyses indicate the level of NOx reduction from SCR does not justify the use of SCR for the limited use diesel engines based on the excessive cost per ton of NOx removed per year.

AGDC proposes the following as BACT for NOx emissions from the diesel engines:

(a) NOx emissions from the operation of the diesel engines EUs 39 - 44 will be controlled through limited operation of 500 hours per 12-month rolling period per unit and by utilizing good combustion practices;

(b) NOx emissions from the black start diesel generator EU 39 will not exceed 3.26 g/hp-hr @ 15% O_2;

(c) NOx emissions from the diesel firewater pump engines EUs 40 – 42 will not exceed 3.56 g/hp-hr @ 15% O_2; and

(d) NOx emissions from the emergency diesel engines EUs 43 and 44 will not exceed 3.54 g/hp-hr @ 15% O_2.

Department Evaluation of BACT for NOx Emissions from Diesel-Fired Engines

The Department revised the cost analyses to reflect the equipment life revised to a 25 year lifespan, to account for differences in PTE, and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analyses for the black start diesel generator EU 39 can be found in Table 5-7, the main firewater pumps (EUs 40 – 42) in Table 5-8, the dormitory emergency diesel generator EU 43 in Table 5-9, and the communications tower emergency diesel generator EU 44 in Table 5-10.

Table 5-7: Department Economic Analysis for Technically Feasible NOx Controls (EU 39)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.51	6.79	$204,055	$283,805	$41,802
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-8: Department Economic Analysis for Technically Feasible NOx Controls (EUs 40-42)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.03	0.46	$67,474	$39,729	$87,022
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-9: Department Economic Analysis for Technically Feasible NOx Controls (EU 43)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.05	0.61	$67,474	$44,711	$73,499
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-10: Department Economic Analysis for Technically Feasible NOx Controls (EU 44)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.03	0.36	$67,474	$36,856	$100,978
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction does not justify the use of SCR as BACT for any of the limited use diesel engines at the Gas Treatment Plant.

Step 5 – Selection of NOx BACT for Diesel-Fired Engines
The Department's finding is that BACT for NOx emissions from the limited use diesel engines is as follows:

(a) NOx emissions from the operation of the diesel engine EUs 39 - 44 shall be controlled by maintaining good combustion practices at all times the units are in operation;
(b) Limit operation of the diesel-fired engines EUs 39 – 44 to no more than 500 hours per 12-month rolling period per engine;
(c) NOx emissions from the black start diesel generator EU 39 will not exceed 3.3 g/hp-hr @ 15% O_2 (EPA Tier 4 Final, includes 25% not to exceed factor of safety);
(d) NOx emissions from the diesel firewater pump engines EUs 40 – 42 will not exceed 3.6 g/hp-hr @ 15% O_2 (95% of NMHC + NOx from Table 4 of NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);
(e) NOx emissions from the emergency diesel engines EUs 43 and 44 will not exceed 3.6 g/hp-hr @ 15% O_2 (95% of NMHC + NOx from EPA Tier 3, includes 25% not to exceed factor of safety); and
(f) Initial compliance with the proposed NOx emission limits will be demonstrated by purchasing engines certified to meet the appropriate EPA Tier emissions standards.

5.2 CO
Possible CO emission control technologies for limited use diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-11 and 5-12 respectively.

Table 5-11: CO Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Oxidation Catalyst	1	0.13
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	56	0.31 - 8.5
Operational Limit	1	2.6
No Control Specified	15	0.26 – 2.6

Table 5-12: CO Controls for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	43	0.53 - 3.7
Operational Limit	2	2.6 - 4.1
Turbocharger & Intercooler	1	0.45
No Control Specified	16	0.5 - 3.1

Step 1 – Identify CO Control Technologies for Diesel-Fired Engines
From research, the Department identified the following technologies as available for CO control of diesel-fired engines:

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines. Oxidation catalysts oxidize CO and hydrocarbon compounds to carbon dioxide and water vapor. The reaction is spontaneous and no reactants are required. CO catalysts can achieve up to 90% reduction in CO emissions. The Department considers oxidation catalysts to be a technically feasible control technology for both the large and small sized diesel engines.

(b) Good Combustion Practices (GCP) and clean fuel
The theory of GCPs and clean fuel was discussed in detail in CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are commonly used to control CO emissions for diesel engines. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for both the large and small sized diesel engines.

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the GTP are considered limited use engines. The Department considers limited operation a technically feasible control technology for both the large and small diesel-fired engines.

(d) Federal Emission Standards
RBLC CO determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards of Subpart IIII as a technically feasible control technology for both the large and small diesel-fired engines.

Step 2 – Eliminate Technically Infeasible CO Control Options for Diesel-Fired Engines
All of the control technologies identified are technically feasible for the diesel engines.

Step 3 – Rank Remaining CO Control Options for Diesel-Fired Engines
The following control technologies have been identified and ranked for control of CO from the diesel-fired engines:

(a) Limited Operation	(94% Control)
(b) Oxidation Catalyst	(90% Control)
(c) Good Combustion Practices	(Less than 90% Control)
(d) Federal Emission Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls

An oxidation catalyst will reduce CO emissions from EUs 39 - 44 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review

A review of similar units in the RBLC indicates good combustion practices with clean fuel and following Federal emissions standards are the principle CO control for both large and small sized diesel engines.

Applicant Proposal

AGDC provided economic analyses of the most effective control technology - oxidation catalyst with limited operation of 500 hours per year assumed for each engine to demonstrate that the use of an oxidation catalyst is not economically feasible for these limited use diesel engines. A summary of the analyses for the black start diesel generator EU 39 can be found in Table 5-13, the main firewater pumps (EUs 40 – 42) in Table 5-14, the dormitory emergency diesel generator EU 43 in Table 5-15, and the communications tower emergency diesel generator EU 44 in Table 5-16.

Table 5-13: AGDC Economic Analysis for Technically Feasible CO Controls (EU 39)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	1.75	4.09	$25,507	$6,857	$1,677
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-14: AGDC Economic Analysis for Technically Feasible CO Controls (EUs 40 – 42)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.11	0.25	$25,507	$6,857	$27,343
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-15: AGDC Economic Analysis for Technically Feasible CO Controls (EU 43)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.14	0.34	$25,507	$6,857	$20,237
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-16: AGDC Economic Analysis for Technically Feasible CO Controls (EU 44)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.09	0.20	$25,507	$6,857	$33,879
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

AGDC contends that the economic analysis indicates the level of CO reduction from an oxidation catalyst does not justify the use of an oxidation catalyst for the engine EUs 40 - 44 based on the excessive cost per ton of CO removed per year. For the black start diesel engine EU 39, AGDC contends that the installation of an oxidation catalyst may be cost effective, but that the only case of an oxidation catalyst found in the RBLC for the same diesel engine included SCR to address NOx control with the additional benefit of CO reduction associated with an integrated oxidation catalyst in the SCR control system. AGDC contends that this is not representative of the situation of their black start diesel generator and therefore recommends good combustion practices and clean fuels as BACT for all of their limited use diesel engines.

AGDC proposes the following as BACT for CO emissions from the diesel engines:

(a) CO emissions from the operation of the diesel engines EUs 39 - 44 shall be controlled through limited operation of 500 hours per 12-month rolling period per unit and by maintaining good combustion control practices at all times the units are in operation;

(b) CO emissions from the black start diesel generator EU 39 will not exceed 3.26 g/hp-hr @ 15% O_2;

(c) NOx emissions from the diesel firewater pump engines EUs 40 – 42 will not exceed 3.25 g/hp-hr @ 15% O_2; and

(d) NOx emissions from the emergency diesel engines EUs 43 and 44 will not exceed 3.26 g/hp-hr @ 15% O_2.

Department Evaluation of BACT for CO Emissions from Diesel-Fired Engines

The Department revised the cost analyses to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan, to account for differences in PTE and greater reduction efficiency achievable with catalytic oxidation, and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analyses for the black start diesel generator EU 39 can be found in Table 5-17, the main firewater pumps (EUs 40 – 42) in Table 5-18, the dormitory emergency diesel generator EU 43 in Table 5-19, and the communications tower emergency diesel generator EU 44 in Table 5-20.

Table 5-17: Department Economic Analysis for Technically Feasible CO Controls (EU 39)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	1.54	6.15	$25,507	$5,956	$968
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-18: Department Economic Analysis for Technically Feasible CO Controls (EUs 40-42)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.09	0.38	$25,507	$5,956	$15,711
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-19: Department Economic Analysis for Technically Feasible CO Controls (EU 43)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.13	0.51	$25,507	$5,956	$11,679
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-20: Department Economic Analysis for Technically Feasible CO Controls (EU 44)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.08	0.31	$25,507	$5,956	$19,466
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for diesel engine EUs 40 - 44. However, the Department finds that the removal cost of $968 per ton for the installation of an oxidation catalyst on the black start generator EU 39 is reasonable, and the RBLC does contain an example of a large diesel engine with oxidation catalyst used to control CO emissions.

Step 5 – Selection of CO BACT for Diesel-Fired Engines

The Department's finding is that BACT for CO emissions from the limited use diesel engines is as follows:

(a) CO emissions from the operation of the black start diesel engine EU 39 shall be controlled by operating and maintaining an oxidation catalyst at all times the unit is in operation;

(b) CO emissions from the operation of the diesel engines EUs 40 - 44 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(c) Limit operation of the diesel-fired engines EUs 39 – 44 to no more than 500 hours per 12-month rolling period per engine;

(d) CO emissions from the black start diesel generator EU 39 will not exceed 3.3 g/hp-hr @ 15% O_2 (EPA Tier 4 Final, includes 25% not to exceed factor of safety);

(e) CO emissions from the diesel firewater pump engines EUs 40 – 42 will not exceed 3.3 g/hp-hr @ 15% O_2 (Table 4 from NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);

(f) CO emissions from the emergency diesel engines EUs 43 and 44 will not exceed 3.3 g/hp-hr @ 15% O_2 (EPA Tier 3, includes 25% not to exceed factor of safety);

(g) For the black start diesel engine EU 39, initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EU will comply with the BACT limit; and

(h) For EUs 40 – 44, initial compliance with the proposed CO emission limits will be demonstrated by purchasing engines certified to meet the appropriate EPA Tier emissions standards.

5.3 Particulates

Possible particulate emission control technologies for limited use diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-21 and 5-22 respectively.

Table 5-21: Particulate Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Diesel Particulate Filter	2	0.15
Federal Emission Standards, Good Combustion Practices, & Clean Fuel	113	0.015 – 0.43
Operational Limit	2	0.15
No Control Specified	32	0.025 – 0.32

Table 5-22: Particulate Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Diesel Particulate Filter	2	0.15
Federal Emission Standards, Good Combustion Practices, & Clean Fuel	89	0.075 – 0.40
Operational Limit	2	0.15
No Control Specified	32	0.11 – 1.0

Step 1 – Identify Particulate Control Technologies for Diesel-Fired Engines

From research, the Department identified the following technologies as available for particulate control of diesel engines:

(a) Diesel Particulate Filter (DPF)
DPFs are a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. The Department considers DPF a technically feasible control technology for the diesel-fired engines.

(b) Diesel Oxidation Catalyst (DOC)
DOC can reportedly reduce PM-2.5 emissions by 30% and PM emissions by 50%. A DOC is a form of “bolt on” technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. The Department considers DOC a technically feasible control technology for the diesel-fired engines.

(c) Positive Crankcase Ventilation
Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NOx formation. The Department considers positive crankcase ventilation a technically feasible control technology for the diesel-fired engines.

(d) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel as a feasible control technology for the diesel-fired engines.

(e) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. The Department considers low ash diesel a technically feasible control technology for the diesel-fired engines.

(f) Federal Emission Standards
RBLC PM-2.5 determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers NSPS Subpart IIII a technically feasible control technology for the diesel-fired engines.

(g) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the GTP are considered limited use engines. The Department considers limited operation a technically feasible control technology for the diesel-fired engines.

(h) Good Combustion Practices
As discussed in detail in the CO BACT Section 4.2, Proper management of the combustion process will result in a reduction of particulates. The Department considers good combustion practices a technically feasible control technology for the diesel-fired engines.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for Diesel-Fired Engines
All control technologies identified are technically feasible to control particulate emissions from the diesel engines.

Step 3 – Rank Remaining Particulate Control Options for Diesel-Fired Engines
The following control technologies have been identified and ranked for control of particulate emissions from the diesel engines.

(a) Limited Operation	(94% Control)
(b) Diesel Particulate Filters	(85% Control)
(c) Good Combustion Practices	(Less than 40% Control)
(d) Diesel Oxidation Catalyst	(30% Control)
(e) Low Ash Diesel	(25% Control)
(f) Positive Crankcase Ventilation	(10% Control)
(g) Federal Emission Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls
Limited operation and diesel particulate filters will reduce particulate emissions from EUs 39 - 44 while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that Federal emission standards, good combustion practices, and burning of ULSD fuel are the principle particulate control technologies installed on diesel engines.

Applicant Proposal
AGDC provided economic analyses of the top most effective control technology DPF with limited operation of 500 hours per year assumed for each engine to demonstrate that the use of a DPF is not economically feasible for these limited use diesel engines. A summary of the analyses for the black start diesel generator EU 39 can be found in Table 5-23, the main firewater pumps (EUs 40 – 42) in Table 5-24, the dormitory emergency diesel generator EU 43 in Table 5-25, and the communications tower emergency diesel generator EU 44 in Table 5-26.

Table 5-23: AGDC Economic Analysis for Feasible Particulate Controls (EU 39)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.01	0.06	$308,893	$57,884	$958,085
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-24: AGDC Economic Analysis for Feasible Particulate Controls (EUs 40 – 42)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	<0.01	0.02	$19,022	$3,565	$191,617
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-25: AGDC Economic Analysis for Feasible Particulate Controls (EU 43)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	<0.01	0.02	$25,489	$4,776	$192,903
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

Table 5-26: AGDC Economic Analysis for Feasible Particulate Controls (EU 44)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	<0.01	0.01	$15,293	$2,866	$192,903
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

AGDC contends that the economic analyses indicate the level of particulate emissions reduction from a DPF does not justify the use of DPF for the limited use diesel engines based on the excessive cost per ton of particulate emissions removed per year.

AGDC proposes the following as BACT for particulate emissions from the diesel-fired engines:

(a) Particulate emissions from the operation of the diesel engines EUs 39 - 44 shall be controlled through limited operation of 500 hours per 12-month rolling period per unit and by maintaining good combustion control practices;

(b) Particulate emissions from the black start diesel generator EU 39 will not exceed 0.0375 g/hp-hr @ 15% O_2;

(c) Particulate emissions from the diesel firewater pump engines EUs 40 – 42 will not exceed 0.188 g/hp-hr @ 15% O_2; and

(d) Particulate emissions from the emergency diesel engines EUs 43 and 44 will not exceed 0.186 g/hp-hr @ 15% O_2.

Department Evaluation of BACT for Particulate Emissions from Diesel-Fired Engines
The Department revised the cost analyses to reflect the equipment life revised to a 25 year lifespan, to account for differences in PTE, and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analyses for the black start diesel generator EU 39 can be found in Table 5-27, the main firewater pumps (EUs 40 – 42) in Table 5-28, the dormitory emergency diesel generator EU 43 in Table 5-29, and the communications tower emergency diesel generator EU 44 in Table 5-30.

Table 5-27: Department Economic Analysis for Feasible Particulate Controls (EU 39)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.01	0.09	$308,893	$46,964	$518,222
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-28: Department Economic Analysis for Feasible Particulate Controls (EUs 40-42)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	<0.01	0.02	$19,022	$2,892	$124,373
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-29: Department Economic Analysis for Feasible Particulate Controls (EU 43)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	<0.01	0.03	$25,489	$3,875	$125,208
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-30: Department Economic Analysis for Feasible Particulate Controls (EU 44)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	<0.01	0.02	$15,293	$2,325	$125,208
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of particulate emissions reduction does not justify the use of a DPF as BACT for any of the limited use diesel engines at the Gas Treatment Plant.

Step 5 – Selection of Particulate BACT for Diesel-Fired Engines
The Department's finding is that BACT for particulate emissions from the limited use diesel engines is as follows:

(a) Particulate emissions from the operation of the diesel engine EUs 39 - 44 shall be controlled by maintaining good combustion practices and burning ULSD fuel at all times the units are in operation;

(b) Limit operation of the diesel-fired engines EUs 39 – 44 to no more than 500 hours per 12-month rolling period per engine;

(c) Particulate emissions from the black start diesel-fired generator EU 39 will not exceed 0.045 g/hp-hr @ 15% O_2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety);

(d) Particulate emissions from the diesel firewater pump engines EUs 40 – 42 will not exceed 0.19 g/hp-hr @ 15% O_2 (Table 4 of NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);

(e) Particulate emissions from the emergency diesel engines EUs 43 and 44 will not exceed 0.19 g/hp-hr @ 15% O_2 (EPA Tier 3, includes 25% not to exceed factor of safety); and

(f) Initial compliance with the proposed particulate emission limits will be demonstrated by purchasing engines certified to meet the appropriate EPA Tier emissions standards.

5.4 SO_2
Possible SO_2 emission control technologies for limited use diesel-fired engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-31 and 5-32 respectively.

Table 5-31: SO_2 Controls for Large Diesel Engines

Control Technology	Number of Determinations	Emission Limits (sulfur content in fuel, ppmw)
Ultra-Low Sulfur Diesel, Limited Operations, and Good Combustion Practices	27	≤15 – 500

Table 5-32: SO_2 Controls for Small Diesel Engines

Control Technology	Number of Determinations	Emission Limits (sulfur content in fuel, ppmw)
Ultra-Low Sulfur Diesel, Limited Operations, and Good Combustion Practices	21	≤15 – 500

Step 1 – Identify SO_2 Control Technologies for Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel-fired engines:

(a) Ultra-Low Sulfur Diesel (ULSD) and Federal Emission Standards
SO_2 emissions in the exhaust of fuel-fired engines are directly related to the levels of sulfur in fuel. As such, fuel specifications are the primary method of controlling SO_2 emissions in engines. ULSD has a maximum sulfur content of 15 ppm (0.0015 percent by weight). The federal emission standards require all diesel-fired engines subject to NSPS Subpart IIII with a displacement of less than 30 liters per cylinder to burn ULSD (40 C.F.R. 60.4207(b)). Therefore, the Department considers ULSD a technically feasible control technology for the diesel-fired engines.

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the diesel-fired engines.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the CO BACT Section 4.2 for simple cycle turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired engines.

Step 2 – Eliminate Technically Infeasible SO_2 Control Technologies for the Diesel Engines
All identified control technologies identified are technically feasible for the diesel-fired engines.

Step 3 – Rank Remaining SO_2 Control Technologies for Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the diesel-fired engines.

(a) ULSD (including Federal Standards) (99% Control)
(b) Limited Operation (94% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, ULSD and good combustion practices are the applicable controls for SO_2 emissions for the diesel engines EUs 39 – 44. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use ULSD, limit operations of each engine to 500 hours per 12-month rolling period per unit, and maintain good combustion control practices for the limited use diesel engines EUs 39 – 44 as BACT for reducing SO_2 emissions.

Step 5 – Selection of SO_2 BACT for Diesel-Fired Engines

The Department's finding is that BACT for SO_2 emissions from the limited use diesel-fired engines is as follows:

(a) SO_2 emissions from the operation of the diesel-fired engines EUs 39 – 44 shall be controlled by only combusting ULSD (sulfur content in fuel of less than or equal to 15 ppmw) at all times the units are in operation;

(b) Limit operation of the diesel-fired engines EUs 39 – 44 to no more than 500 hours per 12-month rolling period per engine;

(c) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(d) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

5.5 VOC

Possible VOC emission control technologies for limited use diesel-fired engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-33 and 5-34 respectively.

Table 5-33: VOC Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Oxidation Catalyst	1	0.21
NSPS IIII	12	0.03 – 0.3
Good Combustion Practices	17	0.015 – 1.0
No Control Specified	26	0.07 – 0.32

Table 5-34: VOC Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	9	0.15 – 0.37
Good Combustion Practices	13	0.05 - 1.6
No Control Specified	8	0.15 - 1.14

Step 1 – Identify VOC Control Technologies for Diesel-Fired Engines

From research, the Department identified the following technologies as available for VOC control of diesel-fired engines:

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines. Oxidation catalysts oxidize CO and hydrocarbon compounds to carbon dioxide and water vapor. The reaction is spontaneous and no reactants are required. The Department considers oxidation

catalysts to be a technically feasible control technology for both the large and small sized diesel engines.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs are commonly used to control VOC emissions for diesel engines. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for both the large and small sized diesel engines.

(c) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. As stated above in Section 5.0, all of the diesel-fired engines at the GTP are considered limited use engines. The Department considers limited operation a technically feasible control technology for both the large and small diesel-fired engines.

(d) Federal Emission Standards
RBLC VOC determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for both the large and small diesel-fired engines.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Diesel-Fired Engines
All of the control technologies identified are technically feasible for the diesel engines.

Step 3 – Rank Remaining VOC Control Options for Diesel-Fired Engines
The following control technologies have been identified and ranked for control of VOCs from the diesel-fired engines:

(a) Limited Operation	(94% Control)
(b) Oxidation Catalyst	(90% Control)
(c) Good Combustion Practices	(Less than 90% Control)
(d) Federal Emissions Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce VOC emissions from EUs 39 - 44 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and federal emission standards are the principle VOC control technologies used on small and large diesel engines, with one example of a large diesel engine using an oxidation catalyst.

Applicant Proposal
AGDC proposed to use good combustion practices, limit operations of each engine to 500 hours per year, and install engines certified to meet NSPS Subpart IIII as BACT for VOC emissions. Assuming that 5% of the total NOx plus NMHC (non-methane hydrocarbons) emissions are VOC emissions, this equates to the following emissions rates:

(a) Limit non-emergency operation of the diesel-fired engines EUs 39 – 44 to no more than 500 hours per 12-month rolling period for each engine, for maintenance checks and readiness testing;

(b) VOC emissions from the black start diesel generator EU 39 will not exceed 0.178 g/hp-hr @ 15% O_2;

(c) VOC emissions from the diesel firewater pump engines EUs 40 – 42 will not exceed 0.188 g/hp-hr @ 15% O_2; and

(d) VOC emissions from the emergency diesel engines EUs 43 and 44 will not exceed 0.186 g/hp-hr @ 15% O_2.

Department Evaluation of BACT for VOC Emissions from Diesel-Fired Engines
The Department revised the cost analyses to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan, to account for differences in PTE and greater reduction efficiency achievable with catalytic oxidation, and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analyses for the black start diesel generator EU 39 can be found in Table 5-35, the main firewater pumps (EUs 40 – 42) in Table 5-36, the dormitory emergency diesel generator EU 43 in Table 5-37, and the communications tower emergency diesel generator EU 44 in Table 5-38.

Table 5-35: Department Economic Analysis for Technically Feasible VOC Controls (EU 39)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	1.54	6.15	$25,507	$5,956	$968
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-36: Department Economic Analysis for Technically Feasible VOC Controls (EUs 40-42)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.09	0.38	$25,507	$5,956	$15,711
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-37: Department Economic Analysis for Technically Feasible VOC Controls (EU 43)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.13	0.51	$25,507	$5,956	$11,679
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 5-38: Department Economic Analysis for Technically Feasible VOC Controls (EU 44)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.08	0.31	$25,507	$5,956	$19,466
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for diesel engine EUs 40 - 44. However, the Department finds that the removal cost of $968 per ton for the installation of an oxidation catalyst on the black start generator EU 39 is reasonable, and the RBLC does contain an example of a large diesel engine with oxidation catalyst used to control VOC emissions.

Step 5 – Selection of VOC BACT for Diesel-Fired Engines

The Department's finding is that BACT for VOC emissions from the limited use diesel-fired engines is as follows:

(a) VOC emissions from the operation of the black start diesel engine EU 39 shall be controlled by operating and maintaining an oxidation catalyst at all times the unit is in operation;

(b) VOC emissions from the operation of the diesel-fired engines EUs 40 – 44 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(c) Limit operation of the diesel-fired engines EUs 39 – 44 to no more than 500 hours per 12-month rolling period per engine;

(d) VOC emissions from the black start diesel-fired generator EU 39 will not exceed 0.18 g/hp-hr @ 15% O_2 (EPA Tier 4 Final, includes 25% not to exceed factor of safety);

(e) VOC emissions from the diesel firewater pump engines EUs 40 – 42 will not exceed 0.19 g/hp-hr @ 15% O_2 (5% of NOx + NMHC value from Table 4 from NSPS Subpart IIII, also equivalent to EPA Tier 3, includes 25% not to exceed factor of safety);

(f) VOC emissions from the emergency diesel-fired engines EUs 43 and 44 will not exceed 0.19 g/hp-hr @ 15% O_2 (5% of NOx + NMHC value from EPA Tier 3, includes 25% not to exceed factor of safety); and

(g) Initial compliance with the proposed VOC emission limits will be demonstrated by purchasing engines certified to meet the appropriate EPA Tier emissions standards.

5.6 GHG

Possible GHG emission control technologies for limited use diesel-fired engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 to 17:190: Large Internal Combustion Engines (>500 hp) and 17.210: Small Fuel Oil-Fired Internal Combustion Engines (<500 hp). The search results for the diesel engines greater than 500 hp and smaller than 500 hp are contained in Tables 5-39 and 5-40 respectively.

Table 5-39: GHG Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Federal Emission Standards	6	37 – 432 tpy
Good Combustion Practices	21	72 – 1,299,630 tpy
No Control Specified	14	14 – 7,194 tpy 162.8 – 163.6 lb/MMBtu

Table 5-40: GHG Control for Small Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	26	0.29 – 3,083 tpy
NSPS IIII	3	10 – 72 tpy
Limited Operation	5	5 – 58 tpy
No Control Specified	7	91 – 516 tpy 162.9 – 164.9 lb/MMBtu

Step 1 – Identify GHG Control Technologies for Diesel-Fired Engines

From research, the Department identified the following technologies as available for GHG control of diesel-fired engines:

(a) Carbon Capture and Storage
CCS was discussed in detail in the GHG BACT Section 4.6 for simple cycle turbines, and will not be repeated here. The Department’s research did not identify CCS as a control technology used to control GHG emissions from diesel-fired engines or any other emission unit type installed at any facility in the RBLC database. Additionally, the Department performed an economic analysis for CCS on the turbines EUs 1 – 30 at the GTP and found the costs to economically infeasible. Therefore, the Department considers this technology to be both technologically and economically infeasible for controlling GHG emissions from the diesel-fired engines.

(b) Good Combustion Practices
Discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of engines are directly related to the carbon content in the fuel. Good combustion practices are considered a feasible control technology for the diesel-fired engines.

Step 2 – Eliminate Technically Infeasible GHG Control Options for Diesel-Fired Engines
As explained in Step 1, CCS is not considered a technically feasible technology to control GHG emissions from diesel-fired engines.

Step 3 – Rank Remaining GHG Control Options for Diesel-Fired Engines
AGDC has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices are the applicable controls for GHG emissions for EUs 39 – 44. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principle control method for GHG from diesel-fired engines.

Applicant Proposal
AGDC proposed to use good combustion practices and limited operation of 500 hours per 12-month rolling period for each engine for EUs 39 - 44 as BACT for reducing GHG emissions. GHG emissions from EUs 39 – 44 will not exceed 163.6 lb/MMBtu, which is the CO_2e emissions rates for burning diesel fuel in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Step 5 – Selection of GHG BACT for Diesel-Fired Engines
The Department's finding is that BACT for GHG emissions from the diesel-fired engines is as follows:

(a) GHG emissions from EUs 39– 44 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(b) Limit operation of the diesel-fired engines EUs 39 – 44 to no more than 500 hours per 12-month rolling period per engine; and

(c) GHG emissions from EUs 39 – 44 shall not exceed 163.6 lb/MMBtu averaged over a 3-hour period.

6.0 LARGE UTILITY HEATERS
GTP will have three building heat medium heaters (EUs 31 – 33). These heaters are natural gas-fired process heaters that will supply heat to buildings and other miscellaneous users, such as tank heaters. Each of the large utility heaters is rated at approximately 275 MMBtu/hr, for a total

of 825 MMBtu/hr. The large utility heaters will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

6.1 NOx

Possible NOx emission control technologies for the large utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.310: Natural Gas-Fired Utility and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr). The search results are summarized in Table 6-1.

Table 6-1: NOx Controls for Large Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	23	0.0032 - 0.20
Low-NOx Burners	24	0.011 - 0.25
No Control Specified	1	0.0125

Step 1 – Identify NOx Control Technologies for Large Utility Heaters

From research, the Department identified the following technologies as available for NOx control of gas-fired boilers and heaters rated at greater than 250 MMBtu/hr:

(a) Selective Catalytic Reduction (SCR)
The theory of SCR was discussed in detail in the NOx BACT Section 3.1 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that SCR is a common NOx control device for gas-fired boilers rated at greater than 250 MMBtu/hr. Therefore, the Department considers SCR to be a technically feasible control technology for the large utility heaters.

(b) Low-NOx Burners (LNB)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. The Department considers LNBs a technically feasible control technology for the large utility heaters.

(c) Ultra-Low NOx Burners
Ultra-low NOx burners operate on the same principle as LNB described above, but have advanced designs for achieving higher NOx destruction efficiencies. Designs that promote superior NOx destruction efficiencies often have a higher investment cost than typical LNBs. Some manufacturers of smaller heaters/boilers do not offer ultra-low NOx burners because the incremental emissions reduction is not cost effective as compared to standard LNBs. However, the Department's search of the RBLC database found several heaters/boilers greater than 250 MMBtu/hr using ultra-low NOx burners to control NOx

emissions. Hence, the Department considers the use of ultra-low NOx burners a technically feasible control technology for the large utility heaters.

(d) Flue Gas Recirculation (FGR)
FGR involves recycling a portion of the combustion gases from the stack to the boiler combustion air intake. The combustion products are low in oxygen, and when mixed with the combustion air, lower the overall excess oxygen concentration. This process acts as a heat sink to lower the peak flame temperature as well as the residence time at peak flame temperature. These effects work together to limit thermal NOx formation. The typical NOx removal efficiency using FGR is 20-25%. The Department considers FGR to be a technically feasible control technology for the large utility heaters.

(e) Good Combustion Practices (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are used to control NOx emissions for gas-fired boilers rated at greater than 250 MMBtu/hr. Therefore, the Department considers GCP and clean fuel to be a technically feasible control technology for the large utility heaters.

Step 2 – Eliminate Technically Infeasible NOx Control Options for Large Utility Heaters
All control technologies identified are technically feasible for gas-fired boilers and heaters rated at greater than 250 MMBtu/hr.

Step 3 – Rank Remaining NOx Control Options for Large Utility Heaters
The following control technologies have been identified and ranked for control of NOx from the large utility heaters:

(a) SCR (70% - 90% Control)
(b) Ultra-Low NOx Burner (80% Control)
(c) Low NOx Burner (60% Control)
(d) Flue Gas Recirculation (20% - 25% Control)
(e) Good Combustion Practices (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for large utility heaters. No unusual energy impacts were identified with the addition of SCR to the heaters. Environmental impacts include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system. Neither the ammonia slip nor the waste disposal of the catalyst would preclude the use of SCR as a potential NOx control device.

RBLC Review
A review of similar units in the RBLC indicates that SCR and low NOx / ultra-low NOx burners are the principle NOx control technologies installed on boilers and heaters rated at greater than 250 MMBtu/hr.

Applicant Proposal

AGDC stated that LNBs are already a part of the base model proposed for the large utility heaters at the GTP and provided an economic analysis of the top most effective control technology (SCR) to demonstrate that this control is not economically feasible for the EUs 31 – 33. A summary of the analysis for the large utility heaters is shown in Table 6-2.

Table 6-2: AGDC Economic Analysis for Technically Feasible NOx Controls (EUs 31 – 33)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	7.4	36.0.	$3,891,719	$672,628	$18,707
Capital Recovery Factor = 0.858 (7% interest rate for a 25 year equipment life)					

AGDC contends that the economic analysis indicates the level of NOx reduction from SCR does not justify the use of SCR for the large gas-fired heaters based on the excessive cost per ton of NOx removed per year.

AGDC proposes the following as BACT for NOx emissions from the large gas-fired heaters:

(a) NOx emissions from the operation of the large gas-fired heaters EUs 31 – 33 will be controlled with the use of LNB combustors; and

(b) NOx emissions from EUs 31 – 33 will not exceed 0.036 lb/MMBtu.

Department Evaluation of BACT for NOx Emissions from Large Gas-Fired Heaters

The Department revised the cost analysis to reflect the current bank prime interest rate of 3.25%. The Department included the same assumption used by AGDC that DLN is an inherent design feature of new gas-fired heaters and is therefore considered baseline for determining cost effectiveness. The Department did not modify the other assumptions used by AGDC in the cost analysis, including an 83% NOx control which reduced the NOx concentration from 0.036 lb/MMBtu to 0.0061 lb/MMBtu, an unrestricted potential to emit of 43.4 tpy, an aqueous ammonia cost of $5.67/gallon delivered to Prudhoe Bay (price quote from Brenntag), and the 0.16 $/kWh for electricity cost (average cost of electricity delivered to industrial customers in Alaska). A summary of the analyses for the large utility heaters is shown in Table 6-3.

Table 6-3: Department Economic Analysis for Technically Feasible NOx Controls (EUs 31–33)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	7.4	36.0.	$3,891,719	$568,895	$15,822
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the use of LNB as BACT for the large gas-fired utility heaters at the Gas Treatment Plant.

Step 5 – Selection of NOx BACT for Large Utility Heaters
The Department's finding is that BACT for NOx emissions from the gas-fired utility heaters rated at greater than 250 MMBtu/hr is as follows:

(a) NOx emissions from EUs 31 – 33 shall be controlled by operating and maintaining LNB and good combustion practices at all times the units are in operation;

(b) NOx emissions from EUs 31 – 33 shall not exceed 0.036 lb/MMBtu averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

6.2 CO
Possible CO emission control technologies for the large utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.310: Natural Gas-Fired Utility and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr). The search results are summarized in Table 6-4.

Table 6-4. CO Control for Large Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Oxidation Catalyst	1	0.0013
Good Combustion Practices	33	0.0013 - 0.47
No Control Specified	7	0.015 – 0.47

Step 1 – Identify CO Control Technologies for Large Utility Heaters
From research, the Department identified the following technologies as available for CO control of gas-fired boilers and heaters rated at greater than 250 MMBtu/hr:

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that oxidation catalysts have been used as a CO control device for gas-fired boilers rated at greater than 250 MMBtu/hr. Therefore, the Department considers oxidation catalysts to be a technically feasible control technology for the large utility heaters.

(b) Good Combustion Practices (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are used to control CO emissions for gas-fired boilers rated at greater than 250 MMBtu/hr. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for the large utility heaters.

Step 2 – Eliminate Technically Infeasible CO Control Options for Large Utility Heaters
All control technologies identified are technically feasible for gas-fired boilers and heaters rated at greater than 250 MMBtu/hr.

Step 3 – Rank Remaining CO Control Options for Large Utility Heaters
The following control technologies have been identified and ranked for control of CO from the large utility heaters:

(a) Oxidation Catalyst (90% Control)
(b) Good Combustion Practices and Clean Fuels (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst will reduce CO emissions from EUs 31 – 33 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Heater efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the principle CO control technologies used on boilers and heaters rated at greater than 250 MMBtu/hr. However, an oxidation catalyst would provide the best control for the large utility heaters and there were two facilities identified in the RBLC database that are using oxidation catalysts to control CO emissions from heaters and boilers rated greater than 250 MMBtu/hr.

Applicant Proposal
AGDC provided an economic analysis of the installation of oxidation catalysts on the large utility heaters which demonstrated that the use of this control is economically feasible on these units. However, AGDC stated that no examples of CO catalysts controls in the RBLC were found for the same size heater and that it is considered unlikely that CO controls would be imposed given this past precedent. A summary of the analysis for the large utility heaters is shown in Table 6-5.

Table 6-5: AGDC Economic Analysis for Technically Feasible CO Controls (EUs 31 – 33)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	7.3	29.1	$430,358	$135,898	$4,666
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

AGDC contends that although the cost per ton of CO removal using an oxidation catalyst is reasonable, the fact that no examples of an oxidation catalyst control in the RBLC were found for the same size heater make it unreasonable that this technology be imposed.

AGDC proposes the following as BACT for CO emissions from the large gas-fired heaters:

(a) CO emissions from the operation of the large gas-fired heaters EUs 31 – 33 will be controlled through good combustion practices and clean fuel; and

(b) CO emissions from EUs 31 – 33 will not exceed 0.037 lb/MMBtu.

Department Evaluation of BACT for CO Emissions from Large Gas-Fired Heaters

The Department revised the cost analysis to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, and revised the freight cost to 10% of the purchased equipment costs. A summary of the analyses for the large utility heaters is shown in Table 6-6.

Table 6-6: Department Economic Analysis for Technically Feasible CO Controls (EUs 31–33)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	9.3	33.9	$318,365	$88,941	$2,622
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of combined CO and VOC reduction justifies the use of an oxidation catalyst as BACT for the large gas-fired utility heaters at the Gas Treatment Plant. The Department identified one facility in the RBLC database (RBLC ID No. IA-0106) that has a gas-fired boiler/heater rated at greater than 250 MMBtu/hr with an oxidation catalyst installed for CO emissions control.

Step 5 – Selection of CO BACT for Large Utility Heaters
The Department's finding is that BACT for CO emissions from the gas-fired utility heaters rated at greater than 250 MMBtu/hr is as follows:

(a) CO emissions from EUs 31 – 33 shall be controlled by operating and maintaining an oxidation catalyst and good combustion practices at all times the units are in operation;

(b) CO emissions from EUs 31 – 33 shall not exceed 0.007 lb/MMBtu; and

(c) Initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

6.3 Particulates

Possible particulate emission control technologies for the large utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.310: Natural Gas-Fired Utility and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr). The search results are summarized in Table 6-7.

Table 6-7: Particulate Controls for Large Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
GCP & Clean Fuels	46	0.001 - 0.010
Baghouse	0	N/A
Wet Scrubber	0	N/A
No Control Specified	8	0.0019 - 0.0076

Step 1 – Identify Particulate Control Technologies for Large Utility Heaters
From research, the Department identified the following technologies as available for particulate control of gas-fired boilers and heaters rated at greater than 250 MMBtu/hr:

(a) Baghouse
Baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the "dirty" to the "clean" side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow operation within a range of design pressure drop. Baghouses are characterized by the type of cleaning cycle - mechanical-shaker, pulse-jet, and reverse-air. Fabric filter systems have control efficiencies of 95% to 99.9% [13] and are generally specified to meet a discharge concentration of filterable particulate (e.g., 0.01 grains per dry standard cubic feet). The only entry for baghouses in the RBLC was for furnaces at an iron ore concentrate pelletizing facility in Indiana. This process involves iron ore pellets being exposed to high temperatures in a furnace in order to harden the pellets, which emits hazardous air pollutants (HAPs). At the GTP, EUs 31 – 33 will be used for providing space heating and will burn natural gas, a much cleaner process. Due to the fact that the only large gas-fired boilers/heaters in the RBLC with baghouses used to control particulates are actually installed because of the iron ore pelletizing process, the Department does not consider a baghouse a technically feasible control technology for the large utility heaters located at the GTP.

(b) Wet Scrubber
Wet Scrubbers use a scrubbing solution to remove particulate matter from exhaust streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid flows in the opposite direction as the gas flow. The only entry for wet scrubbers in the RBLC was for furnaces at an iron ore concentrate pelletizing facility in Texas. This process involves iron ore pellets being exposed to high temperatures in a furnace in order to harden the pellets, which emits HAPs. At the GTP, EUs 31 – 33 will be used for providing space heating and will burn natural gas, a much cleaner process. Due to the fact that the only large gas-fired boilers/heaters in the RBLC with wet scrubbers used to control particulates are actually installed because of the iron ore pelletizing process, the Department does not consider the use of wet scrubbers a technically feasible control technology for the large utility heaters located at the GTP.

(c) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. EUs 31 – 33 are the only EUs that will supply building heat for the GTP. Therefore, it is not appropriate to limit the operation of these units. The Department does not consider the use of limited operation a technically feasible control technology for the large utility heaters.

[13] https://www3.epa.gov/ttn/catc/dir1/ff-shaker.pdf
https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf
https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf

(d) Good Combustion Practices and Clean Fuels
The theory of GCP and clean fuels was discussed in detail in the CO BACT section 4.2, for the gas-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process and burning clean fuels will result in a reduction of particulate emissions. The Department considers GCP and clean fuels a technically feasible control technology for the large utility heaters.

(e) Flue Gas Recirculation (FGR)
The theory behind FGR was discussed in detail in the NOx BACT Section 6.1 and will not be repeated here. The Department's research did not identify facilities using FGR to control particulate emissions for large gas-fired boilers/heaters. Therefore, the Department considers this technology technically infeasible for the large utility heaters at GTP.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for Large Utility Heaters
As explained in Step 1, FGR, baghouses, wet scrubbers, and limited operation are not feasible technologies to control particulate emissions from the large utility heaters.

Step 3 – Rank Remaining Particulate Control Options for Large Utility Heaters
AGDC has accepted the only technically feasible control options for the large utility heaters EUs 31 – 33. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Use of clean low-sulfur fuel and good combustion practices are the most effective controls for particulates from natural gas fired boilers and heaters rated at greater than 250 MMBtu/hr. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that use of clean fuels and good combustion practices are the principle control methods for particulates from boilers firing natural gas rated at greater than 250 MMBtu/hr.

Applicant Proposal
AGDC proposed to use clean fuel and good combustion practices for the large utility heaters EUs 31 – 33 as BACT for reducing particulate emissions. Particulate emissions from EUs 31 – 33 will not exceed 0.0079 lb/MMBtu.

Step 5 – Selection of Particulate BACT for Large Utility Heaters
The Department's finding is that BACT for particulate emissions from the gas-fired utility heaters rated at greater than 250 MMBtu/hr is as follows:

(a) Particulate emissions from EUs 31 – 33 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) Particulate emissions from EUs 31 – 33 shall not exceed 0.0079 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1.4-2, particulate (total) emissions rate for natural gas combustion in external combustion sources); and

(c) Initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

6.4 SO_2

Possible SO_2 emission control technologies for the large utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.310: Natural Gas-Fired Utility and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr). The search results are summarized in Table 6-8.

Table 6-8: SO_2 Control for Large Natural Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits
GCP & Clean Fuel	13	0.0006 – 0.002 lb/MMBtu 0.09 – 1,286 lb/hr
No Control	8	0.0006 – 0.003 lb/MMBtu 0.02 – 64 lb/hr

Step 1 – Identify SO_2 Control Technologies for Large Utility Heaters

From research, the Department identified the following technologies as available for SO_2 control of gas-fired boilers and heaters rated at greater than 250 MMBtu/hr:

(a) Good Combustion Practices (GCP) and Clean Fuels
As discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3, GCP and clean fuels is a common technique for controlling SO_2 emissions. SO_2 emissions in the exhaust of liquid or gas-fired boilers and heaters are directly related to the levels of sulfur in fuel. As such, fuel specifications are the primary method of SO_2 emissions control and are a feasible control technology for the large utility heaters.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for Large Utility Heaters

All control technologies identified are technically feasible for gas-fired boilers and heaters rated at greater than 250 MMBtu/hr.

Step 3 – Rank Remaining SO_2 Control Options for Large Utility Heaters

AGDC has accepted the only technically feasible control technology for the large gas-fired utility heaters. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

According to the RBLC, clean fuels and good combustion practices are the applicable controls for SO_2 emissions for EUs 31 – 33. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only SO_2 emission control technologies installed on gas-fired heaters and boilers rated at greater than 250 MMBtu/hr.

Applicant Proposal
AGDC proposed to use clean fuels and good combustion practices for the large utility heaters EUs 31 – 33 as BACT for reducing SO_2 emissions. AGDC will utilize natural gas in the large utility heaters EUs 31 – 33 with a total sulfur content not to exceed 96 ppmv during the initial phases of operation prior to the natural gas treatment trains becoming operational. Upon completion of the three natural gas treatment trains the total sulfur content of the fuel will not exceed 16 ppmv.

Step 5 – Selection of SO_2 BACT for Large Utility Heaters
The Department's finding is that BACT for SO_2 emissions from the gas-fired utility heaters rated at greater than 250 MMBtu/hr is as follows:

(a) SO_2 emissions from EUs 31 – 33 shall be minimized by maintaining good combustion practices and burning natural gas at all times the units are in operation;
(b) Prior to the completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 31 – 33 shall not to exceed 96 ppmv (equivalent to SO_2 emissions of 4.2 lb/hr for each heater);
(c) Upon completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 31 – 33 shall not to exceed 16 ppmv (equivalent to SO_2 emissions of 0.70 lb/hr for each heater); and
(d) Compliance with the proposed limits will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

6.5 VOC
Possible VOC emission control technologies for the large utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.310: Natural Gas-Fired Utility and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr). The search results are summarized in Table 6-9.

Table 6-9: VOC Control for Large Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Oxidation Catalyst	0	N/A
GCP & Clean Fuel	17	0.0014 – 0.054
No Control Specified	5	0.0053 – 0.0055

Step 1 – Identify VOC Control Technologies for Large Utility Heaters
From research, the Department identified the following technologies as available for VOC control of gas-fired boilers and heaters rated at greater than 250 MMBtu/hr:

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that oxidation catalysts have been used as a VOC control device for gas-fired boilers rated at greater than 250

MMBtu/hr. Therefore, the Department considers oxidation catalysts to be a technically feasible control technology for the large utility heaters.

(b) Good Combustion Practices (GCPs) and clean fuel
The theory of GCPs and clean fuel was discussed in detail in CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are the primary technique used to control VOC emissions for gas-fired boilers rated at greater than 250 MMBtu/hr. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for the large utility heaters.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Large Utility Heaters
Both control technologies identified are technically feasible for gas-fired boilers and heaters rated at greater than 250 MMBtu/hr.

Step 3 – Rank Remaining VOC Control Options for Large Utility Heaters
The following control technologies have been identified and ranked for control of VOC from the boilers and heaters:

(a) Oxidation Catalyst (90% Control)
(b) Good Combustion Practices (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst would provide the best VOC control for gas-fired heaters and boilers rated at greater than 250 MMBtu/hr. Since these are not add-on controls, there are no additional environmental impacts. The only BACT determination in the RBLC using an oxidation catalyst is for a biomass/distillate oil/natural gas fired utility heater, which is not a similar unit to any of EUs 31 – 33, which only fire natural gas. However, an oxidation catalyst emissions control system has already been selected as BACT for CO emissions from EUs 31 – 33 and will be effective at reducing VOC emissions.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principle control method for VOC from gas-fired heaters and boilers rated at greater than 250 MMBtu/hr.

Applicant Proposal
AGDC proposed to use good combustion practices and clean fuel for the large utility heaters EUs 31 - 33 as BACT for reducing VOC emissions. VOC emissions from EUs 31 – 33 will not exceed 0.0057 lb/MMBtu.

Department Evaluation of BACT for VOC Emissions from Large Gas-Fired Heaters
The Department revised the cost analysis to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan, adjusted the interest rate to the current bank prime interest rate of 3.25%, and revised the freight cost to 10% of the purchased equipment costs. A summary of the analyses for the large utility heaters is shown in Table 6-10.

Table 6-10: Department Economic Analysis for Technically Feasible VOC Controls (EUs 31–33)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	9.3	33.9	$318,365	$88,941	$2,622
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of combined CO and VOC reduction justifies the use of an oxidation catalyst as BACT for the large gas-fired utility heaters at the Gas Treatment Plant. The Department identified one facility in the RBLC database (RBLC ID No. IA-0106) that has a gas-fired boiler/heater rated at greater than 250 MMBtu/hr with an oxidation catalyst installed for CO emissions control.

Step 5 – Selection of VOC BACT for Large Utility Heaters
The Department's finding is that BACT for VOC emissions from the large gas-fired utility heaters rated at greater than 250 MMBtu/hr is as follows:

(a) VOC emissions from EUs 31 – 33 shall be controlled by operating and maintaining an oxidation catalyst and good combustion practices at all times the units are in operation;

(b) VOC emissions from EUs 31 – 33 shall not exceed 0.0029 lb/MMBtu averaged over a 3-hour period (AP-42, Table 1.4-2, VOC emission rate for natural gas combustion in external combustion sources with 50% VOC removal[14] from oxidation catalyst); and

(c) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

6.6 GHG

Possible GHG emission control technologies for the large utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.310: Natural Gas-Fired Utility and Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr). The search results are summarized in Table 6-10.

Table 6-10: GHG Control for Large Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits tpy
GCP & Clean Fuel	24	4,339 – 826,600 tpy 117 lb/MMBtu
No Control	12	113,552 – 700,000 tpy 117.1 lb/MMBtu

[14] The 50% VOC removal rate from the oxidation catalyst takes into account that BACT emission rates must be achievable at all times and that the AP-42 Emission Factor Rating for external combustion sources burning natural gas is a C.

CO_2 and N_2O emissions are produced during natural gas combustion in gas-fired heaters. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, regardless of the firing configuration. CH_4 is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas.

Step 1 – Identify GHG Control Technologies for Large Utility Heaters
From research, the Department identified the following technologies as available for VOC control of gas-fired boilers and heaters rated at greater than 250 MMBtu/hr:

(a) Carbon Capture and Sequestration
CCS was discussed in detail in the GHG BACT Section 4.6 for simple cycle turbines, and will not be repeated here. The Department's research did not identify CCS as a control technology used to control GHG emissions from heaters or any other emission unit type installed at any facility in the RBLC database. Additionally, the Department performed an economic analysis for CCS on the turbines EUs 1 – 30 at the GTP and found the costs to economically infeasible. Therefore, the Department considers this technology to be both technologically and economically infeasible for controlling GHG emissions from the large utility heaters.

(b) Good Combustion Practices and Clean Fuels
Discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of liquid or gas-fired boilers and heaters are directly related to the carbon content in the fuel. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel, and is considered a feasible control technology for the large utility heaters.

Step 2 – Eliminate Technically Infeasible GHG Control Options for Large Utility Heaters
As explained in Step 1, CCS is not considered a technically feasible technology to control GHG emissions from gas-fired boilers and heaters rated at greater than 250 MMBtu/hr.

Step 3 – Rank Remaining GHG Control Options for Large Utility Heaters
AGDC has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, clean fuels and good combustion practices are the applicable controls for GHG emissions for EUs 31 – 33. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the principle control method for GHG from gas-fired boilers and heaters rated at greater than 250 MMBtu/hr.

Applicant Proposal
AGDC proposed to use good combustion practices and clean fuels for the large utility heaters EUs 31 – 33 as BACT for reducing GHG emissions. GHG emissions from EUs 31 – 33 will not

exceed 117.1 lb/MMBtu, which is the CO_2e emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Step 5 – Selection of GHG BACT for Large Utility Heaters
The Department's finding is that BACT for GHG emissions from the gas-fired boilers and heaters rated at greater than 250 MMBtu/hr:

(a) GHG emissions from EUs 31 – 33 shall be controlled by maintaining good combustion practices at all times the units are in operation; and

(b) GHG emissions from EUs 31 – 33 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

7.0 SMALL UTILITY HEATERS

GTP will use two buyback gas bath heaters (EUs 34 – 35) and three operations camp heaters (EUs 36 – 38). The operations camps and the buyback gas bath heaters, are natural gas-fired process heaters that would supply space heating to the camp and condition raw inlet gas for use as temporary fuel when treated gas is not available. The three operations camp heaters each have a design duty of 32 MMBtu/hr. There would be two buyback gas bath heaters, one with a design duty of 25 MMBtu/hr and the other rated at 21 MMBtu/hr. The buyback gas bath heaters are anticipated to operate up to 500 hours/year each unit, whereas the Operations Camp heaters are expected to operate 8,760 hours/year. The small utility heaters will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

7.1 NOx

Possible NOx emission control technologies for the utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310: Natural Gas-Fired Boilers/Furnaces (<100 MMBtu/hr). The search results are summarized in Table 7-1.

Table 7-1: NOx Controls for Small Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	2	0.009
Low NOx Burners	64	0.0011 – 0.07
Good Combustion Practices	5	0.035 – 0.10
No Control Specified	10	0.013 – 0.10

RBLC Review
A review of similar units in the RBLC indicates good combustion practices, low NOx burners, selective catalytic reduction, and selective non-catalytic reduction are the principle NOx control technologies installed on gas-fired boilers. The lowest emission rate listed in the RBLC is 0.006 lb/MMBtu.

Step 1 – Identify NOx Control Technologies for Small Utility Heaters
From research, the Department identified the following technologies as available for NOx control of gas-fired boilers and heaters rated at less than 100 MMBtu/hr:

(a) Selective Catalytic Reduction (SCR)
The theory of SCR was discussed in detail in the NOx BACT section 3.1 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that SCR is used as a NOx control device for gas-fired boilers rated at less than 100 MMBtu/hr. Therefore, the Department considers SCR to be a technically feasible control technology for the small utility heaters.

(b) Low-NOx Burners (LNB)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. The Department considers LNBs a technically feasible control technology for the small utility heaters.

(c) Ultra-Low NOx Burners
Ultra-low NOx burners operate on the same principle as LNB described above, but have advanced designs for achieving higher NOx destruction efficiencies. Designs that promote superior NOx destruction efficiencies often have a higher investment cost than typical LNBs. Some manufacturers of smaller heaters/boilers do not offer ultra-low NOx burners because the incremental emissions reduction is not cost effective as compared to standard LNBs. However, the Department's search of the RBLC database found several heaters/boilers less than 100 MMBtu/hr using ultra-low NOx burners to control NOx emissions. Hence, the Department considers the use of ultra-low NOx burners a technically feasible control technology for the small utility heaters.

(d) Flue Gas Recirculation (FGR)
FGR involves recycling a portion of the combustion gases from the stack to the boiler combustion air intake. The combustion products are low in oxygen, and when mixed with the combustion air, lower the overall excess oxygen concentration. This process acts as a heat sink to lower the peak flame temperature as well as the residence time at peak flame temperature. These effects work together to limit thermal NOx formation. The typical NOx removal efficiency using FGR is 20-25%. The Department considers FGR to be a technically feasible control technology for the small utility heaters.

(e) Good Combustion Practices (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are used to control NOx emissions for gas-fired boilers rated at less than 100 MMBtu/hr. Therefore, the Department considers SCR to be a technically feasible control technology for the small utility heaters.

Step 2 – Eliminate Technically Infeasible NOx Control Options for Small Utility Heaters

All control technologies identified are technically feasible for gas-fired boilers and heaters rated at less than 100 MMBtu/hr.

Step 3 – Rank Remaining NOx Control Options for Small Utility Heaters
The following control technologies have been identified and ranked for control of NOx from the small utility heaters:

(a) SCR (70% - 90% Control)
(b) Ultra-Low NOx Burner (80% Control)
(c) Low NOx Burner (60% Control)
(d) Flue Gas Recirculation (20% - 25% Control)
(e) Good Combustion Practices (<40% Control)

Step 4 – Evaluate the Most Effective Controls
RBLC Review
SCR is the most effective NOx control for small utility heaters. No unusual energy impacts were identified with the addition of SCR to the heaters. Environmental impacts include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system. Neither the ammonia slip nor the waste disposal of the catalyst would preclude the use of SCR as a potential NOx control device.

A review of similar units in the RBLC indicates that low NOx / ultra-low NOx burners are the principle NOx control technologies installed on boilers and heaters rated at less than 100 MMBtu/hr.

Applicant Proposal
AGDC provided an economic analysis of the most effective control technology (SCR) to demonstrate that this control is not economically feasible for the small utility heaters. A summary of AGDC's analysis for the buyback gas bath heater EUs 34 and 35 are shown in Tables 7-2, and 7-3 respectively, and the analysis for the camp heaters EUs 36 through 38 are shown in Table 7-4. Note that the cost analysis in Table 7-4 is on a per heater basis.

Table 7-2: AGDC Economic Analysis for Technically Feasible NOx Controls (EU 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	0.039	0.19	$826,216	$76,769	$405,882
Capital Recovery Factor = 0.0858 (7% interest rate for a 25 year equipment life)					

Table 7-3: AGDC Economic Analysis for Technically Feasible NOx Controls (EU 35)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	0.029	0.14	$686,477	$63,673	$447,679
Capital Recovery Factor = 0.0858 (7% interest rate for a 25 year equipment life)					

Table 7-4: AGDC Economic Analysis for Technically Feasible NOx Controls (EUs 36-38)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	0.85	4.17	$959,490	$125,115	$29,997
Capital Recovery Factor = 0.0858 (7% interest rate for a 25 year equipment life)					

AGDC contends that the economic analysis indicates the level of NOx reduction from SCR does not justify the use of SCR for the small gas-fired heaters based on the excessive cost per ton of NOx removed per year.

AGDC proposes the following as BACT for NOx emissions from the small gas-fired heaters:

(a) NOx emissions from the operation of the small gas-fired heaters EUs 34 – 38 will be controlled with the use of DLN combustors;

(b) NOx emissions from the operation of EUs 34 and 35 will be controlled through limited operation of 500 hours per 12-month rolling period per boiler; and

(c) NOx emissions from EUs 34 – 38 will not exceed 0.036 lb/MMBtu.

Department Evaluation of BACT for NOx Emissions from Small Gas-Fired Heaters

The Department revised the cost analyses to reflect the current bank prime interest rate of 3.25% and a higher rated capacity for EU 35. The Department included the same assumption used by AGDC that DLN is an inherent design feature of new gas-fired heaters and is therefore considered baseline for determining cost effectiveness. The Department did not modify the other assumptions used by AGDC in the cost analyses, including an 83% NOx control which reduced the NOx concentrations in the heaters from 0.036 lb/MMBtu to 0.0061 lb/MMBtu, an aqueous ammonia cost of $5.67/gallon delivered to Prudhoe Bay (price quote from Brenntag), and the 0.16 $/kWh for electricity cost (average cost of electricity delivered to industrial customers in Alaska). A summary of the analyses for the buyback gas bath heater EUs 34 and 35 are shown in Tables 7-5, and 7-6 respectively, and the analysis for the camp heaters EUs 36 through 38 are shown in Table 7-7. Note that the cost analysis in Table 7-7 is on a per heater basis.

Table 7-5: Department Economic Analysis for Technically Feasible NOx Controls (EU 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	0.039	0.19	$826,216	$54,682	$356,758
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 7-6: Department Economic Analysis for Technically Feasible NOx Controls (EU 35)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	0.033	0.16	$729,806	$48,227	$308,608
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 7-7: Department Economic Analysis for Technically Feasible NOx Controls (EUs 36-38)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR with DLN	0.85	4.17	$959,490	$99,470	$23,848
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction does not justify the use of SCR as BACT for the small gas-fired utility heaters at the Gas Treatment Plant.

Step 5 – Selection of NOx BACT for Small Utility Heaters
The Department's finding is that BACT for NOx emissions from the gas-fired utility heaters rated at less than 100 MMBtu/hr is as follows:

(a) NOx emissions from EUs 34 – 38 shall be controlled by operating and maintaining LNBs at all times the units are in operation;

(b) Limit operation of EUs 34 and 35 to no more than 500 hours per 12-month rolling period per boiler;

(c) NOx emissions from EUs 34 – 38 shall not exceed 0.036 lb/MMBtu averaged over a 3-hour period; and

(d) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

7.2 CO

Possible CO emission control technologies for the small utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310: Natural Gas-Fired Boilers/Furnaces (<100 MMBtu/hr). The search results are summarized in Table 7-8.

Table 7-8: CO Controls for Small Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
GCP and Clean Fuels	67	0.0075 – 0.84
No Control Specified	10	0.037 – 0.11

Step 1 – Identify CO Control Technologies for Small Utility Heaters
From research, the Department identified the following technologies as available for CO control of gas-fired boilers and heaters rated at less than 100 MMBtu/hr:

(a) Oxidation Catalyst
The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a CO control device for gas-fired boilers rated at less than 100 MMBtu/hr. Therefore, the Department does not consider oxidation catalysts to be a technically feasible control technology for the small utility heaters.

(b) Good Combustion Practices (GCP) and Clean Fuel
The theory of GCPs and clean fuel was discussed in detail in CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are used to control CO emissions for gas-fired boilers rated at less than 100 MMBtu/hr. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for the small utility heaters.

Step 2 – Eliminate Technically Infeasible CO Control Options for Small Utility Heaters
As explained in Step 1, oxidation catalysts are not technically feasible for gas-fired boilers and heaters rated at less than 100 MMBtu/hr.

Step 3 – Rank Remaining CO Control Options for Small Utility Heaters
The following control technologies have been identified and ranked for control of CO from the small utility heaters:

(a) Good Combustion Practices and Clean Fuels (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices and clean fuels are the applicable controls for CO emissions for EUs 34 – 38. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only CO emission control technologies installed on gas-fired heaters and boilers rated at less than 100 MMBtu/hr.

Applicant Proposal
AGDC provided an economic analysis of the top most effective control technology (oxidation catalyst) to demonstrate that this control is not economically feasible for the buyback gas bath heaters EUs 34 and 35. Additionally, AGDC stated that although the cost removal per ton for the operations camp heaters EUs 36 through 38 may be considered economically feasible, the fact that no gas-fired heaters rated at less than 100 MMBtu/hr were found using an oxidation catalyst in the RBLC database indicates that this control technology should be eliminated from consideration. A summary of AGDC's analysis for the buyback gas bath heater EUs 34 and 35 are shown in Tables 7-9, and 7-10 respectively, and the analysis for the camp heaters EUs 36 through 38 are shown in Table 7-11. Note that the cost analysis in Table 7-11 is on a per heater basis.

Table 7-9: AGDC Economic Analysis for Technically Feasible CO Controls (EU 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.05	0.47	$47,818	$15,100	$32,381
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Table 7-10: AGDC Economic Analysis for Technically Feasible CO Controls (EU 35)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.04	0.39	$40,167	$12,684	$32,381
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Table 7-11: AGDC Economic Analysis for Technically Feasible CO Controls (EUs 36-38)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	1.04	10.46	$61,206	$19,328	$1,848
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

AGDC contends that the economic analysis indicates the level of CO reduction from an oxidation catalyst does not justify the use of this control for the buyback bath gas heaters EUs 34 and 35 based on the excessive cost per ton of CO removed per year. AGDC also contends that although the cost per ton of CO removal using an oxidation catalyst is reasonable for the operations camp heaters EUs 36 through 38, the fact that no examples of an oxidation catalyst control in the RBLC were found for the same size heater make it unreasonable that this technology be imposed.

AGDC proposes the following as BACT for CO emissions from the small gas-fired heaters:

(a) CO emissions from the operation of the small gas-fired heaters EUs 34 – 38 will be controlled by good combustion practices and clean fuels;

(b) CO emissions from the operation of EUs 34 and 35 will be controlled through limited operation of 500 hours per 12-month rolling period per boiler; and

(c) CO emissions from EUs 34 – 38 will not exceed 0.087 lb/MMBtu.

Department Evaluation of BACT for CO Emissions from Small Gas-Fired Heaters

The Department revised the cost analyses to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analyses for the buyback gas bath heater EUs 34 and 35 are shown in Tables 7-12, and 7-13 respectively, and the analysis for the camp heaters EUs 36 through 38 are shown in Table 7-14. Note that the cost analysis in Table 7-14 is on a per heater basis.

Table 7-12: Department Economic Analysis for Technically Feasible CO Controls (EU 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.06	0.52	$47,818	$11,115	$21,261
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 7-13: Department Economic Analysis for Technically Feasible CO Controls (EU 35)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.05	0.44	$40,167	$9,336	$21,269
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 7-14: Department Economic Analysis for Technically Feasible CO Controls (EUs 36-38)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	1.27	11.71	$61,206	$14,227	$1,214
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EUs 34 and 35. While the economic analysis indicates that an oxidation catalyst would be cost effective for EUs 36 through 38, there were no instances of gas-fired heaters rated at less than 100 MMBtu/hr in the RBLC, and is therefore considered a technically infeasible control option.

Step 5 – Selection of CO BACT for Small Utility Heaters

The Department's finding is that BACT for CO emissions from the gas-fired utility heaters rated at less than 100 MMBtu/hr is as follows:

(a) CO emissions from EUs 34 through 38 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(b) Limit operation of EUs 34 and 35 to no more than 500 hours per 12-month rolling period per boiler;

(c) CO emissions from EUs 34 through 38 shall not exceed 0.087 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1.4-1, CO emissions rate for natural gas combustion in external combustion sources; and

(d) For EUs 34 – 38, initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

7.3 Particulates

Possible particulate emission control technologies for the small utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310: Natural Gas-Fired Boilers/Furnaces (<100 MMBtu/hr). The search results are summarized in Table 7-15.

Table 7-15: Particulate Control for Small Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
GCP & Clean Fuels	102	0.0004 - 0.018
Limited Operation	1	0.0074
No Control Specified	20	0.005 - 0.008

Step 1 – Identify Particulate Control Technologies for Small Utility Heaters

From research, the Department identified the following technologies as available for particulate control of gas-fired boilers and heaters rated at less than 100 MMBtu/hr:

(a) Good Combustion Practices and Clean Fuels
The theory of GCP and clean fuels was discussed in detail in the CO BACT section 4.2, for the gas-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process and burning clean fuels will result in a reduction of particulate emissions. The Department considers GCP and clean fuels a technically feasible control technology for the small utility heaters.

(b) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The buyback gas bath heaters EUs 34 and 35 will be used to condition raw inlet gas for use as temporary fuel when treated gas is not available, with each heater limited to 500 hours of operation per year. The operations camps heaters EUs 36 through 38 will provide space heat at GTP's camps, and therefore cannot take limits to their amount operation in the arctic environment.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for Small Utility Heaters
As explained in Step 1, limited operation is not a feasible technology for the operations camps heaters EUs 36 – 38 to control particulate emissions.

Step 3 – Rank Remaining Particulate Control Options for Small Utility Heaters
AGDC has accepted the only technically feasible control options for the small utility heaters EUs 34 – 38. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Use of clean low-sulfur fuel and good combustion practices are the most effective controls for particulates from natural gas fired boilers and heaters rated at less than 100 MMBtu/hr. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that use of clean fuels and good combustion practices are the principle control methods for particulates from boilers firing natural gas rated at less than 1000 MMBtu/hr.

Applicant Proposal
AGDC proposed to use clean fuel and good combustion practices for the small utility heaters EUs 34 – 38 as BACT for reducing particulate emissions. Additionally, EUs 34 and 35 will be limited to 500 hours per 12-month rolling period per boiler. Particulate emissions from EUs 34 – 38 will not exceed 0.0079 lb/MMBtu.

Step 5 – Selection of Particulate BACT for Small Utility Heaters
The Department's finding is that BACT for particulate emissions from the gas-fired utility heaters rated at less than 100 MMBtu/hr is as follows:

(a) Particulate emissions from EUs 34 – 38 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) Limit operation of EUs 34 and 35 to no more than 500 hours per 12-month rolling period per boiler;

(c) Particulate emissions from EUs 34 – 38 shall not exceed 0.0079 lb/MMBtu averaged over a 3-hour period (AP-42 Table 1.4-2, particulate (total) emissions rate for natural gas combustion in external combustion sources); and

(d) Initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

7.4 SO_2
Possible SO_2 emission control technologies for the small utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310: Natural Gas-Fired Boilers/Furnaces (<100 MMBtu/hr). The search results are summarized in Table 7-16.

Table 7-16: SO_2 Control for Small Natural Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits[12] (Sulfur in Fuel)
GCP & Clean Fuel	10	0.6 – 5 gr/100 dscf 10.2 – 84.6 ppmv
No Control	1	2 gr/100 dscf 33.8 ppmv

Step 1 – Identify SO_2 Control Technologies for Small Utility Heaters
From research, the Department identified the following technologies as available for SO_2 control of gas-fired boilers and heaters rated at less than 100 MMBtu/hr:

(a) Good Combustion Practices (GCP) and Clean Fuels
As discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3, GCP and clean fuels is a common technique for controlling SO_2 emissions. SO_2 emissions in the exhaust of liquid or gas-fired boilers and heaters are directly related to the levels of sulfur in fuel. As such, fuel specifications are the primary method of SO_2 emissions control and are a feasible control technology for the utility heaters.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for Small Utility Heaters
All control technologies identified are technically feasible for gas-fired boilers and heaters rated at less than 100 MMBtu/hr.

Step 3 – Rank Remaining SO_2 Control Options for Small Utility Heaters
AGDC has accepted the only technically feasible control technology for the gas-fired utility heaters. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, clean fuels and good combustion practices are the applicable controls for SO_2 emissions for EUs 34 – 38. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the only SO_2 emission control technologies installed on gas-fired heaters and boilers rated at less than 100 MMBtu/hr.

Applicant Proposal
AGDC proposed to use clean fuels and good combustion practices for the small utility heaters EUs 34 – 38 as BACT for reducing SO_2 emissions. Additionally, EUs 34 and 35 will be limited to 500 hours per 12-month rolling period per boiler. AGDC will utilize only natural gas in the small utility heaters EUs 34 – 38 with a total sulfur content not to exceed 96 ppmv during the initial phases of operation prior to the natural gas treatment trains becoming operational. Upon completion of the three natural gas treatment trains the total sulfur content of the fuel will not exceed 16 ppmv.

Step 5 – Selection of SO_2 BACT for Small Utility Heaters

The Department's finding is that BACT for SO_2 emissions from the gas-fired utility heaters rated at less than 100 MMBtu/hr is as follows:

(a) SO_2 emissions from EUs 34 – 38 shall be minimized by maintaining good combustion practices and burning natural gas at all times the units are in operation;

(b) Prior to the completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 34 – 38 shall not to exceed 96 ppmv;

(c) Upon completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 34 – 38 shall not exceed 16 ppmv;

(d) Limit operation of EUs 34 and 35 to no more than 500 hours per 12-month rolling period per boiler; and

(e) Compliance with the proposed fuel sulfur content limits will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

7.5 VOC

Possible VOC emission control technologies for the utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310: Natural Gas-Fired Boilers/Furnaces (<100 MMBtu/hr). The search results are summarized in Table 7-17.

Table 7-17: VOC Control for Small Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion Practices	40	0.0014 – 0.02
No Control Specified	6	0.0050 – 0.0054

Step 1 – Identify VOC Control Technologies for Small Utility Heaters

From research, the Department identified the following technologies as available for VOC control of gas-fired boilers and heaters rated at less than 100 MMBtu/hr:

(a) Oxidation Catalyst

The theory of oxidation catalysts were discussed in detail in the CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database did not identify any oxidation catalysts used as a VOC control device for gas-fired boilers rated at less than 100 MMBtu/hr. Therefore, the Department does not consider oxidation catalysts to be a technically feasible control technology for the small utility heaters.

(b) Good Combustion Practices (GCPs) and clean fuel

The theory of GCPs and clean fuel was discussed in detail in CO BACT section 3.2 for the large combined cycle natural gas-fired combustion turbines and will not be repeated here. The Department's search of the RLBC database indicated that GCPs and clean fuel are the primary technique used to control VOC emissions for gas-fired boilers rated at less than 100 MMBtu/hr. Therefore, the Department considers GCPs and clean fuel to be a technically feasible control technology for the small utility heaters.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Small Utility Heaters

As explained in Step 1, oxidation catalysts are not technically feasible for gas-fired boilers and heaters rated at less than 100 MMBtu/hr.

Step 3 – Rank Remaining VOC Control Options for Small Utility Heaters
The following control technologies have been identified and ranked for control of VOC from the small boilers and heaters:

(a) Good Combustion Practices (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, good combustion practices and clean fuels are the applicable controls for VOC emissions for EUs 34 – 38. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principle control method for VOC from gas-fired heaters and boilers rated at less than 100 MMBtu/hr.

Applicant Proposal
AGDC proposed to use good combustion practices and clean fuel for the small utility heaters EUs 34 - 38 as BACT for reducing VOC emissions. Additionally, EUs 34 and 35 will be limited to 500 hours per 12-month rolling period per boiler. VOC emissions from EUs 34 – 38 will not exceed 0.0057 lb/MMBtu.

Department Evaluation of BACT for VOC Emissions from Small Gas-Fired Heaters
The Department revised the cost analyses to include the CO and VOC emissions removed into one cost calculation, to reflect the equipment life revised to a 25 year lifespan and adjusted the interest rate to the current bank prime interest rate of 3.25%. A summary of the analyses for the buyback gas bath heater EUs 34 and 35 are shown in Tables 7-18, and 7-19 respectively, and the analysis for the camp heaters EUs 36 through 38 are shown in Table 7-20. Note that the cost analysis in Table 7-20 is on a per heater basis.

Table 7-18: Department Economic Analysis for Technically Feasible CO Controls (EU 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.06	0.52	$47,818	$11,115	$21,261
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 7-19: Department Economic Analysis for Technically Feasible CO Controls (EU 35)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	0.05	0.44	$40,167	$9,336	$21,269
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 7-20: Department Economic Analysis for Technically Feasible CO Controls (EUs 36-38)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Oxidation Catalyst	1.27	11.71	$61,206	$14,227	$1,214
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EUs 34 and 35. While the economic analysis indicates that an oxidation catalyst would be cost effective for EUs 36 through 38, there were no instances of gas-fired heaters rated at less than 100 MMBtu/hr in the RBLC, and is therefore considered a technically infeasible control option.

Step 5 – Selection of VOC BACT for Small Utility Heaters

The Department's finding is that BACT for VOC emissions from the gas-fired utility heaters rated at less than 100 MMBtu/hr is as follows:

(a) VOC emissions from EUs 34 – 38 shall be controlled by maintaining good combustion practices at all times the units are in operation;

(b) Limit operation of EUs 34 and 35 to no more than 500 hours per 12-month rolling period per boiler;

(c) VOC emissions from EUs 34 – 38 shall not exceed 0.0057 lb/MMBtu averaged over a 3-hour period (AP-42, Table 1.4-2, VOC emission rate for natural gas combustion in external combustion sources); and

(d) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limit.

7.6 GHG

Possible GHG emission control technologies for the small utility heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.310: Natural Gas-Fired Boilers/Furnaces (<100 MMBtu/hr). The search results are summarized in Table 7-21.

Table 7-21: GHG Control for Small Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (tpy)
GCP & Clean Fuels	34	345 – 153,716 tpy 117.0 – 120.0 lb/MMBtu
Limited Operation	1	187 tpy
No Control	18	625 – 131,405 tpy 117.0 – 119.0 lb/MMBtu

CO_2 and N_2O emissions are produced during natural gas combustion in gas-fired heaters. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, regardless of the firing configuration. CH_4 is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas.

Step 1 – Identify GHG Control Technologies for Small Utility Heaters
From research, the Department identified the following technologies as available for VOC control of gas-fired boilers and heaters rated at less than 100 MMBtu/hr:

(a) Carbon Capture and Sequestration (CCS)
CCS was discussed in detail in the GHG BACT Section 4.6 for simple cycle turbines, and will not be repeated here. The Department's research did not identify CCS as a control technology used to control GHG emissions from heaters or any other emission unit type installed at any facility in the RBLC database. Additionally, the Department performed an economic analysis for CCS on the turbines EUs 1 – 30 at the GTP and found the costs to economically infeasible. Therefore, the Department considers this technology to be both technologically and economically infeasible for controlling GHG emissions from the small utility heaters.

(b) Good Combustion Practices and Clean Fuels
Discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3. GCP and clean fuels is a common technique for controlling GHG emissions. GHG emissions in the exhaust of liquid or gas-fired boilers and heaters are directly related to the carbon content in the fuel. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel, and is considered a feasible control technology for the small utility heaters.

Step 2 – Eliminate Technically Infeasible GHG Control Options for Small Utility Heaters
As explained in Step 1, CCS is not considered a technically feasible technology to control GHG emissions from gas-fired boilers and heaters rated at less than 100 MMBtu/hr.

Step 3 – Rank Remaining GHG Control Options for Small Utility Heaters
AGDC has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
According to the RBLC, clean fuels and good combustion practices are the applicable controls for GHG emissions for EUs 34 – 38. Since these are not add-on controls, there are no additional environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuels are the principle control method for GHG from gas-fired boilers and heaters rated at less than 100 MMBtu/hr.

Applicant Proposal
AGDC proposed to use good combustion practices and clean fuels for the small utility heaters EUs 34 – 38 as BACT for reducing GHG emissions. Additionally, EUs 34 and 35 will be limited to 500 hours per 12-month rolling period per boiler. GHG emissions from EUs 34 – 38 will not exceed 117.1 lb/MMBtu, which is the CO_2e emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Step 5 – Selection of GHG BACT for Small Utility Heaters
The Department's finding is that BACT for GHG emissions from the gas-fired boilers and heaters rated at less than 100 MMBtu/hr:

(a) GHG emissions from EUs 34 – 38 shall be controlled by maintaining good combustion practices and burning natural gas at all times the units are in operation;
(b) Limit operation of EUs 34 and 35 to no more than 500 hours per 12-month rolling period per boiler; and
(c) GHG emissions from EUs 34 – 38 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

8.0 VENT GAS DISPOSAL (FLARES)
The GTP will utilize four sets of flares (EUs 45 – 52) to handle the relief and blowdown requirements of the facility. EUs 45 – 48 contain the low pressure and high pressure (LP and HP) hydrocarbon flares, and EUs 49 – 52 contain the LP and HP CO_2 byproduct flares. These flare systems prevent the direct relief to the atmosphere of vent gases that contain VOC and GHG (in the form of CH_4). The flares will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants.

8.1 NOx
Possible NOx emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 8-1.

Table 8-1: NOx Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements	7	0.02 - 0.098
Flaring Minimization Plan	10	0.068
No Control Specified	8	0.05 - 0.068

Step 1 – Identify NOx Control Technologies for the Flares
From research, the Department identified the following technologies as available for NOx control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the GTP flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible NOx Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control NOx emissions from the flares.

Step 3 – Rank Remaining NOx Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 45 – 52. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for NOx emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 45 – 52 as BACT for reducing NOx emissions. Additionally, EUs 45 – 52 will be limited to 500 hours of flaring per 12-month rolling period per flare. NOx emissions from EUs 45 – 52 will not exceed 0.068 lb/MMBtu.

Step 5 – Selection of NOx BACT for the Flares

The Department's finding is that BACT for NOx emissions from the flares is as follows:

(a) NOx emissions from EUs 45 – 52 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 45 through 52 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[15] and

(c) NOx emissions from EUs 45 – 52 shall not exceed 0.068 lb/MMBtu averaged over a 3-hour period (AP-42 Table 13.5-1, NOx emissions rate for flare operations).

8.2 CO

Possible CO emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 8-2.

Table 8-2. CO Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements	7	0.08 - 0.37
Flaring Minimization Plan	12	0.31 – 0.37
No Control Specified	6	0.082 – 0.37

Step 1 – Identify CO Control Technologies for the Flares

From research, the Department identified the following technologies as available for CO control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous

[15] This 500 hour flaring limit does not include pilot and purge, emergency, or process upset flaring.

emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the GTP flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible CO Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control CO emissions from the flares.

Step 3 – Rank Remaining CO Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 45 – 52. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for CO emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 45 – 52 as BACT for reducing CO emissions. Additionally, EUs 45 – 52 will be limited to 500 hours of flaring per 12-month rolling period per flare. CO emissions from EUs 45 – 52 will not exceed 0.31 lb/MMBtu.

Step 5 – Selection of CO BACT for the Flares
The Department’s finding is that BACT for CO emissions from the flares is as follows:

(a) CO emissions from EUs 45 – 52 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 45 through 52 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare[15]; and

(c) CO emissions from EUs 45 – 52 shall not exceed 0.37 lb/MMBtu averaged over a 3-hour period (AP-42 Table 13.5-1, CO emissions rate for flare operations).

8.3 Particulates

Possible particulate emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 8-3.

Table 8-3: Particulate Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements	10	0.007 – 0.016
Flaring Minimization Plan	25	0.0019 – 0.0075
No Control Specified	9	0.0019 – 0.0264

Step 1 – Identify Particulate Control Technologies for the Flares
From research, the Department identified the following technologies as available for particulate control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the GTP flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible Particulate Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control particulate emissions from the flares.

Step 3 – Rank Remaining Particulate Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 45 – 52. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for Particulate emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 45 – 52 as BACT for reducing particulate emissions. Additionally, EUs 45 – 52 will be limited to 500 hours of flaring per 12-month rolling period per flare. Particulate emissions from EUs 45 – 52 will not exceed 40 µg/L (equivalent to 0.028 lb/MMBtu).

Step 5 – Selection of Particulate BACT for the Flares
The Department's finding is that BACT for particulate emissions from the flares is as follows:

(a) Particulate emissions from EUs 45 – 52 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 45 through 52 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare[15]; and

(c) Particulate emissions from EUs 45 – 52 shall not exceed 40 µg/L (0.028 lb/MMBtu) averaged over a 3-hour period (AP-42 Table 13.5-1, particulate emissions rate for lightly smoking flares).

8.4 SO_2
Possible SO_2 emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 8-4.

Table 8-4: SO_2 Controls for Flares

Control Technology	Number of Determinations	Emission Limits
Flare Work Practice Requirements	3	0.0001 – 0.0008 lb/hr
Flaring Minimization Plan	1	13,023.6 lb/hr
GCP & Clean Fuel	3	34 – 1,000 ppmv H_2S in fuel
No Control Specified	4	0.01 – 1,303.99 lb/hr

Step 1 – Identify SO_2 Control Technologies for the Flares
From research, the Department identified the following technologies as available for SO_2 control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan

Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the GTP flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

(d) Good Combustion Practices (GCP) and Clean Fuels
As discussed in detail in CO BACT Section 4.2, as well as the fuel specifications portion of particulate BACT Section 4.3, GCP and clean fuels is a common technique for controlling SO_2 emissions. SO_2 emissions in the exhaust of flares are directly related to the levels of sulfur in the fuel. As such, fuel specifications are a primary method of SO_2 emissions control and are a feasible control technology for the flares.

Step 2 – Eliminate Technically Infeasible SO_2 Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control SO_2 emissions from the flares.

Step 3 – Rank Remaining SO_2 Control Technologies for the Flares
AGDC has accepted the remaining three technically feasible control options for the flares EUs 45 – 52. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for SO_2 emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 45 – 52 as BACT for reducing SO_2 emissions. Additionally, EUs 45 – 52 will be limited to 500 hours of flaring per 12-month rolling period per flare. AGDC will utilize only natural gas in the flares EUs 45 – 52 with a total sulfur content not to exceed 96 ppmv during the initial phases of operation prior to the natural gas treatment trains becoming operational. Upon completion of the three natural gas treatment trains the total sulfur content of the fuel will not exceed 16 ppmv.

Step 5 – Selection of SO_2 BACT for the Flares
The Department's finding is that BACT for SO_2 emissions from the flares is as follows:

(a) SO_2 emissions from EUs 45 – 52 shall be minimized by burning natural gas, following proper flare work practice requirements, and establishing a flaring minimization plan;
(b) Prior to the completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 45 – 52 shall not exceed 96 ppmv;
(c) Upon completion of the three natural gas treatment trains, the total sulfur content of the natural gas combusted in EUs 45 – 52 shall not exceed 16 ppmv;
(d) Limit the number of hours EUs 45 through 52 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[15] and
(e) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for total sulfur content.

8.5 VOC
Possible VOC emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 8-5.

Table 8-5: VOC Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements	4	0.0054
Flaring Minimization Plan	9	0.0054
No Control Specified	4	0.0054 – 0.14

Step 1 – Identify VOC Control Technologies for the Flares
From research, the Department identified the following technologies as available for VOC control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the GTP flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible VOC Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control VOC emissions from flares.

Step 3 – Rank Remaining VOC Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 45 – 52. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for VOC emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 45 – 52 as BACT for reducing VOC emissions. Additionally, EUs 45 – 52 will be limited to 500 hours of flaring per 12-month rolling period per flare. VOC emissions from EUs 45 – 52 will not exceed 0.57 lb/MMBtu.

Step 5 – Selection of VOC BACT for the Flares
The Department's finding is that BACT for VOC emissions from the flares is as follows:

(a) VOC emissions from EUs 45 – 52 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 45 through 52 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare;[15] and

(c) VOC emissions from EUs 45 – 52 shall not exceed 0.57 lb/MMBtu averaged over a 3-hour period.

8.6 GHG
Possible GHG emission control technologies for the flares were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 19: Miscellaneous combustion (19:300 is specific to flares) and 50: Petroleum/Natural Gas Production and Refining. The search results were then filtered to include only emissions units with flares. The search results are summarized in Table 8-6.

Table 8-6: GHG Controls for Flares

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flare Work Practice Requirements & Flaring Minimization Plan	11	116.89 – 117
No Control Specified	2	116.89

Step 1 – Identify GHG Control Technologies for the Flares
From research, the Department identified the following technologies as available for GHG control of the flares:

(a) Flare Work Practice Requirements
Flare work practice requirements can be found in 40 CFR 60.18 (c) through (f). Flare design and monitoring are key elements in emissions performance of flares. Flares must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer. The Department considers proper flare design and good combustion practices as technically feasible control options for the flares.

(b) Flaring Minimization Plan
Flaring minimization plans define the procedures intended to reduce the frequency, magnitude, and duration of flaring events, without compromising plant operations or safety. By limiting the volume of gas going to the flare, all emissions types are minimized. The Department considers flaring minimization plans a technically feasible control options for the flares.

(c) Flare Gas Recovery
Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams, such as petroleum refineries, to reduce gaseous emissions to the atmosphere by recovering waste gas to be reused in the production process. However, flare gas recovery is not part of the GTP flare system design, as there would be no routine and continuous venting of gas to the flare. Therefore, consideration of flare gas recovery is unnecessary as a potential control technology.

Step 2 – Eliminate Technically Infeasible GHG Control Options for the Flares
As explained in Step 1, flare gas recovery is not feasible to control GHG emissions from the flares.

Step 3 – Rank Remaining GHG Control Technologies for the Flares
AGDC has accepted the remaining two technically feasible control options for the flares EUs 45 – 52. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
RBLC Review
A review of similar units in the RBLC indicates that use of flare work practice requirements (including proper flare design and good combustion practices) as well as a flaring minimization plan are the principle control methods for GHG emissions from flares. Since these are not add-on controls, there are no additional environmental impacts.

Applicant Proposal
AGDC proposed to use good combustion practices, proper flare design, and create a flaring minimization plan for the flares EUs 45 – 52 as BACT for reducing GHG emissions. Additionally, EUs 45 – 52 will be limited to 500 hours of flaring per 12-month rolling period per flare. GHG emissions from EUs 45 – 52 will not exceed 117.1 lb/MMBtu, which is the CO_2e emissions rates for burning natural gas in 40 CFR Part 98: Mandatory Greenhouse Gas Reporting. The total CO_2e emissions rate is calculated with the equation $CO_2(1) + CH_4(25) + N_2O(298)$.

Step 5 – Selection of GHG BACT for the Flares
The Department's finding is that BACT for GHG emissions from the flares is as follows:

(a) GHG emissions from EUs 45 – 52 shall be minimized by proper flare work practice requirements and establishing a flaring minimization plan;

(b) Limit the number of hours EUs 45 through 52 flare during startup, shutdown, and maintenance events, to no more than 500 hours per 12 consecutive month period per flare[15]; and

(c) GHG emissions from EUs 45 – 52 shall not exceed 117.1 lb/MMBtu averaged over a 3-hour period.

9.0 FUEL TANKS
GTP will have a total of nine fuel tanks (EUs 53 – 61). EUs 53 through 60 will hold diesel fuel with EU 53 having the largest capacity at 19,573 gallons. EU 61 will hold gasoline with a capacity of 10,000 gallons. These tanks will be used to supply fuel to the diesel EUs at the facility as well as support equipment and vehicles. The fuel tanks will emit VOCs. The following section provides the BACT review for VOC.

9.1 VOC
Possible VOC emission control technologies for fuel tanks were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 42.005 Petroleum Liquid Storage in Fixed Roof Tanks and 42.006 Petroleum Liquid Storage in Floating Roof Tanks. The search results are summarized in Table 9-1.

Table 9-1. VOC Control for Fuel Tanks

Control Technology	Number of Determinations	Emission Limits (tpy)
Floating Roof	30	0.88 - 18.57
Submerged Fill	7	0.8 - 72.5
Fixed Roof	5	0.8 - 72.5
Vapor Recovery System	4	3.95 - 7.33
NSPS	3	114.1
Leak Detection and Repair	1	28.3
No Control Specified	15	0.05 - 81.57

Step 1 – Identify VOC Control Technologies for Fuel Tanks
From research, the Department identified the following technologies as available for VOC control of the fuel tanks:

(a) Floating Roof
Floating roof tanks contain a roof that floats on the surface of the liquid that will rise and fall with the liquid level in the level in the tank, creating no vapor space except for when tanks have low liquid levels. External floating roof tanks are designed with a roof consisting of a double deck or pontoon single deck which rests or floats on the liquid being contained. An internal floating roof includes a fixed roof over the floating roof, to protect the floating roof from damage and deterioration. In general, the floating roof covers the entire liquid surface except for a small perimeter rim space. Under normal floating conditions, the roof floats essentially flat and is centered within the tank shell. The floating roof must be designed with perimeter seals (primary and secondary seals) which slide against the tank wall as the roof moves up and down. The use of perimeter seals minimizes emissions of VOCs from the tank. Sources of emissions from floating roof tanks include standing storage loss and withdrawal losses. Standing losses occur due to improper fits between tank seal and the tank shell. Withdrawal losses occur when liquid is removed from the tank, lowering the floating roof, revealing a liquid on the tank walls which vaporize. The Department considers floating roof tanks as a technically feasible control option for fuel tanks.

(b) Flare or Thermal Oxidizer
Enclosed flares combust the vent gases inside of the stack, avoiding the aesthetic concerns that can accompany visible flames produced by open flares. More burner tips are provided than for the open flare and the burner tips are located low enough inside the stack that there is no visible flame outside the stack. Air is drawn in through an adjustable opening in the bottom of the flare stack. A continuously lit pilot ensures that vent gases are combusted at the flare tip. A properly operated flare can achieve a destruction efficiency of 98 percent or greater. The GTP project does not currently include the operation of a thermal oxidizer, the addition of a new combustion unit to control emissions from the tanks would create an undesired additional source of emissions.

(c) Submerged Fill
Submerged filling involves filling a tank through an opening underneath the liquid surface level (pipe opening usually 12” or less from bottom of tank) in order to minimize the production of vapors. The use of submerged fill during tank loading operations can reduce vaporization of the liquid between 40 – 60% from traditional splash loading operations. Note that the use of submerged fill is a control technique specific to the filling of a tank and does not affect the day-to-day emissions of the tank. The Department considers submerged fill as a technically feasible control option for the fuel tanks.

(d) Vapor Recovery System
A vapor recovery system (VRS) can be used to draw vapors out of the storage tank, which are routed through a compressor. Compressed vapors may be used onsite as fuel for combustion units or routed to sales gas compressors for further compression to pipeline specifications. VRSs can recover over 95% of the hydrocarbon emissions that accumulate in the storage tanks.

(e) Leak Detection and Repair
A system of detecting tank leaks for repairs. This can range from a visual inspection to a computerized system with in-tank probes.

Step 2 – Eliminate Technically Infeasible VOC Control Options for Fuel Tanks
As explained in step 1, the addition of a thermal oxidizer/flare to control emissions would result in the addition of a combustion unit with a continuously lit pilot light that may offset the emissions reduction expected from the fuel tanks, which have modest VOC emissions to begin with. Therefore a flare or thermal oxidizer is eliminated from further consideration.

Step 3 – Rank Remaining VOC Control Options for Fuel Tanks
The following control technologies have been identified and ranked for control of VOC from the tanks:

(a) Floating Roof (99% Control)
(b) Vapor Recovery System (95% Control)
(c) Submerged Fill (40%-60% Control)
(d) Leak Detection and Repair (40% Control)

Step 4 – Evaluate the Most Effective Controls
A floating roof system is the most effective control for the fuel tanks at GTP. A floating roof system will not have any harsh environmental impacts and requires no consumables. Separately, submerged fill has the best VOC emissions control without requiring an add-on control, other than proper tank design.

RBLC Review
A review of similar units in the RBLC indicates add-on control technology is not practical for small tanks of diesel and gasoline fuel. Based on the small potential to emit of less than one tpy for all nine tanks combined, add on controls are not a cost effective control technology for GTP's tanks.

Applicant Proposal
AGDC provided an economic analysis of a vapor recovery system to demonstrate that this control is not economically feasible for the fuel tank EUs 53 through 61. A summary of AGDC's analysis for the fuel tanks are shown below in Tables 9-2 and 9-3. The case with all tanks combined on the same VRS (Table 9-2) is presented as a conservative estimate of cost-effectiveness. In reality, tanks storing gasoline would not be connected to the same VRS as tanks storing diesel fuel (Table 9-3) due to potential cross-contamination issues. However, for this analysis, if all tanks connected to the same VRS is not cost-effective, the cost-effectiveness of separate VRS systems would likewise be less cost-effective.

Table 9-2: AGDC Economic Analysis for Technically Feasible VOC Controls (EUs 53-61)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
VRS	0.03	0.55	$46,726	$16,285	$29,462
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

Table 9-3: AGDC Economic Analysis for Technically Feasible VOC Controls (EUs 53-60)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
VRS	0.0002	0.0032	$46,726	$16,285	$5,049,828
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

AGDC contends that the economic analysis indicates the level of VOC reduction from VRS does not justify the use of VRS for the fuel tanks based on the excessive cost per ton of VOC removed per year.

AGDC proposes the following as BACT for VOC emissions from the fuel tanks:

(a) VOC emissions from the operation of the fuel tanks EUs 53 – 61 will be controlled with the use of submerged fill; and

(b) VOC emissions from fuel tanks EUs 53 – 61 will not exceed 0.59 tons per year.

Department Evaluation of BACT for VOC Emissions from Fuel Tank

The Department revised the cost analyses to reflect the equipment life revised to a 25 year lifespan and adjusted the interest rate to the current bank prime interest rate of 5.5%. A summary of the analyses for all fuel tanks EUs 53 through 61 is shown in Table 9-4, and a summary of the analyses for the diesel fuel tanks EUs 53 through 60 is shown in Table 9-5. Note that the cost analysis is for all EUs combined.

Table 9-4: Department Economic Analysis for Technically Feasible VOC Controls (EUs 53-61)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
VRS	0.03	0.55	$46,726	$12,391	$22,417
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

Table 9-5: Department Economic Analysis for Technically Feasible VOC Controls (EUs 53-60)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
VRS	0.0002	0.0032	$46,726	$12,391	$3,842,325
Capital Recovery Factor = 0.0590 (3.25% interest rate for a 25 year equipment life)					

The Department's economic analysis indicates the level of VOC reduction does not justify the use of VRS as BACT for the fuel tanks at the Gas Treatment Plant.

Step 5 – Selection of VOC BACT for Fuel Tanks

The Department's finding is that BACT for VOC emissions from the fuel tanks is as follows:

(a) VOC emissions from the operation of the fuel tanks EUs 53 – 61 will be controlled with the use of submerged fill;

(b) VOC emissions from fuel tanks EUs 53 – 61 will not exceed 0.59 tons per year combined; and

(c) Initial compliance with the proposed VOC emission limit will be demonstrated by supplying the Department with schematics of the fuel tank EU 61 demonstrating that the submerged fill pipe is no more than 6 inches from the bottom of the tank.

Appendix C: BACT Summary

Table C-1. NOx BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6 & 13 – 18	386 MMBtu/hr Cogeneration Compressor Gas Turbines with 190 MMBtu/hr Waste Heat Recovery Units	17 ppmvd at 15% O_2	Dry Low NOx; Good Combustion Practices
7 – 12 & 19 – 24	291 MMBtu/hr Cogeneration Compressor Gas Turbines with 140 MMBtu/hr Waste Heat Recovery Units	17 ppmvd at 15% O_2	Dry Low NOx; Good Combustion Practices
25 – 30	386 MMBtu/hr Simple Cycle Power Generation Gas Turbines	15 ppmvd at 15% O_2	Dry Low NOx; Good Combustion Practices
31 – 33	275 MMBtu/hr Gas-Fired Building Medium Heaters	0.036 lb/MMBtu	Low NOx Burners; Good Combustion Practices
34 & 35	Buyback Gas Bath Heaters (Gas-Fired, ≤ 25 MMBtu/hr)	0.036 lb/MMBtu	Low NOx Burners; Limited Operation; Good Combustion Practices
36 – 38	Operations Camp Heaters (Gas-Fired, 32 MMBtu/hr)	0.036 lb/MMBtu	Low NOx Burners; Good Combustion Practices
39	4,060 hp Black Start Generator (ULSD)	3.3 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
40 – 42	Firewater Pump Engines (ULSD, 250 hp)	3.6 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
43 & 44	Emergency Diesel Generators (ULSD, ≤ 335 hp)	3.6 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
45 – 52	Vent Gas Disposal (Flares) 1.3 – 76,000 Mscf/hr	0.068 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Table C-2. CO BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6 & 13 – 18	386 MMBtu/hr Cogeneration Compressor Gas Turbines with 190 MMBtu/hr Waste Heat Recovery Units	5 ppmvd at 15% O_2	Oxidation Catalyst; Good Combustion Practices
7 – 12 & 19 – 24	291 MMBtu/hr Cogeneration Compressor Gas Turbines with 140 MMBtu/hr Waste Heat Recovery Units	5 ppmvd at 15% O_2	Oxidation Catalyst; Good Combustion Practices
25 – 30	386 MMBtu/hr Simple Cycle Power Generation Gas Turbines	15 ppmvd at 15% O_2	Clean Fuel; Good Combustion Practices
31 – 33	275 MMBtu/hr Gas-Fired Building Medium Heaters	0.007 lb/MMBtu	Oxidation Catalyst; Good Combustion Practices
34 & 35	Buyback Gas Bath Heaters (Gas-Fired, ≤ 25 MMBtu/hr)	0.087 lb/MMBtu	Clean Fuel; Limited Operation; Good Combustion Practices
36 – 38	Operations Camp Heaters (Gas-Fired, 32 MMBtu/hr)	0.087 lb/MMBtu	Clean Fuel; Good Combustion Practices
39	4,060 hp Black Start Generator (ULSD)	3.3 g/hp-hr	Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII
40 – 42	Firewater Pump Engines (ULSD, 250 hp)	3.3 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
43 & 44	Emergency Diesel Generators (ULSD, ≤ 335 hp)	3.3 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
45 – 52	Vent Gas Disposal (Flares) 1.3 – 76,000 Mscf/hr	0.37 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Table C-3. Particulate Matter (PM, PM-10 & PM-2.5) BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6 & 13 – 18	386 MMBtu/hr Cogeneration Compressor Gas Turbines with 190 MMBtu/hr Waste Heat Recovery Units	0.0063 lb/MMBtu	Clean Fuel; Good Combustion Practices
7 – 12 & 19 – 24	291 MMBtu/hr Cogeneration Compressor Gas Turbines with 140 MMBtu/hr Waste Heat Recovery Units	0.0063 lb/MMBtu	Clean Fuel; Good Combustion Practices
25 – 30	386 MMBtu/hr Simple Cycle Power Generation Gas Turbines	0.0070 lb/MMBtu	Clean Fuel; Good Combustion Practices
31 – 33	275 MMBtu/hr Gas-Fired Building Medium Heaters	0.0079 lb/MMBtu	Clean Fuel; Good Combustion Practices
34 & 35	Buyback Gas Bath Heaters (Gas-Fired, ≤ 25 MMBtu/hr)	0.0079 lb/MMBtu	Clean Fuel; Limited Operation; Good Combustion Practices
36 – 38	Operations Camp Heaters (Gas-Fired, 32 MMBtu/hr)	0.0079 lb/MMBtu	Clean Fuel; Good Combustion Practices (GCP)
39	4,060 hp Black Start Generator (ULSD)	0.045 g/hp-hr	GCP & ULSD; Limited Operation; 40 CFR 60 Subpart IIII
40 – 42	Firewater Pump Engines (ULSD, 250 hp)	0.19 g/hp-hr	GCP & ULSD; Limited Operation; 40 CFR 60 Subpart IIII
43 & 44	Emergency Diesel Generators (ULSD, ≤ 335 hp)	0.19 g/hp-hr	GCP & ULSD; Limited Operation; 40 CFR 60 Subpart IIII
45 – 52	Vent Gas Disposal (Flares) 1.3 – 76,000 Mscf/hr	40 µg/L 0.028 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Table C-4. SO_2 BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6 & 13 – 18	386 MMBtu/hr Cogeneration Compressor Gas Turbines with 190 MMBtu/hr Waste Heat Recovery Units	≤96 ≤16 ppmv sulfur content in natural gas: Initial limit and lower limit with completed treatment trains	Clean Fuel; Good Combustion Practices
7 – 12 & 19 – 24	291 MMBtu/hr Cogeneration Compressor Gas Turbines with 140 MMBtu/hr Waste Heat Recovery Units	≤96 ≤16 ppmv sulfur content in natural gas: Initial limit and lower limit with completed treatment trains	Clean Fuel; Good Combustion Practices
25 – 30	386 MMBtu/hr Simple Cycle Power Generation Gas Turbines	≤96 ≤16 ppmv sulfur content in natural gas: Initial limit and lower limit with completed treatment trains	Clean Fuel; Good Combustion Practices
31 – 33	275 MMBtu/hr Gas-Fired Building Medium Heaters	≤96 ≤16 ppmv sulfur content in natural gas: Initial limit and lower limit with completed treatment trains	Clean Fuel; Good Combustion Practices
34 & 35	Buyback Gas Bath Heaters (Gas-Fired, ≤ 25 MMBtu/hr)	≤96 ≤16 ppmv sulfur content in natural gas: Initial limit and lower limit with completed treatment trains	Clean Fuel; Limited Operation; Good Combustion Practices

36 – 38	Operations Camp Heaters (Gas-Fired, 32 MMBtu/hr)	≤96 ≤16	ppmv sulfur content in natural gas. Initial limit and lower limit with completed treatment trains	Clean Fuel; Good Combustion Practices
39	4,060 hp Black Start Generator (ULSD)	≤15	ppmw sulfur content in diesel fuel	Good Combustion Practices & ULSD; Limited Operation; 40 CFR 60 Subpart IIII
40 – 42	Firewater Pump Engines (ULSD, 250 hp)	≤15	ppmw sulfur content in diesel fuel	Good Combustion Practices & ULSD; Limited Operation; 40 CFR 60 Subpart IIII
43 & 44	Emergency Diesel Generators (ULSD, ≤ 335 hp)	≤15	ppmw sulfur content in diesel fuel	Good Combustion Practices & ULSD; Limited Operation; 40 CFR 60 Subpart IIII
45 – 52	Vent Gas Disposal (Flares) 1.3 – 76,000 Mscf/hr	≤96 ≤16	ppmv sulfur content in natural gas: Initial limit and lower limit with completed treatment trains	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Table C-5. VOC BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6 & 13 – 18	386 MMBtu/hr Cogeneration Compressor Gas Turbines with 190 MMBtu/hr Waste Heat Recovery Units	0.0022 lb/MMBtu	Oxidation Catalyst; Good Combustion Practices
7 – 12 & 19 – 24	291 MMBtu/hr Cogeneration Compressor Gas Turbines with 140 MMBtu/hr Waste Heat Recovery Units	0.0022 lb/MMBtu	Oxidation Catalyst; Good Combustion Practices
25 – 30	386 MMBtu/hr Simple Cycle Power Generation Gas Turbines	0.0022 lb/MMBtu	Clean Fuel; Good Combustion Practices
31 – 33	275 MMBtu/hr Gas-Fired Building Medium Heaters	0.0029 lb/MMBtu	Oxidation Catalyst; Good Combustion Practices
34 & 35	Buyback Gas Bath Heaters (Gas-Fired, ≤ 25 MMBtu/hr)	0.0057 lb/MMBtu	Clean Fuel; Limited Operation; Good Combustion Practices
36 – 38	Operations Camp Heaters (Gas-Fired, 32 MMBtu/hr)	0.0057 lb/MMBtu	Clean Fuel; Good Combustion Practices
39	4,060 hp Black Start Generator (ULSD)	0.18 g/hp-hr	Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII
40 – 42	Firewater Pump Engines (ULSD, 250 hp)	0.19 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
43 & 44	Emergency Diesel Generators (ULSD, ≤ 335 hp)	0.19 g/hp-hr	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
45 – 52	Vent Gas Disposal (Flares) 1.3 – 76,000 Mscf/hr	0.57 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan
53 – 61	Fuel Tanks (Diesel and Gasoline)	0.59 tpy	Submerged Fill

Table C-6. GHG BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 6 & 13 – 18	386 MMBtu/hr Cogeneration Compressor Gas Turbines with 190 MMBtu/hr Waste Heat Recovery Units	117.1 lb/MMBtu	Clean Fuel; Good Combustion Practices
7 – 12 & 19 – 24	291 MMBtu/hr Cogeneration Compressor Gas Turbines with 140 MMBtu/hr Waste Heat Recovery Units	117.1 lb/MMBtu	Clean Fuel; Good Combustion Practices
25 – 30	386 MMBtu/hr Simple Cycle Power Generation Gas Turbines	117.1 lb/MMBtu	Clean Fuel; Good Combustion Practices
31 – 33	275 MMBtu/hr Gas-Fired Building Medium Heaters	117.1 lb/MMBtu	Clean Fuel; Good Combustion Practices
34 & 35	Buyback Gas Bath Heaters (Gas-Fired, ≤ 25 MMBtu/hr)	117.1 lb/MMBtu	Clean Fuel; Limited Operation; Good Combustion Practices
36 – 38	Operations Camp Heaters (Gas-Fired, 32 MMBtu/hr)	117.1 lb/MMBtu	Clean Fuel; Good Combustion Practices
39	4,060 hp Black Start Generator (ULSD)	163.6 lb/MMBtu	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
40 – 42	Firewater Pump Engines (ULSD, 250 hp)	163.6 lb/MMBtu	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
43 & 44	Emergency Diesel Generators (ULSD, ≤ 335 hp)	163.6 lb/MMBtu	Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
45 – 52	Vent Gas Disposal (Flares) 1.3 – 76,000 Mscf/hr	117.1 lb/MMBtu	Limited Operation; Flare Work Practices; Flaring Minimization Plan

Appendix D: Modeling Report

Alaska Department of Environmental Conservation
Air Permit Program

Review of

AGDC's Ambient Demonstration

for the

Alaska LNG Project's

Gas Treatment Plant

Construction Permit AQ1524CPT01

Prepared by: Alan Schuler
Reviewed by: James Renovatio

Date: August 13, 2020

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1. INTRODUCTION

This report summarizes the Alaska Department of Environmental Conservation's (Department's) findings regarding the ambient analysis submitted by the Alaska Gasline Development Corporation (AGDC) for the Gas Treatment Plant (GTP) stationary source as an element of the Alaska Liquefied Natural Gas Project (AK LNG Project). AGDC submitted this analysis in support of their December 29, 2017 application for Air Quality Control Construction Permit AQ1524CPT01, provided in comport with the Prevention of Significant Deterioration (PSD) requirements listed in 18 AAC 50.306 and the major source of hazardous air pollutant (HAP) requirements listed in 18 AAC 50.316. The potential GTP emissions trigger the PSD permit requirements for the following air pollutants: oxides of nitrogen (NOx), particulate matter with an aerodynamic diameter of 10 microns or less (PM-10), particulate matter with an aerodynamic diameter of 2.5 microns or less (PM-2.5), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOC), and greenhouse gases (GHG).

AGDC provided the PSD source impact analysis required under 40 CFR 52.21(k), the pre-construction monitoring analysis required under 40 CFR 52.21(m)(1), and the additional impact analysis required under 40 CFR 52.21(o). AGDC demonstrated that operating the GTP emissions units (EUs) within the restrictions listed in this report will not cause or contribute to a violation of the following Alaska Ambient Air Quality Standards (AAAQS) listed in 18 AAC 50.010: 1-hour nitrogen dioxide (NO_2), annual NO_2, 24-hour PM-10, 24-hour PM-2.5, annual PM-2.5, 1-hour SO_2, 3-hour SO_2, 24-hour SO_2, annual SO_2, 1-hour CO, 8-hour CO, and 8-hour ozone (O_3). AGDC also demonstrated that the GTP emissions will not cause or contribute to a violation of the following Class II maximum allowable increases (increments) described in 18 AAC 50.020: annual NO_2, 24-hour PM-10, annual PM-10, 24-hour PM-2.5, annual PM-2.5, 3-hour SO_2, 24-hour SO_2, and annual SO_2.[1]

2. PROJECT BACKGROUND

GTP will be a new stationary source located within the Prudhoe Bay Unit (PBU) of the Alaska North Slope. The project scope is fully described in AGDC's *Resource Report 1* (General Project Information) of the AK LNG Project, which AGDC provided as Attachment 2 of their permit application. In summary, GTP would treat and process gas received from the Alaska North Slope for delivery into a gas pipeline, which would deliver the gas to a Liquefaction Plant where the gas would be liquefied and transported to market. GTP will have three parallel production trains to treat and process the gas. Each train will include two Treated Gas Compression turbines and two Byproduct (CO_2) Compression turbines. Additional background information regarding GTP, the ambient demonstration requirements, and various procedural issues, are provided below.

2.1. Area Classification

The project site is in an area that is unclassified in regards to compliance with the AAAQS. For purposes of increment compliance, the project site is within a Class II area of the

[1] There are no ambient demonstration requirements for GHG emissions since there are no GHG AAAQS or increments.

Northern Alaska Intrastate Air Quality Control Region. The nearest Class I area,[2] Denali National Park, is located approximately 750 kilometers (km) to the south.

2.2. Ambient Demonstration Requirements

The State of Alaska's PSD requirements are described in 18 AAC 50.306. PSD applicants must essentially comply with the federal PSD requirements in 40 CFR 52.21. Except as noted in 40 CFR 52.21(i), the ambient requirements include:

- Stack Height considerations, per 40 CFR 52.21(h);
- A Source Impact Analysis, i.e., an ambient demonstration for the PSD-triggered pollutants with an associated ambient air quality standard or increment, per 40 CFR 52.21(k);
- An Air Quality Analysis, i.e., pre-construction monitoring data, for the PSD-triggered pollutants with an associated ambient air quality standard or increment, per 40 CFR 52.21(m);
- An Additional Impact Analysis per 40 CFR 52.21(o); and
- A Class I Impact Analysis, for stationary sources that may affect a Class I area, per 40 CFR 52.21(p).

GTP is located too far from Denali National Park to warrant a Class I Impact Analysis. The Department nevertheless notified the National Park Service (NPS) of the pending permit application upon receipt of the PSD modeling protocol (see Section 2.4.2 of this report) and asked them to confirm that they would not be requesting a PSD Class I analysis under 40 CFR 52.21(p).[3] The NPS confirmed that they would not be requesting a Class I analysis on October 11, 2017.[4]

There are no ambient demonstration requirements under the major HAP permit classification. Therefore, AGDC was only required to provide the PSD demonstrations described at the beginning of Section 2.2.

2.3. Increments and Baseline Dates

For air quality modeling purposes, the term "increment" regards the maximum allowed increase in ambient concentration that may occur in a given area. The increment is determined relative to the "baseline concentration," which reflects the concentration that occurred, or was accounted for, at the time of a set baseline date. Congress set January 6, 1975 as the major source baseline date for the 24-hour and annual PM-10 increments, and

[2] Class I areas are defined as national parks over 6,000 acres and wilderness areas and memorial parks over 5,000 acres, established as of 1977. All other federally managed areas are designated as Class II areas. The Class I areas within Alaska are listed in Table 1 of 18 AAC 50.015(c)(2).

[3] The Department initially contacted the NPS in a September 18, 2017 email from Alan Schuler to John Notar, *AK LNG GTP Protocol*; and sent a follow-up email from Alan Schuler to Andrea Stacy, *FW: AK LNG GTP Protocol*, on October 10, 2017.

[4] Email from Andrea Stacy (NPS) to Alan Schuler (Department), *Re: FW: AK LNG GTP Protocol*; October 11, 2017.

the 3-hour, 24-hour, and annual SO_2 increments. EPA established February 8, 1988 as the major source baseline date for the annual NO_2 increment, and October 20, 2010 as the major source baseline date for the 24-hour and annual PM-2.5 increments. There are no 1-hour SO_2 or 1-hour NO_2 increments. The minor source baseline dates for the Northern Alaska Intrastate Air Quality Control Region are listed in Table 2 of 18 AAC 50.020. All of the combustion-related EUs at GTP will consume increment for the pollutants and averaging periods described within this paragraph since the emissions will occur after the applicable major source baseline dates.

2.4. Additional Comments Regarding Various Procedural Issues

2.4.1. Interface with the National Environmental Policy Act

AGDC conducted various air quality demonstrations under the National Environmental Policy Act (NEPA) prior to submitting their permit application for GTP.[5] They therefore relied on these previous demonstrations, to the extent possible, for the ambient analyses required under PSD. This type of coordinated approach is encouraged by EPA under 40 CFR 52.21(s). The Department has not adopted this citation by reference (since it has no control over the federal actions conducted under NEPA), but the Department nevertheless agrees that the analyses should be consistent where possible.

The Department notes, however, that while the PSD and NEPA requirements contain a number of similar air quality provisions, they are not fully identical. This report does not delve into those differences; but AGDC summarized them with respect to the GTP project in Attachment 4 of their PSD modeling protocol.

2.4.2. Modeling Protocol Submittal

AGDC submitted a modeling protocol for the PSD ambient demonstration for GTP on September 18, 2017. They submitted supplemental information on October 11, 2017. The Department approved the protocol, with comment, on December 13, 2017.

The protocol stated that that the two nearest off-site facilities, the PBU Central Compressor Plant (CCP) and PBU Central Gas Facility (CGF),[6] would be included in the cumulative impact analyses. The protocol also included the results of a wind tunnel study that AGDC conducted to determine more realistic downwash parameters for some of the CCP/CGF exhaust stacks – see related discussion in Section 5.11 (**Downwash**) of this report.

The Department asked the Region 10 (R10) office of the U.S. Environmental Protection Agency (EPA) for technical assistance in reviewing the wind tunnel study, along with the resulting Equivalent Building Dimensions (EBDs). R10 provided their recommendations in a December 11, 2017 letter, *Review of equivalent building*

5 The Federal Energy Regulatory Commission (FERC) is the lead agency for the NEPA review.
6 CCP and CGF are a single stationary source for purposes of Title I and Title V permitting.

dimension study for the Alaska LNG Gas Treatment Plant. The Department accepts R10's recommendations, which are summarized below:

- AGDC's EBD study complies with current EPA guidance; and
- The EBD results may be used in AGDC's cumulative modeling analyses for GTP.[7]

2.4.3. Guideline on Air Quality Models

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

EPA has made a number of updates to the *Guideline on Air Quality Models* (Guideline) over time. The Department used the 2005 version of the Guideline for the GTP modeling review since that was the version adopted by reference in 18 AAC 50.040(f) at the time of the protocol review.[8] EPA had previously promulgated an update to the Guideline on January 17, 2017, but they also provided a one year transition period for the permitting authorities to incorporate the update into their air permit programs. EPA further stated:

> *During the 1-year period following promulgation, protocols for modeling analyses bases on the 2005 version of the Guideline, which are submitted in a timely manner, may be approved at the discretion of the reviewing authority*.

The Department approved AGDC's PSD modeling protocol on December 13, 2017, which is within the 1-year transition period. The Department's reliance on the 2005 version of the Guideline for the GTP permit is therefore consistent with State rule, and allowed under Federal rule.

2.4.4. Application Submittal

AGDC submitted their permit application on December 28, 2017. They retransmitted the application on February 14, 2018 due to missing/corrupted electronic files in the original submittal. The Department requested additional information (which included

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7 R10 limited their recommended approval of AGDC's EBD study to just the GTP cumulative impact analyses. R10 stated that further review is warranted prior to using the EBD study results in a permit application for CCP/CGF. They also provided recommendations to EPA's Model Clearinghouse regarding future EBD guidance. The Department acknowledged these additional recommendations in its approval of the PSD modeling protocol, but it did not elaborate on them since those issues are beyond the scope of the GTP Project.

8 At the time of the protocol review, 18 AAC 50.040(f) referred to the version of the Guideline "*revised as of July 1, 2015*." The date refers to the latest version of 40 CFR 51 available when 18 AAC 50.040(f) was last updated. However, the latest version of the Guideline at that time was the version published in the Federal Register on November 9, 2005.

modeling-related information) on March 6, 2018. AGDC provided the missing documents on May 1, 2018, and the associated modeling files on May 4, 2018.[9]

3. REPORT OUTLINE

The Department's findings regarding AGDC's approach for meeting the pre-construction monitoring requirement in 40 CFR 52.21(m) is described in Section 4 (**Pre-Construction Monitoring Data**) of this report. The Department's findings regarding the additional impact analysis conducted under 40 CFR 52.21(o) is described in Section 8 (**Additional Impact Analysis**) of the report.

AGDC used a variety of means to address the ambient demonstration requirement in 40 CFR 52.21(k). AGDC used computer analyses (modeling) to predict the ambient NO_2, SO_2, PM-10, CO, and direct PM-2.5 air quality impacts; ambient data to represent the existing secondary PM-2.5 impacts; and a qualitative analysis to address the ambient O_3 impacts and project-related secondary PM-2.5 impacts. The Department's findings regarding AGDC's NO_2, SO_2, CO, PM-10, and PM-2.5 modeling analyses are provided in Section 5 (**Source Impact Analyses**) of this report. The results from these assessments are discussed in Section 6 (**Modeling Results and Discussion**). The Department's findings regarding AGDC's O_3 analysis is in Section 7 (**Ozone Impacts**) of the report.

4. PRE-CONSTRUCTION MONITORING DATA

40 CFR 52.21(m)(1) requires PSD applicants to submit ambient air monitoring data describing the air quality in the vicinity of the project, unless the existing concentration or the project impact is less than the applicable Significant Monitoring Concentration provided in 40 CFR 52.21(i)(5). The requirement only pertains to those pollutants that are subject to PSD review and have a National Ambient Air Quality Standard (NAAQS).[10] If monitoring is required, the data are to be collected prior to construction. Hence, these data are referred as "pre-construction monitoring" data. Ambient "background" data may also be needed to supplement the estimated ambient impact from the proposed project. AGDC's approach for meeting the pre-construction data requirement is discussed below. Their approach for meeting the "background" data needs is described in Section 5.15 (**Off-Site Impacts**) of this report.

Pre-construction monitoring data must be collected at a location and in a manner that is consistent with the EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which the Department adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of existing and proposed maximum impacts, the data must be current, and the data must meet PSD quality

[9] The Department made additional information requests regarding non-modeling related issues, but they are not discussed in this Modeling Report.

[10] EPA has the authority under 40 CFR 52.21(m)(1)(ii) to require pre-construction monitoring for PSD-triggered pollutants that do not have a NAAQS (when they have shown a need for the data), but they have not made this determination for those pollutants.

assurance requirements. The current quality assurance requirements are described in 18 AAC 50.215(a).

AGDC used ambient pollutant data measured by BP Exploration Alaska, Inc. (BPXA) at their CCP monitoring station to fulfill the pre-construction monitoring requirement. They provided their justification for using this dataset in Attachment 3 of their permit application. As noted by AGDC, the Department originally approved the CCP site in March 21, 2011 when the Project was under the auspices of the Alaska Pipeline Project (APP).[11, 12] The Department confirmed the adequacy of this location during a January 15, 2015 pre-application meeting, and in its December 13, 2017 approval of the PSD modeling protocol (see Section 2.4.2 of this report).

AGDC provided data from calendar year 2015 in Attachment 3 of their permit application. This was the most recent year of Department-approved data when they were preparing their application. The Department has subsequently approved the CCP data from 2016 as well.[13]

The maximum concentrations (as measured according to the form of the given AAAQS) from both 2015 and 2016 are provided in Table 1 below. The Department is reporting the gaseous pollutants on a mass basis (micrograms per cubic meter – $\mu g/m^3$) which is the convention used in modeling, rather than the volumetric basis (parts per million – ppm) typically used in monitoring reports. Particulates are only measured and reported on a mass basis and are therefore, presented on a mass basis. Table 1 shows that the local air quality currently complies with the AAAQS for each PSD-triggered pollutant with an ambient air quality standard.

Table 1. Pre-Construction Monitoring Data (from BPXA's CCP Monitoring Station)

Air Pollutant	Avg. Period	Max. Conc. ($\mu g/m^3$) measured in Calendar Year: 2015	2016	AAAQS ($\mu g/m^3$)
NO_2	1-hour	147	167	188
	Annual	18.8	20.7	100
SO_2	1-hour	22.8	24.4	196
	3-hour	23.6	0.0	1,300
	24-hour	20.2	26.2	365
	Annual	3.4	2.6	80
PM-10	24-hour	60	40	150

11 Letter from Alan Schuler (Department) to Myron Fedak (Alaska Pipeline Project); *Approval of Revised Ambient Air Quality Monitoring Site for the Alaska Pipeline Project Gas Treatment Plant*; March 21, 2011.

12 The Department's March 21, 2011 approval was for a stand-alone monitoring station located roughly 100-feet from BPXA's CCP monitoring station. However, the Department confirmed in a July 1, 2011 email to APP's consultant (AECOM) that BPXA's CCP monitoring site would be equally adequate. The email was from Alan Schuler to Jamie Christopher and Tom Damiana of AECOM, and had the subject line, *RE: Can we have a quick call regarding the [AK Pipeline] GTP Monitoring in Prudhoe Bay Today*.

13 *Alaska Department of Environmental Conservation Findings Regarding the BP Exploration (Alaska) Inc. (BPXA) 2016 Prudhoe Bay Unit CCP Ambient Air Monitoring Program Data*; December 14, 2017.

Air Pollutant	Avg. Period	Max. Conc. ($\mu g/m^3$) measured in Calendar Year: 2015	2016	AAAQS ($\mu g/m^3$)
PM-2.5	24-hour	9	16	35
	Annual	3.2	3.0	12
O_3	8-hour	82	82	140
CO	1-hour	1,145	1,140	40,000
	8-hour	1,145	1,140	10,000

5. SOURCE IMPACT ANALYSES

As previously mentioned in Section 3, AGDC conducted air quality modeling analyses to estimate their ambient NO_2, SO_2, CO, PM-10, and direct PM-2.5 impacts. The various aspects of their modeling analyses are discussed below.

5.1. Approach

AGDC modeled the "normal operations" scenario where all three production trains would be operating at full capacity. Additional information regarding this scenario may be found in Section 4.1.1 of the GTP Modeling Report that they submitted to FERC (Appendix F of Resource Report 9). AGDC did not model the other operational scenarios (e.g., plant start-up, early plant operations, and maintenance operations) since those scenarios would have fewer emissions and smaller ambient impacts. They likewise did not model the construction phase for the reasons described in Section 5.6.3 of this report. AGDC's approach of just modeling the normal operations scenario is reasonable.

AGDC used a two-step approach for modeling the normal operations scenario. They first compared the ambient impact from just the GTP EUs (i.e., the project impacts) to the significant impact levels (SILs) listed in Table 5 of 18 AAC 50.215(d). Impacts less than the SIL are considered negligible. They then conducted a cumulative impact analysis for those pollutants and averaging periods with significant impacts. The cumulative impacts are compared to the AAAQS or increment, as applicable.

A cumulative AAAQS demonstration incorporates the impacts from natural and regional sources, along with long-range transport from far away sources. The impacts are accounted for through a combination of modeling and representative air quality monitoring data (aka background data). EPA discusses this overall approach in Section 8.2 of the Guideline. As stated in Section 8.2.3, "…*all sources expected to cause a significant concentration gradient in the vicinity of the [applicant's source] should be explicitly modeled.*" The impact from other sources can be accounted for through representative background data.

The increment consuming impact from off-site sources must likewise be accounted for in a cumulative increment demonstration. The approach for incorporating these impacts must be evaluated on a case-specific basis for each pollutant. Background data is not generally used in a cumulative increment analysis since it typically overstates the off-site increment consumption – i.e., it reflects the total air quality concentration rather than the *change* in concentration subsequent to the increment baseline date (see Section 2.3 of this report). Applicants instead typically model the nearby increment consuming EUs, and when warranted, the off-site increment expanding EUs.

As subsequently discussed in Section 6 (**Modeling Results and Discussion**) of this report, the project impacts for GTP exceed the SIL for most of the modeled pollutants and averaging periods. AGDC therefore included the nearby CCP/CGF EUs in their cumulative impact analyses since the CCP/CGF stationary source likely has significant concentration gradients near GTP. The following sub-sections provide additional details regarding AGDC's modeling analysis.

5.2. Model Selection

There are a number of air dispersion models available to applicants and regulators. EPA lists these models in the Guideline. AGDC used EPA's AERMOD Modeling System (AERMOD) for their ambient analyses. AERMOD is an appropriate modeling system for this permit application.

The AERMOD Modeling System consists of three major components: AERMAP, used to process terrain data and develop elevations for the receptor grid and EUs; AERMET, used to process the meteorological data; and the AERMOD dispersion model, used to estimate the ambient pollutant concentrations.

AGDC used the versions of AERMET and AERMOD that were current at the time that they conducted their NEPA analysis: AERMET version 15181 (AERMET 15181) and AERMOD version 15181 (AERMOD 15181). AERMAP was not used, nor required, since the North Slope coastal plain is considered featureless (see Section 5.5 of this report).

EPA has issued two AERMOD and AERMET updates subsequent to AGDC's NEPA analysis. EPA released the first update on December 20, 2016, with a subsequent correction to AERMOD on January 18, 2017. EPA identified the updates as AERMET version 16216 (AERMET 16216) and AERMOD version 16216r (AERMOD 16216r). AGDC acknowledged these updates in their PSD modeling protocol, but they also expressed a desire to maintain consistency with the NEPA analysis (see the related discussion in Section 2.4.1). However, AGDC stated that they would conduct a sensitivity analysis to confirm that the results using AERMOD/AERMET 15181 are still valid. The Department conditionally approved AGDC's proposed use of AERMOD/AERMET 15181, but noted that AGDC would need to use the current version of AERMET and AERMOD if:

- The sensitivity analysis shows that the maximum impacts may have been underestimated when using AERMET/AERMOD 15181;
- There are substantive changes in the EU inventory, emissions, or stack parameters that warrant an updated modeling analysis, and/or;

- AGDC (or the Department) finds that the tall tower meteorological data collected at Deadhorse leads to notably greater impacts than the A-Pad meteorological data used for the NEPA analysis (see Section 5.3.3 of this report).

AGDC provided the sensitivity analysis as Attachment 8 of their permit application. AGDC reran the cumulative impact analysis for the worst-case pollutants (1-hour NO_2 and 24-hour PM-2.5) for all five meteorological data years (see Section 5.3 of this report) using AERMET 16216 and AERMOD 16216r. The 1-hour NO_2 impacts were identical to the NEPA results to the second decimal. The 24-hour PM-2.5 impacts were identical to the NEPA results to the fifth decimal. AGDC's sensitivity analysis demonstrates that AERMET/AERMOD 15181 does not underestimate the impacts generated by AERMET 16216 and AERMOD 16216r.

EPA released another AERMET/AERMOD update on April 24, 2018. They identified these updates as AERMET version 18081 (AERMET 18081) and AERMOD version 18081 (AERMOD 18081). The Department does not generally make applicants update their ambient demonstrations if there is a model update subsequent to the Department's approval of the modeling protocol. The Department nevertheless conducted a quick sensitivity analysis by rerunning the annual NO_2 project impact analysis for the worst-case year (2009) using AERMOD/AERMET 18081. The maximum annual impact is compared to the previous maximum impact in Table 2 of this report. The maximum impact from AERMET/AERMOD 18081 match the maximum impact from AERMET/AERMOD 15181 to the second decimal. This similarity in modeled impacts further confirms that AGDC's use of AERMET/AERMOD 15181 remains acceptable for the GTP PSD application.

Table 2. Department AERMOD Sensitivity Results ($\mu g/m^3$)

Maximum Annual NO_2 Conc. When Using AERMET/ AERMOD Version:	
15181	**18081**
2.61720	2.61614

5.3. Meteorological Data

AERMOD requires hourly meteorological data to estimate plume dispersion. A *minimum* of one-year of site-specific data, or five years of representative National Weather Service (NWS) data should be used, per Section 8.3 of the Guideline. When modeling with site-specific data, the Guideline states that up to five years should be used, when available, to account for year-to-year variation in meteorological conditions.

AGDC used five years of surface meteorological data collected by BPXA at their PBU A-Pad monitoring station. The data was collected from calendar years 2009 through 2013. AGDC also used concurrent upper air data from the nearest NWS upper air station, which is located in Utqiaġvik.[14] The use of A-Pad surface data with concurrent Utqiaġvik upper air data is the routinely used meteorological data set for modeling PBU stationary sources with AERMOD.[15]

5.3.1. Quality Assurance Review and Data Processing

Site-specific meteorological data must meet the PSD quality assurance (QA) requirements outlined in EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (EPA-454/R-99-005), per 18 AAC 50.215(a)(3). BPXA has routinely submitted annual A-Pad datasets for Department review over the past decade. The 2009 through 2013 data used by AGDC meets the QA requirements.

The Department has been posting the A-Pad/Utqiaġvik data in an AERMOD-ready format so that it can be readily used by PBU permit applicants.[16] A-Pad/Utqiaġvik data for calendar years 2007 – 2011 was available when AGDC prepared the NEPA analysis. The data had been processed by another permit applicant, using AERMET 15181. AGDC shifted the data period by two years for the NEPA analysis, but they used the same approach to process the two newer years of meteorological data.

AERMET requires the area surrounding the surface meteorological tower to be characterized with regard to the following three surface characteristics: noon-time albedo, Bowen ratio, and surface roughness length. The A-Pad data posted on the Department's web-site, as well as the additional data processed by AGDC, was processed using the Department approved surface parameters for tundra.[17] The approved surface parameters are repeated below in Table 3.

Table 3. Approved AERMET Surface Parameters for PBU A-Pad

Surface Parameter	Winter Value	Summer Value
Albedo	0.8	0.18
Bowen Ratio	1.5	0.80
Surface Roughness Length (m)	0.004	0.02

Table Note: Summer is defined as June through September, and winter is October through May, for purposes of processing A-Pad meteorological data with AERMET.

5.3.2. Low Wind Speed Adjustments

AERMET contains an option for adjusting the surface friction velocity (ADJ_u*) parameter. EPA developed this option to correct AERMOD's tendency to overpredict

14 Utqiaġvik was formerly known as Barrow.

15 The Department routinely accepts the use of A-Pad meteorological data for the modeling of PBU EUs with stacks that are less than 50 meters tall – which is the standard case. The Department has noted in various meetings with applicants that the modeling of taller stacks would warrant additional review and the possible need for tall tower meteorological data.

16 AERMOD ready meteorological dataset may be found at: http://dec.alaska.gov/air/air-permit/aeromod-met-data/

17 The Department has previously reported the approved surface parameters for tundra in numerous North Slope modeling reviews, as well as Section 2.6.4.2 of the Department's *Modeling Procedures Review Manual*.

impacts under stable, low wind conditions. AGDC did not use the ADJ_u* option for the GTP modeling analysis.[18] Some of the modeled results may therefore be overstated.

5.3.3. Tall Tower Sensitivity Analysis

The Department and the previous owner of the AK LNG Project discussed the adequacy of using A-Pad meteorological data for modeling GTP during a January 15, 2015 pre-application meeting. The Department noted that the A-Pad data is collected on a 10-meter (m) tower and that it would be acceptable as long as the GTP exhaust stacks are less than 50 m tall. However, the Department noted that additional justification would be needed if the stack heights exceed 50 m. The owner discussed the possibility of collecting tall tower meteorological data from a separate site to help address the concern.

5.3.3.1 Deadhorse Data Collection

The project owner subsequently decided to install a 60 m tall meteorological tower in Deadhorse in order to collect wind data at the 10 m, 30 m, and 60 m levels; along with the other meteorological parameters needed for modeling with AERMOD. The Department approved the proposed location for the tower on October 27, 2015, and the Quality Assurance Project Plan on July 15, 2016. The owner collected data from June 1, 2016 through May 31, 2017, and submitted the data for Department review on September 1, 2017. The Department found all parameters to be PSD quality, except for the 30 m vertical wind speed and vertical wind speed standard deviation values.[19] The Department notified AGDC of its findings on October 13, 2017.[20]

5.3.3.2 Analysis Criteria

The Department asked AGDC to provide a sensitivity analysis using the tall tower Deadhorse data in the Department's December 13, 2017 approval of the PSD modeling protocol. The Department asked for the analysis since some of the exhaust stacks will be more than 50 m tall (see Section 5.7.6 of this report). The Department stated that the analysis could be provided as part of the permit application. The Department further stated:

> *The sensitivity analysis should compare the modeled design concentrations when using just the 2-meter and 10-meter Deadhorse data (i.e., data that is commensurate with the A-Pad data) to the modeled design concentrations when using the data from all measurement levels. AGDC may limit the analysis to just the worst-case pollutants, rather than*

[18] The ADJ_u* option was considered as an alternative modeling technique when AGDC conducted their NEPA modeling analysis. Alternative modeling techniques require case-specific justification and Department/R10 approval under 18 AAC 50.215(c).

[19] The 30 m vertical wind speed data and vertical wind speed standard deviation data did not meet the QA requirements due to inadequate data capture.

[20] Email from Elizabeth Nakanishi (Department) to Kalb Stevenson (AGDC); *AK LNG GTP Meteorological data review findings 2016-2016*; October 13, 2017.

modeling all of the PSD-triggered pollutants, as long as AGDC assesses an annual impact, a 24-hour impact, and a 1-hour impact. The analysis should be conducted at the project impact level (i.e., just the GTP EUs) rather than cumulative impact level (i.e., GTP plus off-site EUs).

5.3.3.3 Analysis and Review

AGDC provided the tall tower sensitivity analysis as part of their May 1, 2018 submittal. They modeled the 1-hour NO_2, annual NO_2, 24-hour PM-2.5, and annual PM-2.5 project impacts for the two meteorological scenarios requested by the Department (i.e., just 2/10-m data, and data from all measurement levels). They used the version of AERMET and AERMOD that was current at the time: AERMET 16216 and AERMOD 16216r.

AGDC used a cursory approach for deriving the Deadhorse surface characteristics. They noted that a "more detailed analysis" would likely be required for regulatory applications, but that the "generalized approach is adequate for the intended purpose of this study." The Department found several errors in their write-up and was unable to replicate some of the derived surface parameters. However, the Department agrees that the values are "close enough" for purposes of this sensitivity analysis.

AGDC used the Plume Volume Molar Ratio (PVMRM) to estimate their ambient NO_2 impacts (see Section 5.10.1 of this report) – which is the same approach that they used in their NEPA analysis. However, they used a single O_3 value, rather than the hourly O_3 values used in their NEPA analysis. The Department reran the 1-hour and annual NO_2 analyses for the "all" meteorological data scenario using hourly O_3 data to see if this more detailed approach would significantly alter the results. It did not.

AGDC found essentially identical design concentrations between the "10-m" and "all" data scenarios. In some cases, the "10-m" scenario lead to marginally larger values than the "all" scenario. Based on this analysis, AGDC concluded: "*Given the model results are insensitive to the integration of tall-tower meteorological data demonstrates that use of lower single-level meteorological data is appropriate for modeling tall sources*."

AGDC included a number of source groups in the AERMOD runs, which was helpful in deciphering the results. It turns out that the maximum impacts are mostly caused by several EUs with relatively short stacks (i.e., less than 10 m tall). The Department further found from its review of the source group results and from its own runs of the two meteorological scenarios, that 10-m meteorological data may not be adequately representative if GTP had a different mix of EUs/stack heights. ***The Department therefore agrees that the use of 10-m meteorological data is acceptable for modeling the proposed GTP stationary source, but notes that this conclusion cannot be generally applied to all stationary sources with tall stacks***.

5.4. Coordinate System

Air quality models need to know the relative location of the EUs, structures (if applicable), and receptors, in order to properly estimate ambient pollutant concentrations. Therefore, applicants must use a consistent coordinate system in their analysis.

AGDC used the Universal Transverse Mercator (UTM) grid for their coordinate system. This is the most commonly used approach in AERMOD assessments. The UTM system divides the world into 60 zones, extending north-south, and each zone is 6 degrees wide in longitude. The modeled EUs, structures, and receptors are all located in UTM Zone 6. AGDC used the North American Datum of 1983 reference for each UTM coordinate.

5.5. Terrain

Terrain features can influence plume dispersion and the resulting ambient concentration. Digitized terrain elevation data is therefore generally included in a modeling analysis, unless the modeling domain is featureless.

AGDC did not need to obtain terrain elevation data since the North Slope coastal plain is fairly flat. They instead set all receptor elevations and hill heights to zero meters. They also used the pad elevations as the base heights for the exhaust stacks. According to AGDC, the GTP pad will be 1.83 m above the tundra. For the off-site EUs, AGDC used the same 1.52 m base height as previously used by BPXA in their modeling of CCP/CGF.

5.6. EU Inventory

The modeled EU inventory for GTP is described below, along with the off-site inventory that AGDC used in the cumulative impact analyses. The secondary emissions required in a cumulative impact analysis are also discussed.

5.6.1. GTP EU Inventory

AGDC modeled the combustion turbines, heaters, reciprocating engines, and flares described throughout their permit application, including Table 4-1 of the GTP Modeling Report. The EU locations are illustrated in Figures 5-5 and 5-6 of the GTP Modeling Report. AGDC characterized all of the EUs as point sources (see related discussion in Section 5.7 of this report).

AGDC assumed all EUs are concurrently operating, except as noted below. AGDC assumed that:

- Only two of the three Building Heat Medium Heaters (**EUs 31 – 33**) are operating at any time; and
- Only two of the three Operations Camp Heaters (**EUs 36 – 38**) are operating at any time.

The Department is imposing the non-concurrent operating assumption for **EUs 31 – 33** and **36 – 38** as an ambient air condition.

5.6.2. Off-site EU Inventory

As previously noted in Section 5.1 of this report, AGDC included the CCP/CGF stationary source in their cumulative impact analyses. The modeled EUs are listed in Appendix A of the GTP Modeling Report. The off-site EU inventory used by AGDC for the *AAAQS* analyses accurately incorporates the gas-fired combustion turbines, gas-fired heaters, diesel-fired equipment, and flares listed in the current Title V permits for CCP and CGF.[21]

AGDC used the installation/modification date listed in the CCP/CGF operating permits to determine which off-site EUs are increment consuming.[22] The off-site inventory therefore varied by pollutant since the baseline date is pollutant-specific (see the related discussion in Section 2.3 of this report). The Department agrees with the off-site inventories selected for the NO_2, PM-10, and PM-2.5 increment analyses. However, the Department partially disagrees with the off-site inventory selected for the SO_2 increment analyses.

CCP/CGF underwent PSD review for SO_2 in 2008-2009 to accommodate an increase in the fuel gas hydrogen sulfide level. The resulting increase in SO_2 emissions, including the increases from the baseline EUs, is increment consuming. The Department therefore expanded the off-site SO_2 inventory so that it matches the CCP/CGF EU inventory used by BPXA in their SO_2 increment demonstration.[23] The Department then reran the 3-hour and 24-hour SO_2 increment analyses for all five meteorological data years.[24, 25, 26] The gas-fired CCP/CGF EUs that the Department added to the SO_2 increment analyses are listed below in Table 4. The maximum SO_2 impacts increased by various margins, but they still demonstrate compliance with the 3-hour and 24-hour Class II increments. The Department's SO_2 modeling results are reported in Section 6 of this report.

[21] The off-site EU inventories listed in Appendix A of the GTP Modeling Report do not include the BS&B TEG Reboilers at CCP (EUs 21 and 22: Model IDs 703 and 704). These EUs have been decommissioned, but they are still listed in Operating Permit 166TVP01. AGDC included them in the AAAQS analyses.

[22] AGDC summarized the installation/modification date and increment consuming status of the off-site EUs in Appendix A of the GTP Modeling Report.

[23] The Department reported its findings regarding BPXA's SO_2 modeling analysis in the September 2009 memorandum, *Review of BPXA's Ambient SO_2 Assessment for CGF/CCP – Revised*. The memorandum may be found in Exhibit B of the Technical Analysis Report for Construction Permits AQ0166CPT04 and AQ0270CPT04.

[24] The Department did not need to conduct an annual SO_2 increment analysis since the GTP project impacts are less than the annual SO_2 SIL. See Section 6 of this report for details.

[25] The Department used AERMOD/AERMET 18081 for the revised SO_2 increment analyses.

[26] The Department also assumed continuous GTP flaring, as discussed in Section 5.7.3 of this report.

Table 4. CCP/CGF EUs Added to the SO_2 Increment Analyses

Facility	EU	Model ID	Description
CCP	17	814	Broach Glycol Heater
	18	815	Broach Glycol Heater
	19	702	Eclipse Glycol Heater
	20	701	Eclipse Glycol Heater
	26 - 29	819 - 825	Flares
CGF	*None – AGDC already included all gas-fired EUs*		

Table Note: The Department did not add the two BS&B TEG Reboilers at CCP (EUs 21 and 22) since they have been decommissioned. The actual SO_2 emissions for these EUs is 0 grams per second.

5.6.3. Secondary Emissions Inventory

PSD applicants must include "secondary emissions" in their ambient demonstration, per 40 CFR 52.21(k)(1). EPA defines the term in 40 CFR 52.21(b)(18) as, "*emissions which would occur as a result of the construction or operation of a major stationary source… but do not come from the major stationary source…*" However, secondary emissions do not include "*any emissions which come directly from a mobile source*." Subsequent EPA guidance further clarifies that the definition in 40 CFR 52.21(b)(18) "*sets out four tests to be used in determining whether such emissions are to be included in air quality impact assessments for PSD purposes: the emissions must be specific, well defined, quantifiable, and impact the same general area*." [27]

The only secondary emissions that would occur due to the construction and operation of the GTP are the construction emissions that would occur within the local area. The emissions that would occur due to the remaining aspects of the AK LNG Project, including the construction/operation of the Pipeline Stations and Liquefaction Plant, are not secondary emissions for purposes of the GTP PSD review since they will not occur in the same general area as the GTP emissions.[28]

AGDC provided a general discussion regarding their construction emissions in Section 4.1.3 of the GTP Modeling Report, and a more detailed discussion in their May 1, 2018 submittal. AGDC stated the GTP construction phase would last approximately 8 years. However, they noted that the majority of GTP would consist of modules constructed off-site and transported to the site via seagoing barge. This

[27] EPA letter from Edward F. Tuerk (Acting Assistant Administrator for Air, Noise and Radiation) to Allyn M. Davis (Director, Air and Hazardous Materials Division); *PSD Evaluation of Secondary Emissions for Houston Lighting and Power*; March 17, 1981.

[28] The Liquefaction Plant, and each of the Pipeline Stations, are separate stationary sources for air quality permitting purposes. The ambient impacts associated with each of those stationary sources will be assessed, as warranted, under the permit requirements for that stationary source.

approach would generally lead to secondary emissions that are less than the operational emissions used in the modeling analysis. AGDC further noted that the various construction activities/emissions would change during the 8-year period. They verbally clarified that even the temporary construction camp would be moving between various locations until the permanent worker housing camp becomes operational.[29]

Developing the parameters needed to correctly characterize and simulate constantly changing construction emissions, especially fugitive dust emissions, is challenging. In some cases, the resulting concentrations are questionable, if not overly conservative. The Department further notes that the modeling results generally lead to: fugitive dust control plans (to minimize the fugitive dust impacts); and/or requirements to install vertical, uncapped exhaust stacks on the camp engines (to reduce the impacts from the combustion sources – see Sections 5.7.7 and 5.8.2 of this report). The Department therefore decided to impose the typical endpoint (i.e., ambient air conditions) rather than requiring AGDC to develop the details needed to model the construction phase emissions.

The Department imposed the following ambient air conditions for the GTP construction phase:

- Fugitive dust control;
- A requirement to construct and maintain vertical, uncapped stacks on all temporary camp engines; and
- A requirement to install and operate PM-10 and PM-2.5 ambient air monitoring stations throughout the construction phase.

The ambient air monitoring provision includes an action plan that requires evaluation and possible further control of the dust-generating activities at set concentration levels.

5.7. GTP Emission Rates and Stack Parameters

The Department generally found the modeled emission rates to be consistent with the emissions information provided throughout their application. The modeled stack parameters are likewise generally reasonable. The exceptions, or items that otherwise warrant additional comment, are discussed below.

AGDC used the same EU inventory, emission rates, and stack parameters in the Class II increment analyses as used in the AAAQS demonstrations. This is an appropriate approach since the GTP EUs are fully increment consuming (see the related discussion in Section 2.3 of this report).

5.7.1. Turbines

Each of the compression turbines (**EUs 1 – 12**) will have two exhaust stacks: one with a Waste Heat Recovery Unit (WHRU) that includes a supplemental firing system

[29] Jim Pfeiffer and Kalb Stevenson of AGDC described the portable nature of the temporary construction camp during a June 7, 2018 teleconference with Aaron Simpson, Dave Jones, and Alan Schuler (Department).

(**EUs 13 – 24**); and the other as a WHRU bypass. Both stacks would be designed to accept the full exhaust stream from the turbine. The WHRU stack would have greater emissions than the bypass stack (due to the emissions from the supplemental firing system), which in turn could lead to larger ambient impacts. However, the additional exhaust from the supplemental firing system could also lead to decreased impacts due to the increase in plume buoyancy. AGDC resolved these conflicting factors by using a simplified, but conservative, modeling approach. They used the WHRU stacks for the modeling analysis and included the supplemental firing emissions, but they did not include the additional exhaust flow rate. AGDC also used the WHRU exit temperature (410°F) rather than the more buoyant bypass temperature (1,650°F).

AGDC stated the Combustion Turbine Generators (**EUs 25 – 30**) will operate between 60 percent and 100 percent load. They conservatively addressed this variation by using the worst-case emissions and stack conditions, regardless of load, in their modeling analysis: i.e., the full-load emission rate, and 60-percent load exhaust conditions.

AGDC increased the modeled emissions rate for all turbines by 10 percent in the 1-hour NO_2 and 1-hour SO_2 AAAQS demonstrations. They stated the 10 percent "safety factor" accounts for short-term load variations.

5.7.2. Buyback Gas Bath Heaters

AGDC stated the two Buyback Gas Bath Heaters (**EUs 34** and **35**) would typically operate in a standby low-load mode, with infrequent instances of full-load operation. They characterized this operating scenario in the modeling analysis by representing each condition with an exhaust stack: one stack with an exhaust flow that represents a 10 percent load condition; and the other stack with an exhaust flow that represents a full-load condition. They also used emissions that reflect continuous, year-round operation at 10 percent load for the low-load stack. For the full-load stack, AGDC assumed the full-load condition occurs for only 500 hours per year (hr/yr) for the annual, and 1-hour NO_2/SO_2 assessments. They used the maximum hourly emission rate for the remaining short-term AAAQS and increments.[30]

The Department typically imposes a part-year operating assumption as a permit restriction. However, creating a viable condition that varies the annual cap by load is both unusual and challenging. The Department therefore conducted two sensitivity analyses to determine whether a 500 hr/yr restriction is needed to protect the AAAQS/increments.

The Department reran the annual NO_2 increment analysis for the worst-case year (2010), and the 1-hour NO_2 AAAQS analysis.[31] The Department assumed the Buyback Heaters are continuously operating year-round under full-load, as well as 10 percent load. This represents more emissions than what could actually occur, but it provides for

[30] "Short-term" refers to less than annual: i.e., the 1-hour, 3-hour, 8-hour, and 24-hour averaging periods.
[31] The Department used AERMOD/AERMET 18081 in the Buyback Heater sensitivity analyses.

a conservative sensitivity analysis. The Department also corrected a NO_2-to-NOx in-stack ratio error that is discussed in Section 5.10.1.2 of this report. The maximum annual impact increased from the 11.3 $\mu g/m^3$ value discussed in Section 5.10.1.2 of this report to 11.4 $\mu g/m^3$. This is an inconsequential change, especially given the wide margin of compliance with the 25 $\mu g/m^3$ Class II NO_2 increment. The high eighth-high (h8h) 1-hour NO_2 impact increased by only 0.003 $\mu g/m^3$, which is also inconsequential. Similar findings are expected for the other pollutants. The sensitivity analyses show that the full load operation does not need to be restricted in order to protect the AAAQS and increments. The Department is reporting the 11.4 $\mu g/m^3$ value as the annual NO_2 increment consumption in Section 6 of this report.

5.7.3. Flares

GTP will have two sets of emergency flares: one operational and one spare. Each set includes a High Pressure (HP) hydrocarbon flare, a Low Pressure (LP) hydrocarbon flare, a HP carbon dioxide (CO_2) flare, and a LP CO_2 flare. Pilot and purge gas would be continuously combusted at each of the eight flares during normal operations. AGDC therefore included the pilot/purge operation of all eight flares in their modeling analysis. However, they also included the flaring events that could occasionally occur at the four operational flares. AGDC used the rated capacity of the flares to calculate the emissions and plume characteristics of the flaring event. Including flaring events and pilot/purge conditions as if they are simultaneously occurring makes that part of their modeling analysis conservative since these scenarios are mutually exclusive.

Flares can typically be treated as point sources, but they require special handling since the emissions are generated outside of the flare stack. Most applicants use the approach described in Section 2.1.2 of EPA's AERSCREEN User's Guide, whereby the exhaust temperature is set to 1273K, the exit velocity is set to 20 meters per second (m/s), the stack height is the physical height plus flame length, and the stack diameter is based on the heat release rate. AGDC used the AERSCREEN approach for characterizing the pilot/purge conditions as well as the flaring events.

AGDC assumed the flaring events would occur for 500 hr/yr for purposes of modeling the annual impacts as well as the 1-hour NO_2 and 1-hour SO_2 impacts. However, they assumed the flaring events would occur for only 30 minutes per day (min/day) for all other pollutants/averaging periods. Neither assumption substantially affects the modeled results or conclusions for the reasons described below.

The maximum impact from flaring events generally occurs well beyond the area of the total maximum impact from a North Slope stationary source. This trend holds especially true for GTP due to the tall height of the flare stacks (see Section 5.7.6 of this report) and extremely buoyant nature of the flaring events. The effective stack height of the flaring events range from 107 m for the HP Byproduct (CO_2) Flares to 256 m for the HP Hydrocarbon Flares. These heights, along with the additional plume rise from the high temperature release, lead to relatively large travel distances prior to plume touchdown. For example, the high first-high (h1h) 24-hour PM-2.5 impact from just the GTP flaring event occurs 15 km from GTP.[32] This is substantially further than the h1h project impact, which occurs along the pad edge – i.e., in the immediate near-field.

Increased travel distance allows for increased dispersion. The resulting impact from flaring therefore tends to be substantially smaller than the maximum total impact. For example, the h1h 24-hour PM-2.5 impact from the 30 min/day flaring event is only 0.033 $\mu g/m^3$ whereas the h1h project impact is 3.88 $\mu g/m^3$. The maximum flare impact increases to 1.6 $\mu g/m^3$ if one conservatively assumes continuous flaring, but even this value is less than half of the project impact. The Department further notes that the GTP flare event impacts are inconsequential within the immediate near-field. Similar findings would occur for the other averaging periods due to the general principals discussed above. Therefore, there is no need to incorporate the 500 hr/yr or 30 min/day assumptions as permit conditions.

In spite of the above findings, the Department assumed continuous flaring events when it remodeled the 3-hour and 24-hour AAAQS/increment impacts for the various reasons described in this report. The Department used this very conservative approach to further show that the flaring events do not need operating restrictions.

5.7.4. Reciprocating Engines

AGDC assumed the six reciprocating engines (**EUs 39 – 44**) each operate for only 500 hr/yr. AGDC used this assumption to derive the emission rates used in the annual AAAQS/increment demonstrations, as well as the 1-hour NO_2 and 1-hour SO_2 AAAQS demonstrations. The annual emission rate may be used to characterize intermittently operated EUs in the 1-hour NO_2 and 1-hour SO_2 AAAQS demonstrations per EPA policy.[33] The Department is imposing the 500 hr/yr assumption as an ambient condition to protect the annual AAAQS/increments, as well as the 1-hour NO_2 and 1-hour SO_2 AAAQS.

5.7.5. Sulfur Compound Emissions

SO_2 emissions are directly related to the sulfur content of the fuel. AGDC assumed their diesel-fired EUs use fuel with a sulfur content of 15 parts per million by weight (ppmw). They assumed their gas-fired EUs use treated gas with a total sulfur content of 96 parts per million by volume (ppmv). The Department is imposing these assumptions as permit conditions to protect the SO_2 AAAQS/increments.

[32] The Department conducted a 24-hour PM-2.5 analysis of just the GTP flaring events to determine the range and magnitude of the maximum impact. The Department initially used the cumulative impact receptor grid described in Section 5.14 of this report, but the maximum impact occurred at the outer range of that receptor grid. The Department therefore extended the grid in the predominate downwind direction in order to find the true range of the maximum impact.

[33] EPA Memorandum from Tyler Fox to Regional Air Division Directors, *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard;* March 1, 2011.

5.7.6. Stack Heights

Most of the GTP exhaust stacks are substantially taller than what is common for a North Slope stationary source. The heights used in the modeling analysis comply with the stack height requirements listed in 40 CFR 52.21(h) and 18 AAC 50.045(e) – (f), but they are nevertheless noteworthy. For example, AGDC assumed the turbine stacks are 73 m tall, which is twice the height of the CCP/CGF turbine stacks. The height is also twice the height of the host buildings, which is likely intentional for purposes of minimizing downwash (see the related discussion in Section 5.11 of this report).

AGDC assumed the building heater stacks are nearly 71 m tall, and that the black start generator stack is 35 m tall. These are unusually tall heights for North Slope EUs, especially considering that the EUs are not in or adjacent to a building. The camp heater stacks are also taller than expected considering that they too do not have a host building.

The physical height of the flare stacks will be 67.056 m, which is taller than the typical height of a North Slope flare. However, AGDC used 65 m as the physical height in their modeling analysis, per the Good Engineering Practice (GEP) requirement in 40 CFR 52.21(h)(1)(i) and 18 AAC 50.045(f)(1).

The Department is imposing the assumed stack heights for the EUs described above as a minimum height requirement to protect the AAAQS and increments. The modeled stack heights are reiterated below in Table 5. The assumed stack heights for the remaining EUs are either within expectations, or they have designs that would maximize downwash. The Department is imposing the GEP height for the flares rather than the actual physical height, since GEP establishes the upper bound of what may be used in the ambient demonstration.

Table 5. Minimum Stack Height Requirements

EU	Model ID	Description	Min. Stack Height (m)
1 - 6	1A – 3B	Treated Gas Compressors	73.15
7 - 12	4A – 6B	Byproduct (CO_2) Compressors	73.15
25 - 30	7A_1A – 7A_3B	Combustion Turbine Generators	73.15
31 - 33	14_1 – 14_3	Building Heat Medium Heaters	70.71
36 - 38	CAMPHT1 – CAMPHT3	Operations Camp Heaters	9.75
39	9_1	Black Start Generator	35.05
45 - 52	10E – 13W	Flares: Hydrocarbon and Byproduct (CO_2)	65.00

Table Note: For EUs 1 – 12, the stack height requirement applies to both the WHRU bypass stack and the WHRU stack (i.e., EUs 13 – 24).

5.7.7. Horizontal/Capped Stacks

Capped stacks or horizontal releases generally lead to higher impacts in the immediate near-field than what would occur from uncapped, vertical releases. The presence of non-vertical stacks or stacks with rain caps therefore requires special handling in an AERMOD analysis (see the related discussion in Section 5.8.2 of this report).

AGDC characterized all of the GTP EUs as having uncapped, vertical releases. This is a typical stack design for combustion turbines. However, heaters can have rain caps and reciprocating engines can have horizontal releases. Since the impacts from horizontal or capped stacks are typically greater than the impacts from stacks with vertical, uncapped discharges, the Department is imposing AGDC's vertical, uncapped assumption for the heaters and reciprocating engines as an ambient air condition.

5.8. Off-Site Emissions and Stack Parameters

AGDC used the current CCP/CGF operating permits and past modeling analyses to develop the off-site emission rates and stack parameters for the cumulative impact analyses. They used the potential to emit (PTE) emission rates, rather than the actual emission rates allowed under the Guideline, in the annual assessments.[34] The use of PTE rather than actual emissions makes the annual analyses conservative. The modeled short-term emission rates, along with the characterization of several horizontal stacks, warrants discussion.

5.8.1. CCP/CGF Short-Term Emission Rates

The gas-fired CCP/CGF EUs are authorized to continuously operate on a year-round bases. AGDC therefore characterized these EUs with unrestricted emissions in the ambient demonstrations with 1-hour, 3-hour, or 24-hour averaging periods. This approach is consistent with Table 8-2 of the 2005 Guideline.

In contrast to the gas-fired EUs, the diesel-fired EUs at CCP/CGF are intermittently operated emergency generators and fire water pumps with operating limits ranging from 200 to 295 hr/yr. The annual emission rates may therefore be used to characterize these EUs in the 1-hour NO_2 and 1-hour SO_2 AAAQS demonstrations per EPA guidance (see Section 5.7.4 of this report). AGDC appropriately used this approach in the 1-hour NO_2 and 1-hour SO_2 AAAQS demonstrations.

AGDC also used the annual emission rates for modeling the other short-term AAAQS/increments. The Department questions this approach. EPA's intermittent emissions guidance is limited to the 1-hour NO_2 and 1-hour SO_2 "probabilistic" ambient air quality standards. The Department is unaware of any EPA guidance which states that the annual emission rate may be used for the 24-hour PM-2.5 probabilistic ambient air quality standard, or the short-term "deterministic" AAAQS/increments.

34 Appendix A of the GTP Modeling Report states AGDC used the actual emissions for the Class II increment analyses. However, the modeling files show that they actually used the PTE rates.

The Department likewise does not have a written policy for characterizing intermittently operated EUs within the off-site EU inventory. This lack of written policy made the Department's review challenging. The Department understands that AGDC did not want to use an overly conservative characterization of these highly restricted EUs. However, using the annual emissions for the 3-hour/24-hour AAAQS/increment demonstrations may understate what likely happens during those averaging periods. The 200 hr/yr limit equates to 33 min/day, and the 295 hr/yr limit equates to 49 min/day. The Department suspects that BPXA operates these EUs for longer periods than that during their periodic reliability checks.

The Department reviewed the Triennial Emission Inventory provided by AGDC for the nearest off-site facility (CGF). BPXA operated emergency EUs up to 61 hours in the reporting year. This averages to 5.1 hours per month, which could be conservatively rounded up to 6 hours per month. This means the reliability check would occur for up to 6 hours per day (hrs/day) if BPXA conducted monthly checks. The 6 hr/day assumption seems to provide a better approach for characterizing the intermittently operated off-site EUs in the 3-hour and 24-hour AAAQS/increment demonstrations than the 33 to 49 min/day assumption. The Department therefore reran the 3-hour and 24-hour AAAQS/increment demonstrations using the 6 hrs/day assumption.[35]

The Department also made one other change to the off-site emission rates. AGDC used a total particulate matter (PM) emissions factor for most of the diesel-fired CCP/CGF EUs, rather than the substantially smaller PM-10 emissions factor. This approach seemed overly conservative, especially when used in conjunction with the 6 hr/day operating assumption. The Department therefore used the PM-10 emissions factor from Table 3.4-2 of EPA's *Compilation of Air Emissions Emission Factors* to recalculate the PM-10/PM-2.5 emission rates for all but one of the CCP/CGF reciprocating engines rated at greater than 600 horsepower. The exception regards one of the three GM Emergency Generators at CGF (EU 15), which has a short-term PM emissions rate that was determined through a Best Available Control Technology (BACT) analysis. AGDC appropriately used the BACT emissions rate to calculate the PM-10/PM-2.5 emissions for this EU. The Department's modeling results are provided in Section 6 of this report.

5.8.2. Characterization of Off-site Horizontal Stacks

As noted in Section 5.7.7 (**Horizontal/Capped Stacks**) of this report, the presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis. While all of the GTP EUs have uncapped, vertical releases, two of the off-site EUs have horizontal releases.[36]

[35] The Department did not need to rerun the 24-hour PM-2.5 increment analysis since the CCP/CGF EUs do not consume PM-2.5 increment.

[36] The two off-site EUs with horizontal stacks are the Solar Centaur Standby Turbine at CCP (Model ID 816) and the fire water pump at CGF (Model ID 1122).

EPA describes the proper approach for characterizing capped and horizontal stacks in their *AERMOD Implementation Guide*.[37] EPA has also developed an option in AERMOD that will revise the release parameters according to their guidance for any stack identified as horizontal (using the POINTHOR keyword) or capped (using the POINTCAP keyword).

AGDC used the POINTHOR option to characterize the two off-site EUs with horizontal stacks. The option is an approved modeling technique under the 2016 version of the Guideline, but it is considered as an alternative technique under the 2005 version that the Department used for its review (see Section 2.4.3 of this report). AGDC's use of the POINTHOR option therefore requires case-specific approval under 18 AAC 50.215(c).

5.8.2.1 Technical Justification

18 AAC 50.215(c)(1) requires a demonstration that the alternative approach is more appropriate than the preferred air quality model. EPA provided the required demonstration when they promulgated the 2016 version of the Guideline. A summary of this demonstration may be found in the January 17, 2017 Federal Register notice of the 2016 Guideline (see 82 FR 5182).

5.8.2.2 EPA and Department Approval

18 AAC 50.215(c)(2) requires approval of an alternative modeling technique from the EPA Regional Administrator and the Commissioner's designee. The Commissioner delegated the responsibility for approving alternative modeling methods to the Air Permits Program (APP) Manager on June 3, 2008.

AGDC noted their desire to use the POINTHOR option for the cumulative impact analysis in their PSD modeling protocol. The APP Manager approved AGDC's request on October 24, 2017. R10 approved the request on December 12, 2017.

5.8.2.3 Public Comment

In addition to complying with the Department's modeling requirements in 18 AAC 50.215(c), PSD applicants must also comply with the PSD modeling requirements in 40 CFR 52.21(l). 40 CFR 52.21(l)(2) says the use of a non-Guideline modeling technique, "*must be subject to notice and opportunity for public comment*." Therefore, the Department is soliciting public comment regarding AGDC's use of the POINTHOR algorithm in the public notice of the preliminary construction permit.

5.9. Shoreline Fumigation Analysis

Section 7.2.8 of the Guideline describes various complex wind scenarios that may need to be addressed in an air quality modeling analysis. One of those scenarios, shoreline fumigation, warranted assessment in the GTP analysis.

[37] *AERMOD Implementation Guide* (EPA-454/B-18-003); April 2018.

Fumigation "*occurs when a plume that was originally emitted into a stable layer is mixed rapidly to ground-level when unstable air below the plume reaches plume level*." [38] The phenomena can cause high ground-level concentrations. In coastal areas, fumigation can occur when a plume that is emitted from a tall stack interacts with the "*thermal internal boundary layer*" (TIBL) at some downwind distance. The phenomena is illustrated in Figure 5-7 of Attachment 5 of the permit application.

GTP will be located approximately 2 km from the Beaufort Sea coast-line, and the tallest exhaust stacks will be 73 m high. This proximity and stack height is what warrants the shoreline fumigation analysis. AGDC correctly noted that AERMOD does not have the ability to evaluate fumigation impacts. However, AERSCREEN will calculate shoreline fumigation for EUs located within 3 km of a coastline.

AGDC ran AERSCREEN for the EUs with the tallest stacks – i.e., the turbines. AERSCREEN found that the plume heights are below the TIBL height. Therefore, shoreline fumigation would not occur from the turbine emissions. AGDC concluded that shoreline fumigation likewise would <u>not</u> occur from the other EUs.

5.10. Pollutant Specific Considerations

The following pollutants warrant additional discussion.

5.10.1. Ambient NO_2 Modeling

The NOx emissions from combustion sources are partly nitric oxide (NO) and partly NO_2. After the combustion gas exits the stack, additional NO_2 can be created due to atmospheric reactions. Section 5.2.4 of the Guideline describes a tiered approach for estimating the resulting annual average NO_2 concentration, ranging from the simplest but very conservative assumption that 100 percent of the NO is converted to NO_2, to other more complex methods. These approaches are also generally applicable in modeling the 1-hour NO_2 impacts.

AGDC used PVMRM[39] to estimate their ambient NO_2 concentrations. PVMRM is an EPA-approved modeling technique under the 2016 version of the Guideline, but it is considered as an alternative technique under the 2005 version (see Section 2.4.3 of this report). PVMRM therefore requires case-specific approval under 18 AAC 50.215(c). Applicants must also provide the assumed NO_2-to-NOx in-stack ratio (ISR) for each NOx-emitting EU, along with the ambient O_3 data used by PVMRM to estimate the NO to NO_2 conversion. Each of these aspects is further discussed below.

[38] Section 4.5.3 of EPA's *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised* (EPA-454/R-92-019)

[39] The PVMRM algorithm in AERMOD 16216r and AERMOD 18081 was designated as "PVMRM2" in AERMOD 15181.

5.10.1.1 Procedural Requirements

As previously discussed in Section 5.8.2.1 of this report, 18 AAC 50.215(c)(1) requires a demonstration that the alternative approach is more appropriate than the preferred air quality model. EPA provided the required demonstration when they promulgated the 2016 version of the Guideline (see 82 FR 5182).

18 AAC 50.215(c)(2) requires R10 and Department approval of the alternative modeling technique. The APP Manager approved AGDC's request to use PVMRM on October 24, 2017, and R10 approved the request on December 12, 2017. The Department is soliciting public comment regarding the use of PVMRM in the public notice for the preliminary permit, as required under 40 CFR 52.21(l)(2).

5.10.1.2 NO_2-to-NOx In-Stack Ratio

The assumed ISR is a variable that must be set for each NOx-emitting EU. Source-specific data should be used to define this ratio when available. When source-specific data is not available, an ISR of 0.5 may be used per EPA guidance.[33] EPA and the Department have data that applicants frequently use for finding representative ISRs. EPA's data may be found on their *Support Center of Regulatory Atmospheric Modeling* (SCRAM) web-site [40] and the Department's data may be found on its modeling web-site.[41] AGDC used the ISRs shown in Table 6.

Table 6. ISRs Used in the GTP Modeling Analysis

Stationary Source	EU Description/Category	ISR
GTP	Treated Gas Compressor Turbines	0.4
	Byproduct (CO_2) Compressor Turbines	0.2
	Power Generation Turbines	0.4
	Gas-fired Heaters	0.5
	Diesel-fired Reciprocating Engines	0.5
	Flares	0.5
CCP/CGF	Uncontrolled Turbines	0.1
	Turbines w/LHE Liners [a]	0.4
	Gas-fired Heaters	0.1
	Diesel-fired Reciprocating Engines	0.1
	Flares	0.5

Table Note a: LHE = Lean Head End. LHE Combustion Liners are designed to reduce NOx formation during the combustion process.

[40] The ISR database on SCRAM may be found at: https://www3.epa.gov/ttn/scram/no2_isr_database.htm.
[41] The Department's ISR database may be found at: http://dec.alaska.gov/air/air-permit/dispersion-modeling/.

AGDC did not include an ISR for one of the CGF emergency generators (EU 15; Model ID 1121) in the annual NO_2 increment analysis. It appears to be an inadvertent oversight since they did include the ISR for this EU in the 1-hour and annual NO_2 AAAQS demonstrations. ADEC corrected the oversight and reran the annual NO_2 increment analysis.[42] The maximum annual NO_2 impact increased from 6.6 µg/m^3 to 11.3 µg/m^3. [43] The Department is reporting the revised value, as subsequently modified by the Department's Buyback Gas Bath Heater sensitivity analyses, in Section 6 of this report.

The 0.5 value used for GTP diesel-fired reciprocating engines is conservative since most North Slope applicants justify and use values ranging from 0.1 to 0.2. The 0.1 value used for the CCP/CGF engines is a commonly used value for existing diesel-fired engines based on the source test data in the Department and EPA databases.

The 0.5 values used for the GTP heaters is likewise more conservative than what most North Slope applicants use. The 0.1 value used for the CCP/CGF heaters is consistent with commonly used values.

The 0.4 ISR for the Treated Gas Compression turbines and the Power Generation turbines is an acceptable value for gas-fired turbines with dry low NOx combustors. AGDC's 0.2 ISR for the Byproduct (CO_2) Compression turbines on the other hand lacked justification. The Department therefore conducted a sensitivity analysis using a 0.5 ISR for *all* GTP turbines. The Department reran the 1-hour NO_2 cumulative impact analysis, as well as the annual NO_2 increment analysis for the worst-case year (2010). The h8h 1-hour NO_2 impact increased by only 0.0002 percent (0.00031 µg/m^3), which is inconsequential. The maximum annual NO_2 increment impact increased by only 0.09 percent (0.00983 µg/m^3), which is also inconsequential.[44] The Department therefore accepts the ISRs for the GTP turbines since the maximum impacts are insensitive to this parameter. The ISRs for the CCP/CGF turbines are based on source tests of representative EUs at CCP/CGF.

5.10.1.3 Ambient O_3 Data

PVMRM requires ambient O_3 data to determine how much of the NO is converted to NO_2. AGDC used an hourly O_3 dataset that they compiled from five years of ambient data measured by BPXA at their A-Pad monitoring station. BPXA

[42] The Department made the ISR correction prior to conducting the Buyback Heater sensitivity analysis discussed in Section 5.7.2 of this report. However, the Department kept the ISR correction in all subsequent NO_2 sensitivity analyses.

[43] AERMOD 15181 inappropriately assigned an ISR of -9 for the missing EU, which led to an underestimated annual NO_2 impact. ISRs can only range from 0 to 1, so it's unclear why AERMOD assigned a negative value. EPA corrected this error in AERMOD 16216r. Missing ISRs now lead to a fatal error in the model execution.

[44] The Department used AERMOD/AERMET 18081 for the ISR sensitivity analysis. Therefore, some of the reported variation may be due to the change in model version rather than the change in ISR value. Either way, the variation is inconsequential.

collected the data from 2009 through 2013. The Department found the O_3 data to be PSD-quality in its review of BPXA's annual data reports.

AGDC developed a composite O_3 dataset for the NO_2 modeling analysis rather than using concurrent O_3 data. They did so by taking the maximum O_3 concentration for a given day and hour from the five years of data. They used the seasonal maximum value for the given hour if any year had a missing or invalid concentration for that Julian day and hour.

AGDC's use and processing of the hourly A-Pad O_3 data is reasonable and appropriate. The A-Pad data generally represents the ambient O_3 concentration that would be present at GTP. However, the Department is aware of periodic NOx scavenging events at A-Pad. This can lead to underestimated NO_2 concentrations in a modeling analysis, since small O_3 values can lead to less NO to NO_2 conversion than large O_3 values. Conservatively combining multiple years of O_3 measurements into a composite dataset counters the effect of periodic scavenging and helps to ensure that the resulting NO_2 concentrations are not underestimated. It's an approach that has been commonly used by North Slope applicants for the past decade. The Department continues to accept this approach, along with the composite dataset used by AGDC for the GTP modeling analysis.

5.10.2. PM-2.5

PM-2.5 is either directly emitted from a source or formed through chemical reactions in the atmosphere (secondary formation) from other pollutants (NOx and SO_2).[45] AERMOD is an acceptable model for performing near-field analyses of the direct emissions, but EPA has not developed a near-field model that includes the necessary chemistry algorithms for estimating the secondary impacts. They instead issued guidance as to how secondary formation could be accounted for under the 2005 version of the Guideline.[46]

EPA noted that the maximum direct impacts and the maximum secondary impacts from a stationary source "*…are not likely well-correlated in time or space*", i.e., they will likely occur in different locations and at different times. This difference occurs because secondary PM-2.5 formation is a complex photochemical reaction that requires a mix of precursor pollutants in sufficient quantities for significant formation to occur. As such, it is highly unlikely that there is sufficient time for the reaction to substantively occur within the immediate near-field, which is where the maximum direct impacts from the GTP EUs occur.

EPA further stated that representative ambient monitoring data could be used in the ambient standard demonstration to address the secondary formation that occurs from existing sources. AGDC met this objective by using the CCP PM-2.5 data as the

45 The NOx and SO_2 emissions are also referred as "precursor emissions" in a PM-2.5 assessment.
46 *Guidance for $PM_{2.5}$ Permit Modeling* (EPA-454/B-14-001); May 2014.

background concentration in their 24-hour PM-2.5 AAAQS analysis (see Section 5.15 of this report).

AGDC noted in Attachment 3 of their permit application that the ambient 24-hour and annual PM-2.5 concentrations measured at a number of North Slope monitoring stations are well below the AAAQS. They further observed that the values "*are all well below the standards even with the presence of large regional sources of direct and precursor emissions*." They provided the regional NOx emissions, as reported in the 2011 National Emissions Inventory (NEI), to support this observation. Their presentation is further evidence that the precursor emissions should not cause or contribute to a violation of the PM-2.5 AAAQS.

The portion of the existing secondary PM-2.5 concentration that is increment consuming is probably negligible. The major source baseline date for PM-2.5 is October 20, 2010. The minor source baseline date within the Northern Alaska Intrastate Air Quality Control Region is November 2, 2012. Most of the regional precursor emissions were authorized long before these dates. Therefore, the change in regional precursor emissions subsequent to these dates is likely inconsequential with respect to secondary formation.

5.11. Downwash

Downwash refers to the situation where local structures influence the plume from an exhaust stack. Downwash can occur when a stack height is less than GEP, which is defined in 18 AAC 50.990(42). It is a consideration when there are receptors relatively near the applicant's structures and exhaust stacks.

EPA developed the "Building Profile Input Program – PRIME" (BPIPPRM) program to determine which stacks could be influenced by nearby structures and to generate the cross-sectional profiles needed by AERMOD to determine the resulting downwash. AGDC used the current version of BPIPPRM, version 04274, to determine the building profiles needed by AERMOD for the GTP EUs.

AGDC also used BPIPPRM to determine most of the building profiles for the off-site EUs. However, as discussed in Section 2.4.2 (**Modeling Protocol Submittal**) of this report, AGDC used the results from their EBD wind tunnel study for select wind directions for several of the EUs. The wind directions and EUs are listed in Table 5 of Attachment 3 of the protocol (*Study Report Equivalent Building Determination for the Central Gas Facility and the Central Compression Plant at Prudhoe Bay*). The Department approved the use of the EBD parameters in its December 13, 2017 approval of the PSD modeling protocol.

The Department used a proprietary 3-D visualization program to review AGDC's characterization of the exhaust stacks and structures. The characterization of the GTP EUs match the main pad and camp pad layouts shown in Figures 5-5 and 5-6, respectively, of Attachment 5 of the permit application. AGDC's characterization of the CCP/CGF EUs and building configurations match the facility layouts on file from previous BPXA submittals, along with the oblique photographs provided by AGDC in Figures 11 and 12 of Attachment 3 of the PSD modeling protocol. BPIPPRM indicated that the GTP exhaust stacks are within the GEP stack height requirements.

5.12. Ambient Air Boundary

The AAAQS and increments only apply in *ambient air* locations, which has been defined by EPA as, "*that portion of the atmosphere, external to buildings, to which the general public has access*." [47] Applicants may therefore exclude areas that they own or lease from their ambient demonstration if public access is "*precluded by a fence or other physical barrier*." [48]

AGDC used the edge of the main pad, and the edge of the camp pad, as their ambient air boundaries. Using the pad edge is a standard and acceptable approach for modeling North Slope stationary sources.

5.13. Worker Housing

AGDC will need to house their workers on-site due to the project's remote location. Worker housing areas must be treated as ambient air, except under the conditions described in the Department's *Ambient Air Quality Issues at Worker Housing* policy.[49] The conditions are:

1) the worker housing area is located within a secure or remote site;
2) the worker housing area is for official business/worker use only; and
3) the operator has a written policy stating that the on-site workers are on 24-hour call.

The GTP worker housing area meets the above exception. AGDC therefore did not treat the worker housing area as ambient air.

5.14. Receptor Grid

A dispersion model will calculate the concentration of the modeled pollutant at locations defined by the user. These locations are called receptors. Designated patterns of receptors are called receptor grids.

AGDC described their receptor grid in Section 5.4 of Attachment 5 of their permit application. In summary, AGDC used a receptor grid of decreasing resolution with distance from the ambient boundary for their project impact analysis. The receptor resolutions are:

- Every 25 m along the ambient boundary (pad edge);
- 25 m from the ambient boundary to a distance of at least 100 m from pad edge;
- 50 m from 100 m to 300 m (or more) from pad edge;
- 100 m from 300 m to 1 km (or more) from pad edge; and

[47] The term "ambient air" is defined in 40 CFR 50.1. The Alaska Legislature has also adopted the definition by reference in AS 46.14.90(2).

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

[49] Policy and Procedure 04.02.108: *Ambient Air Quality Issues at Worker Housing*; October 8, 2004.

- On the eastern side (near CCP and CGF), 250 m from 1 km to 1.5 km.

AGDC expanded the receptor grid and added increased resolution around the CCP and CGF pads in the cumulative impact analyses. However, they did not include receptors within the CCP and CGF ambient air boundaries since the GTP impacts were already assess at those locations. This approach is consistent with EPA and Department guidance.[50, 51] For the cumulative impact analyses, the receptor resolutions are:

- Every 25 m along the ambient boundary (pad edge) for each stationary source (i.e., along the GTP boundary and along the CCP/CGF boundary);
- 25 m from the ambient boundary to a distance of at least 100 m from each stationary source;
- 50 m from 100 m to 300 m (or more) from pad edge;
- 100 m from 300 m to 1 km (or more) from pad edge;
- 250 m from 1 km to 5 km; and
- 500 m from 5 km to 10 km.

AGDC's grid has sufficient resolution and coverage to determine the maximum impacts. The maximum impacts generally occur near the GTP pad, or near the CCP/CGF pads.

5.15. Off-Site Impacts

The air quality impact from natural and regional sources, along with long-range transport from far away sources, must be accounted for in a cumulative AAAQS demonstration. The increment consuming impact from nearby off-site anthropogenic sources must likewise be accounted for in a cumulative increment demonstration. The approach for incorporating these impacts must be evaluated on a case-specific basis for each type of assessment and for each pollutant.

The two nearest off-site facilities, CCP and CGF, are close enough to have significant concentration gradients in the vicinity of GTP. The more distant facilities would not. AGDC therefore included CCP/CGF in the cumulative AAAQS, and cumulative increment, modeling analyses. They used ambient data collected within PBU to represent the impacts from all other sources in their cumulative AAAQS demonstrations.

AGDC used the NO_2 and SO_2 data collected by BPXA at their A-Pad monitoring station to represent the background NO_2 and SO_2 concentrations. A-Pad is located approximately 11.5 km southwest of GTP. BPXA established the station in 1986 in order to measure the general background concentrations within PBU. The data is frequently used in AAAQS analyses of stationary sources located in the greater Prudhoe Bay area.

[50] EPA memorandum from Robert D. Bauman to Gerald Fontenot; *Ambient Air*; October 17, 1989.
[51] Letter from Alan Schuler (Department) to William Steigers (Steigers Corporation); *Request for ADEC Approval of Multi-Source Receptor Grid Modeling Protocol*; April 3, 1996. The letter is posted on the Department's web-site at: http://dec.alaska.gov/air/air-permit/dispersion-modeling/.

AGDC used the A-Pad data collected from 2010 through 2014 for their SO_2 and annual NO_2 AAAQS analyses. They used 2009 through 2013 data for the 1-hour NO_2 AAAQS analysis for the reason described later in this subsection. In both cases, the data were previously reviewed by the Department and approved as PSD-quality. The resulting maximum measured concentrations are also publicly available through the *Industrial Data Summary* that the Department posts at http://dec.alaska.gov/air/air-permit. The values selected by AGDC are listed in Table 3-1 of the GTP Modeling Report, as well as Table 11 of this report. AGDC selected generally reasonable values for the background concentrations.[52]

BPXA does not measure PM at A-Pad. However, they do measure both PM-10 and PM-2.5 at their CCP station. AGDC used CCP monitoring data to represent the background PM-10 and PM-2.5 concentrations. The use of CCP data provides for a conservative AAAQS analysis since the CCP/CGF impacts are also accounted for through modeling.

AGDC stated that they used the 2014 PM concentrations. However, the selected values do not match the values posted in the Department's *Industrial Data Summary*. The Department is therefore using the subsequently measured values listed in Table 7 below in Section 6 of this report.

Table 7. PM Background Concentrations

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)	Comments
PM-10	24-hr	60	Largest 2nd high concentration measured in calendar years 2013 - 2016
PM-2.5	24-hr	12	Three-year average of 98th percentile for calendar years 2014 - 2016

There are various ways to add a background concentration to the modeled concentration in an AERMOD analysis. The long-standing practice is to manually add the two numbers. However, the most recent versions of AERMOD include an option where the background concentration can be automatically added to the modeled concentration. This option also allows applicants to include temporarily-varying background concentrations in their ambient demonstrations. AGDC used the manual approach in their annual NO_2, 24-hr PM-10, 24-hr PM-2.5, 1-hr SO_2, 3-hr SO_2, and 24-hr SO_2 AAAQS demonstrations. They used the more detailed, temporarily-varying option for their 1-hour NO_2 AAAQS demonstration.

AGDC's approach for varying the 1-hour NO_2 background concentration is described in Section 3.2 of the GTP Modeling Report. Their approach is both reasonable and consistent with EPA guidance.[33] In summary, AGDC noted that the NO_2 concentrations measured at A-Pad are strongly dependent on wind speed. They therefore sorted the measured 1-hour concentrations by the wind speed, using the default wind speed categories listed in the

52 Table 3-1 of the GTP Modeling Report states the maximum annual NO_2 concentration measured at A-Pad in calendar years 2010 through 2014 is 6.0 $\mu g/m^3$. The actual value reported in the Department's Industrial Data Summary is 6.2 $\mu g/m^3$. The Department is reporting the 6.2 $\mu g/m^3$ value in the results section of this report.

AERMOD User's Guide. They then selected the 98th percentile of the hourly NO_2 concentrations as the background concentration for the given wind speed category. They used concurrent 2009 – 2013 NO_2 and meteorological data, which provided a robust analysis. The resulting background concentrations are reiterated below in Table 8 in both parts per billion by volume (ppbv) and μg/m^3. AGDC's approach for temporarily varying the 1-hour NO_2 background concentration is identical to the approach used by the *Workgroup for Global Air Permit Policy Development for Temporary Oil and Gas Drill Rigs* (Workgroup) and approved by the Department for use in the Minor General Permit 2 ambient demonstration.[53] The Department continues to approve the approach, along with the resulting background concentrations.

Table 8. 1-hour NO_2 Background Concentrations by Wind Speed

Wind Speed (Ws) Category (m/s)	NO_2 Concentration	
	ppbv	μg/m^3
Ws < 1.54	25.9	48.8
1.54 ≤ Ws < 3.09	22.3	41.9
3.09 ≤ Ws < 5.14	15.9	29.9
5.14 ≤ Ws < 8.23	10.3	19.4
8.23 ≤ Ws < 10.8	10.7	20.1
Ws ≥ 10.8	13.4	25.2

5.16. Modeled Design Concentrations

EPA allows applicants to use modeled concentrations that are consistent with the form of the given standard or increment as their design concentrations. The highest concentrations must generally be used when comparing the modeled impacts to the SILs. However, the multi-year average of the highest concentrations may be used when comparing the 1-hour NO_2, 1-hour SO_2, 24-hour PM-2.5, and annual PM-2.5 impacts to the SILs – for purposes of demonstrating compliance with the AAAQS.[54] AGDC used the modeled concentrations that are consistent with the above description. The design concentrations used in AGDC's cumulative modeling analyses to demonstrate compliance with the AAAQS and Class II increments are summarized in Table 9.

[53] The 1-hour NO_2 background concentrations developed by the Workgroup is described in Appendix D of the October 17, 2017 report, *Ambient Demonstration for the North Slope Portable Oil and Gas Operation Simulation*. The report may be found on the Department's web-site at: http://dec.alaska.gov/media/9166/north-slope-pogo-simulation-modeling-report-final-101717.pdf.

[54] The maximum value from any year must be used for the other pollutants and averaging periods, and when comparing the 24-hour PM-2.5 and annual PM-2.5 impacts to the SILs for purposes of demonstrating compliance with the Class II increments.

Table 9. AGDC's Approach for Determining The Modeled Design Concentrations

Pollutant	Avg. Period	AAAQS	Class II Increment
NO_2	1-hour	h8h	--
	Annual	HY	HY
PM-10	24-hour	h6h	h2h
	Annual	--	HY
PM-2.5	24-hour	h8h	h2h
	Annual	MA	HY
SO_2	1-hour	h4h	--
	3-hour	h2h	h2h
	24-hour	h2h	h2h
	Annual	HY	HY
CO	1-hour	h2h	--
	8-hour	h2h	--

Table Notes:

h2h = the maximum high second-high concentration from any year.

h4h = the multi-year average of the high fourth-high daily maximum 1-hour concentrations.

h6h = the high sixth-high 24-hour concentration over five years.

h8h = high eighth-high. For purposes of 1-hour NO_2, the h8h is the five-year average of the high, eighth-high of the daily maximum 1-hour NO_2 concentrations. For purposes of 24-hour PM-2.5, the h8h is the five-year average of the high, eighth-high of the 24-hour PM-2.5 concentrations.

HY = highest annual average from any year.

MA = highest multi-year average of the annual concentrations at a given receptor.

-- = there is no AAAQS/increment (as applicable) for this pollutant/averaging period.

6. MODELING RESULTS AND DISCUSSION

The maximum project impacts are presented in Table 10. The SIL for each pollutant and averaging period is also presented for comparison. The maximum impacts exceed the applicable SIL for most pollutants and averaging periods. The annual SO_2, annual PM-2.5, annual PM-10, 1-hour CO, and 8-hour CO impacts are the exception. The Department further notes that the existing margin of compliance with the AAAQS exceeds the SIL for each of those pollutants.[55] Therefore, the GTP emissions will not cause or contribute to a violation of the annual SO_2, annual PM-2.5, 1-hour CO, and 8-hour CO AAAQS; or the annual SO_2, annual PM-2.5, and annual PM-10 Class II increments.

[55] The existing margin of compliance for a given AAAQS can be derived by subtracting the ambient concentration shown in Table 1 from the numerical value for the AAAQS. The existing margin of compliance is greater than the SIL for all pollutants and averaging periods modeled by AGDC.

Table 10. Maximum Project Impacts Compared to the SILs

Pollutant	Avg. Period	Max. Modeled Conc. (μg/m³)	SIL (μg/m³)
NO_2	1-hour	74.7	8
	Annual	2.6	1
SO_2	1-hour	27.9	8
	3-hour	49.0	25
	24-hour	20.6	5
	Annual	0.5	1
PM-2.5 (multi-year avg.)	24-hour	3.9	1.2
	Annual	0.22	0.3
PM-2.5 (max. impact from any year)	24-hour	8.9	1.2
	Annual	0.26	0.3
PM-10	24-hour	8.8	5
	Annual	0.26	1
CO	1-hour	448	2,000
	8-hour	180	500

<u>Table Note</u>: The multi-year average of the maximum PM-2.5 impacts may be compared to the PM-2.5 SILs for purposes of demonstrating compliance with the PM-2.5 AAAQS. However, the maximum PM-2.5 impact from any year must be compared to the PM-2.5 SILs for purposes of demonstrating compliance with the PM-2.5 increments. (See Section 5.16 of this report.)

The results from the cumulative AAAQS analyses, as revised by the Department, are presented in Table 11. The background concentrations, total impact, and AAAQS are also shown. All of the total impacts are less than the AAAQS.

Table 11. Maximum Impacts Compared to the AAAQS

Pollutant	Avg Period	Modeled Design Conc. (μg/m³)	Bkgd Conc. (μg/m³)	Total Impact (μg/m³)	AAAQS (μg/m³)
NO_2	1-hour	158.0	*See Note*	**158.0**	188
	Annual	14.0	6.2	**20.2**	100
PM-10	24-hour	21.4	60	**81.4**	150
PM-2.5	24-hour	14.5	12	**26.5**	35
SO_2	1-hour	39.2	9.4	**48.6**	196
	3-hour	226.9	21.0	**247.9**	1,300
	24-hour	32.1	8.1	**40.2**	365

<u>Table Note</u>: The 1-hour NO_2 background concentration is included in the modeled concentration. See Section 5.15 of this report.

The results from the cumulative increment analysis, as revised by the Department, are presented in Table 12. The modeled design concentrations are less than the Class II increment for all pollutants and averaging periods.

Table 12. Maximum Modeled Impacts Compared to the Class II Increments

Pollutant	Avg. Period	Modeled Design Conc. ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)
NO_2	Annual	11.4	25
PM-10	24-hour	17.0	30
PM-2.5	24-hour	4.8	9
SO_2	3-hour	153.8	512
	24-hour	31.2	91

7. OZONE IMPACTS

As discussed in Section 1 (**Introduction**) of this report, VOC is a triggered PSD-pollutant for the GTP project. There is no VOC AAAQS, but VOC and NOx emissions can form O_3, which does have an AAAQS. AGDC was therefore required to demonstrate compliance with the O_3 AAAQS per 40 CFR 52.21(k).

O_3 is not usually emitted directly into the air. It is instead created in the atmosphere through chemical reactions between NOx and VOC in the presence of sunlight. It is inherently a regional pollutant, the result of chemical reactions between emissions from many NOx and VOC sources over a period of hours or days, and over a large area.

The 2005 version of the Guideline does not list a recommended model for assessing the O_3 impact from an individual stationary source. Qualitative approaches are instead generally used to meet the 40 CFR 52.21(k) ambient demonstration requirement.

AGDC provided a background discussion regarding O_3 formation in Section 8 of the GTP Modeling Report. The discussion includes a trajectory analysis for days with "elevated" ozone concentrations using the HYSPLIT model. They also discussed several lower-48 Photochemical Grid Model (PGM) ozone analyses, and what the findings could mean with respect to the GTP project.

The Department did not take the time to review AGDC's trajectory analysis or PGM discussion since the following aspect of their O_3 demonstration is adequately convincing. AGDC provided a table in Attachment 3 of their permit application that summarized the 8-hour O_3 concentrations measured at various North Slope locations. They obtained the concentrations from the *Industrial Data Summary* that the Department posted on its web-site (see http://dec.alaska.gov/air/air-permit). AGDC then noted that the ambient O_3 concentrations are well below the AAAQS, even with the presence of large regional sources of precursor emissions. The maximum measured fourth high 8-hour concentration listed by AGDC is 0.054 ppm, which is less than the 0.070 ppm AAAQS.[56] AGDC summarized the regional NOx and VOC emissions, as reported in the 2011 NEI, to support their observation regarding the existing precursor emissions. AGDC estimated the regional emissions by using only the emissions from point sources located between the Arctic National Wildlife Refuge (ANWR) and the National Petroleum Reserve – Alaska.[57] The total regional emissions summarized by AGDC are substantially larger than the proposed GTP emissions, as shown below in Table 13. Therefore, the project should not cause or contribute to a violation of the 8-hour O_3 AAAQS given the current margin of compliance.

Table 13. GTP and 2011 NEI Emissions Comparison

Source	O_3 Precursor Emissions (tpy)		
	NOx	**VOC**	**Total**
GTP PTE (without maximum flaring)	2,231	304	2,535
Regional Emissions (per 2011 NEI)	37,399	125,535	162,934

Table Note: The Department was still evaluating AGDC's BACT analyses when it developed Table 13. The PTE therefore reflects the PTE provided by AGDC, which is the upper bound of what the final PTE may be for GTP.

8. ADDITIONAL IMPACT ANALYSES

PSD applicants must assess the impact from the proposed project and associated growth on visibility, soils, and vegetation, per 40 CFR 52.21(o) – *Additional Impact Analyses*. AGDC provided their additional impact analyses in Attachment 10 of their permit application. The Department's findings regarding their analyses are reported below.

8.1. Associated Growth Analysis

40 CFR 52.21(o)(2) requires PSD applicants to "*provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification*." AGDC does not expect industrial or commercial growth in the immediate vicinity of GTP, but they noted that some growth is possible in the Deadhorse area. With respect to employment, AGDC stated that they would be providing the infrastructure that would support the majority of growth in the worker population (see the related discussion in Section 5.13 of this report). AGDC noted that there could be some increase in worker population needed to support aviation and subcontractors within the Deadhorse area. However, they did not expect a significant net change from historical levels due to the recent decline in the worker population. AGDC concluded, "*Any*

[56] AGDC compared the maximum fourth-high concentration from any given year to the 8-hour O_3 AAAQS. This is a conservative approach since the *three-year* average of the annual fourth-highest daily maximum 8-hour O_3 concentration must exceed 0.070 ppm before there is an actual violation of the AAAQS – see 18 AAC 50.010(4).

[57] See Attachment 3 of AGDC's permit application for additional details.

actual growth resulting in emissions increases would be minimal..." The Department accepts AGDC's assessment.[58]

8.2. Visibility Impacts

PSD applicants must assess whether the emissions from their stationary source, including associated growth, will impair visibility. Visibility impairment means any humanly perceptible change in visibility, such as visual range, contrast, or coloration, from that which would have existed under natural conditions. Visibility impacts can occur as visible plumes, i.e., "plume blight," or in a general, area-wide reduction in visibility, also known as "regional haze". Alaska does not have standards for plume blight. For Class I areas, the Federal Land Manager provides the desired thresholds. There are no established thresholds for Class II areas. The typical tool for assessing plume blight is EPA's VISCREEN model.

The maximum range of VISCREEN is 50 km. When Class I areas lie beyond that range, as in the case at hand, the Department recommends that the applicant use the 50 km maximum range as the source to observer distance. This approach provides the upper bound of the potential plume blight impacts at more distance locations. This same distance (50 km) would also be used as the "nearest" source to boundary distance per page 24 of EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised)*.[59]

Since there are no Class II visibility thresholds, VISCREEN compares the visibility impacts to the Class I thresholds. VISCREEN provides results for impacts located inside a Class I area and for impacts located outside a Class I area. The latter is used in situations where there is an "integral vista." In situations where there are no integral vistas, applicants only need to use the results for impacts located inside a Class I area. Alaska only has two integral vistas, both of which are associated with Denali National Park. Since the integral vistas are well beyond the 50 km range of VISCREEN, the Department informed AGDC that they only needed to report the "inside" results.

AGDC conducted two VISCREEN runs: one with the source to observer distance set at 50 km (as recommended by the Department); and the other (for informational purposes), with the source to observer distance at 93 km (the nearest distance to ANWR). They provided their findings in Attachment 10 of their permit application.

AGDC used the current version of VISCREEN, version 13190, to estimate their worst-case plume blight. They appropriately assumed an O_3 concentration of 40 ppbv and a "background visual range" of 258 km. AGDC used the "Level 1" approach of assuming a constant 1.0 m/s wind speed and extremely stable atmospheric conditions ("F" stability class). This approach showed potential plume blight at 50 km.

[58] AGDC did not include the Pipeline Stations and Liquefaction Plant in their Associated Growth Analyses since those stationary sources will not be located in the same area as GTP. As previously noted in Section 5.6.3 of this report, the ambient impacts associated with each of those stationary sources will be assessed, as warranted, under the permit requirements for that stationary source.

[59] *Workbook for Plume Visual Impact Screening and Analysis (Revised),* (EPA-454/R-92-023); October 1992.

The Department did not require AGDC to conduct a more rigorous visibility analysis since there are no plume blight thresholds for Class II areas. The Department also notes that a Level 1 analysis for a source to observer distance of 50 km is *extremely* conservative. It represents a scenario that is unlikely to occur since the wind would need to hold steady for the entire 87.5 hours (three and a half days) needed for the plume to travel that distance at only 1.0 m/s.

8.3. Soil and Vegetation Impacts

The ambient demonstration provided by applicants is typically adequate for showing that their air emissions will not cause adverse soil or vegetation impacts. Congress established "primary" NAAQS and "secondary" NAAQS in Section 109(b) of the CAA. The primary NAAQS protect public health, while the secondary NAAQS protect public welfare. Congress further stated in Section 302(h) of the CAA, "*All language referring to the effects of **welfare** includes, but is not limited to, effects on **soils**, water, crops, **vegetation**, …*" (emphasis added).The AAAQS and primary NAAQS are identical for each of the modeled pollutants. However, the annual PM-2.5 secondary NAAQS (15 μg/m^3) is less stringent than the annual PM-2.5 primary NAAQS/AAAQS (12 μg/m^3). Therefore, a modeling analysis that demonstrates compliance with the AAAQS also demonstrates compliance with the secondary NAAQS.

AGDC demonstrated that they can comply with the AAAQS. Therefore, their ambient analysis generally demonstrates that they will not have adverse soil or vegetation impacts. The maximum cumulative impacts for the PSD-triggered pollutants with secondary NAAQS are reiterated in Table 14.[60]

Table 14. Maximum Total Impacts Compared to the Secondary NAAQS

Pollutant	Avg. Period	Total Impact (μg/m^3)	Secondary NAAQS (μg/m^3)
NO_2	Annual	**20.2**	100
PM-2.5	24-hour	**26.5**	35
PM-10	24-hour	**81.4**	150
SO_2	3-hour	**247.9**	1,300

AGDC conducted an additional assessment on the potential impact on lichens. Lichens are more sensitive to air pollutants than vascular plants since they lack roots and derive all growth requirements from the atmosphere. Some lichen species are adversely affected when the annual average SO_2 concentration ranges between 13 to 26 μg/m^3. [61] While it is not known whether lichens on the North Slope have this same sensitivity, these values provide a

[60] AGDC demonstrated that the annual PM-2.5 project impact is less than the SIL. The analysis therefore also demonstrates that the annual PM-2.5 impacts will not adversely affect local soil and vegetation.
[61] *Air Quality Monitoring on the Tongass National Forest* (USDA – Forest Service); September 1994.

surrogate measure of the potential sensitivity threshold. The maximum modeled concentration plus background is 4.6 μg/m^3. This is well below the 13 μg/m^3 threshold.

9. CONCLUSIONS

The Department concludes the following based on its review of AGDC's permit application and ambient demonstrations:

1. AGDC's characterizations of the proposed exhaust stacks comply with the stack height and dispersion requirements described in 40 CFR 52.21(h) ***Stack Heights***.
2. AGDC's ambient demonstration, as modified by the Department, satisfies the ***Source Impact Analysis*** requirements of 40 CFR 52.21(k). AGDC demonstrated that the NOx, SO_2, PM-10, PM-2.5, CO, and VOC emissions associated with operating the stationary source, within the restrictions listed in this report, will not cause or contribute to a violation of the NO_2, SO_2, PM-10, PM-2.5, CO, and O_3 AAAQS. They also demonstrated that the emissions will not cause or contribute to a violation of the NO_2, SO_2, PM-10, and PM-2.5 Class II increments.
3. AGDC appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.
4. AGDC conducted their modeling analysis in a manner consistent with the Guideline, as required under 18 AAC 50.215(b)(1).
5. The 2015 and 2016 ambient pollutant data measured at CCP satisfies the ***Preapplication Analysis*** requirements of 40 CFR 52.21(m)(1).
6. AGDC provided the ***Additional Impact Analyses*** required under 40 CFR 52.21(o).

The Department developed permit conditions in Construction Permit AQ1524CPT01 to ensure AGDC complies with the AAAQS and Class II increments. These conditions are *summarized* as follows:

- To protect the NO_2, CO, PM-10, PM-2.5, and SO_2 AAAQS, and the NO_2, PM-10 and PM-2.5 Class II increments:

  Stack Configuration

  - Construct and maintain vertical, uncapped exhaust stacks for all heaters and reciprocating engines (**EUs 31 – 44**), and on all temporary camp engines. AGDC may nevertheless use flapper-style rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

  Stack Heights

  - Construct and maintain exhaust stacks with release points above the gravel pad surface that equals or exceeds the minimum height listed in Table 5 for that EU.

Concurrent Operating Limits

- o Do not operate more than two of the three Building Heat Medium Heaters (**EUs 31 – 33**) at a time, except for periodic load shifting purposes.
- o Do not operate more than two of the three Operations Camp Heaters (**EUs 36 – 38**) at a time, except for periodic load shifting purposes.

- To protect the 1-hour and annual NO_2 AAAQS, the 1-hour and annual SO_2 AAAQS, the annual PM-2.5 AAAQS, the annual NO_2 Class II increment, the annual SO_2 Class II increment, the annual PM-10 Class II increment, and the annual PM-2.5 Class II increment, limit the operation of each of the six reciprocating engines (**EUs 39 – 44**) to 500 hr/yr.
- To protect the 24-hour PM-10 AAAQS, the 24-hour PM-2.5 AAAQS, and the annual PM-2.5 AAAQS during the construction phase:
  - o Use the best management practices described in the permit to minimize the fugitve dust emissions from construction activities.
  - o Install and operate one or more air quality monitoring stations to measure the actual PM-2.5 and PM-10 ambient concentrations. Take additional actions to reduce the fugitive dust emissions if the AAAQS become threatened.
- To protect the 1-hour, 3-hour, 24-hour, and annual SO_2 AAAQS; and the 3-hour, 24-hour, and annual SO_2 Class II increments, AGDC shall:
  - o Limit the sulfur content of the diesel fuel to 15 ppmw; and
  - o Limit the total sulfur content of the fuel gas to 96 ppmv.