ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Amendments to:

State Air Quality Control Plan

Volume III: Appendix III.K.13

Alaska Regional Haze State Implementation Plan

2nd Implementation Period

Appendix to Section III.K.13.F

Adopted

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Mike J. Dunleavy, Governor

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III.K.13.F APPENDIX TECHNICAL ANALYSIS OF STATE CONTROLLABLE SOURCES

SOURCES ELIMINATED DURING STEP TWO Q/D PROCESS

1 Introduction

As explained in Section 1 of the III.K.13.F Technical Analysis of State Controllable Sources part of the SIP, ADEC used a two-step approach to determine which sources would be selected for further analysis. Step one involved using a WEP SO_4 analysis to obtain a broad list of sources and step two involved further refining the list by examining the quantity of SO_2 emitted by the source in tons in 2017 and dividing that number by the kilometers to nearest Class I area (Q/d approach). During Step 2, if the Q/d value for SO_2 emissions divided by distance was below 1.0, the source was eliminated from further consideration for full evaluation. However, ADEC did include additional justification in this appendix document as to why these sources do not need to be further analyzed during this round of Regional Haze. The stationary sources that were eliminated during step 2 as well as sector sources can be seen below in Table III.K.13.F-A1.

Table III.K.13.F-A1 Facility selection to undergo review

	Sector	Facility	Denali		Simeonof	Tuxedni		Review Section
			DENA1	TRCR1	SIME1	KPB01	TUXE	
7	Nat. Security	Clear Air Force Base	Rank point 2014					2a
8	Manufact./ Seafood Process.	Trident Seafoods - Sand Point Facility			Rank point 2014/2017		Rank point 2014 (MID)	2b
9	Oil & Gas	Christy Lee/Drift River					Rank point 2014/2017 (MID)	2c
10	Power Plant	Bernice Lake Combustion Plant		Rank point 2014		Rank point 2014 (Top 20%)		2d
11	Power Plant	JBER-Electric, Gas, Drinking Water & Sanitary Services						2e
12	Power Plant	Matanuska Electric - Eklutna EGU						2f
13	Oil & Gas	Platform A		Rank point 2014		Rank point 2014 (Top 20%)		2g

14	Oil & Gas	Monopod Platform		Rank point 2014		Rank point 2014 (Top 20%)	Rank Point 2014 (MID, Top 20%)	2h
15	Oil & Gas	Grayling Platform		Rank point 2014		Rank point 2014 (Top 20%)	Rank Point 2014 (MID, Top 20%)	2i
16	Oil & Gas	Dolly Varden Platform		Rank point 2014/2017		Rank point 2014 (Top 20%)	Rank point 2014/2017(MID, Top 20%)	2j
17	Oil & Gas	King Salmon		Rank point 2014		Rank point 2014 (Top 20%)	Rank Point 2014 (MID, Top 20%)	2k
18	Oil & Gas	Steelhead		Rank point 2017			Rank Point 2017 (MID, Top 20%)	2l
19	Oil & Gas	BlueCrest Cosmopolitan				Rank point 2017 (Top 20%)		2m
20	Transport,	Ted Stevens International (ORL)		MID WEP		Top 20% WEP	Top 20% WEP	3a
	Transport	Ted Stevens International (Aviation Non-Point)		MID WEP		Top 20% WEP	Top 20% WEP	4h
21	Transport	Port of Anchorage (ORL)		MID WEP				3b
	Transport	Port of Anchorage (Marine Sector)		MID WEP				4a
22	Transport	Port McKenzie		MID WEP				4g
23	Transport	Trapper Creek Aviation		MID WEP				4i
24	Transport	Homer Aviation, Port		MID WEP		Top 20% WEP		4j, 4k, & 4l

25	Transport	Ninilchik		MID WEP		Top 20% WEP	Top 20% WEP	4m
26	Transport	Alaska Railroad		MID WEP				4c & 4n

2 Limited Review of Stationary Source

a. US Air Force: Clear Air Force Station

The Clear Air Force Station (Clear AFS) is owned and operated by the USAF, and the USAF is the permittee for the stationary source's Title V Operating Permit AQ0318TVP04 Revision 1. The SIC code for this stationary source is 9711 – National Security. The main stationary emission-generating activities at Clear AFS are fuel combustion sources. Typical fugitive sources at Clear AFS include firefighting training exercises and general miscellaneous chemical usage (e.g., emissions that result from the use of paints). Other fugitive dust sources include activities such as site preparation ("grading"), construction, and/or demolition. Stack emissions include units such as combustion sources (e.g., boilers and emergency generators), where emissions are exhausted through a stack/vent to the atmosphere. Air emissions at Clear AFS are generated primarily from operation of the boilers and furnaces, emergency power generators, and water pumps.

The Clear AFS EUs are listed below in Table III.K.13.F-A2.

Table III.K.13.F-A2 Clear Air Force Station Emission Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Bldg No.	Installation or Construction Date
Boilers					
44	Liquid-fired Boiler #1	Burnham 3P-400-50-0-PF	16.74 MMBtu/hr	230	2015
45	Liquid-fired Boiler #2	Burnham 3P-400-50-0-PF	16.74 MMBtu/hr	230	2015
46	Liquid-fired Boiler #3	Burnham 3P-400-50-0-PF	16.74 MMBtu/hr	230	2015
300	MCF Heating Boiler	Fulton VTG 6000DF, #10013	6.0 MMBtu/hr	900	2019
301	MCF Heating Boiler	Fulton VTG 6000DF, #10009	6.0 MMBtu/hr	900	2019
302	MCF Heating Boiler	Fulton VTG 6000DF, #10012	6.0 MMBtu/hr	900	2019
303	MCF Heating Boiler	Fulton VTG 3000DF, #10017	3.0 MMBtu/hr	900	2019
304	MCF Heating Boiler	Fulton VTG 3000DF, #10019	3.0 MMBtu/hr	900	2019
305	Dormitory Boiler	TBD	3.0 MMBtu/hr		TBD

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Bldg No.	Installation or Construction Date
Emergency Diesel Engines					
8	Diesel Generator	Perkins U898179F	30 kW	251	2000
9	Diesel Generator	Perkins U896501	30 kW	37	2000
11	Diesel Water Pump	Waukesha 1110843	200 hp	199	1960
12	Diesel Water Pump	Continental RD5721621	200 hp	5	1960
38	Diesel Well Pump	Caterpillar #1 03Z17016	200 hp	800	2000
39	Diesel Well Pump	Caterpillar #2 03217011	200 hp	800	2000
43	Emergency Generator	MTU 18V2000, DS1250	1,250 kW	502	2015
101	Emergency Generator	Detroit Diesel 20V4000G83L	3,490 kW	801	2012
102	Emergency Generator	Detroit Diesel 20V4000G83L	3,490 kW	801	2012
103	Emergency Generator	Detroit Diesel 20V4000G83L	3,490 kW	801	2016
200	Temporary Generator	MTU 12V4000G43 #5262012927	1,500 kW	907	2019
201	LPP Generator	Caterpillar C175-20	3,600 kW	901	TBD
202	LPP Generator	Caterpillar C175-20	3,600 kW	901	TBD
203	LPP Generator	Caterpillar C175-20	3,600 kW	901	TBD
204	LPP Generator	Caterpillar C175-20	3,600 kW	901	TBD
205	LPP Generator	Caterpillar C175-20	3,600 kW	901	TBD
206	LPP Generator	Caterpillar C175-20	3,600 kW	901	TBD
207	LPP Generator	Caterpillar C175-20	3,600 kW	901	TBD
208	Fire Dept. Generator	Caterpillar C9 ATAAC	300 kW	241	2019
Gasoline Storage Tanks					
104	Tank 673	Bulk, Gasoline for Vehicles (Tank 3)	8,000 gallons	260	1994
105	Tank 674	Bulk, Gasoline for Vehicles (Tank 4)	8,000 gallons	260	1994

ADEC looked back over the previous six-year period (2014-2019) for which data is currently available to determine the sources SO_2 emissions. ADEC used the NEI for SO_2 emissions from 2014 and 2017 (the only year that NEI information was available for the source) and used emission fee estimates for the remaining years 2015, 2016, 2018, and 2019. During this timeframe, the stationary source's only year of sizeable SO_2 emissions occurred in 2014 at 231.21 tons, as can be seen below in Table III.K.13.F-A3.

Table III.K.13.F-A3 Clear Air Force Station SO_2 Emissions

Calendar Year	SO_2 Emitted (tons)
2019	0.06
2018	0.07
2017	0.07
2016	3.17
2015	0.04
2014	213.21

As can be seen from Table III.K.13.F-A3, Clear AFS has had a steep drop in emissions after 2014. In May 2014, ADEC received an application to remove the three 177 MMBtu/hr coal-fired boilers that made up Clear AFS's Combined Heat and Power Plant (CHPP). The decommissioning of the CHPP was completed in January 2016. Now that Clear AFS is connected to GVEA's power grid, they only operate smaller building heaters, fire pump engines, and emergency generators. This has resulted in SO_2 emissions of less than 0.1 tpy in each of the last three years.

The conclusion of ADEC's review for USAF's Clear AFS is that the stationary source was identified in the step one WEP analysis based on emissions from 2014 alone, when the stationary source was still operating a coal-fired boiler CHPP. Once the CHPP portion of the stationary source was decommissioned they have had unsubstantial SO_2 emissions that would have nominal impacts on visibility. Therefore, the stationary source does not require any further review as actual SO_2 emissions from the stationary source cannot sizably be lowered any further. ADEC will continue to monitor the SO_2 emissions from the Clear AFS to ensure that there are no substantial increases going forward that would negatively impact RH.

b. Trident Seafoods Corporation: Sand Point Facility

The Sand Point Facility is owned and operated by Trident Seafoods Corporation (Trident), and Trident is the permittee for the stationary source's Title V Operating Permit AQ0232TVP04. The SIC codes for this stationary source are 2091- Canned and Cured Fish and Seafoods and 2092 - Prepared, Fresh, or Frozen Fish and Seafoods. The stationary source consists of six diesel electric generator sets, three process heat oil-fired boilers, and a fish meal dryer; each is listed as significant EUs in Table III.K.13.F-A4. The stationary source also owns insignificant EUs that include 14 fuel and fish oil storage tanks and six small diesel-fired bunkhouse boilers.

Table III.K.13.F-A4 Sand Point Facility Emissions Unit Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Construction or Installation Date
Generator Group				

1	Diesel Electric Generator	Caterpillar Model D3512A, Serial #24Z02425	1,220 kW	1999
2	Diesel Electric Generator	Caterpillar Model D399, Serial #35B04981	906 kW	1986
3	Diesel Electric Generator	Caterpillar Model D3412, Serial #81Z05460	664 kW	1986
4	Diesel Electric Generator	Caterpillar Model D3412, Serial #81Z05208	664 kW	1986
5	Diesel Electric Generator	Caterpillar Model D3512A, Serial #24Z02391	1,220 kW	1990
6	Diesel Electric Generator	Caterpillar Model D3512A, Serial #24Z02055	1,349 kW	1996
Boiler Group				
8	Fish Meal Dryer	Pedar Halvorsen Furnace, Serial #16740	17.8 MMBtu/hr	1996
9	Oil-Fired Boiler	William Davis Steam Boiler, Model #767	16.4 MMBtu/hr	1975
10	Oil-Fired Boiler	Cleaver Brooks Steam Boiler, Serial #L54314	20.9 MMBtu/hr	1972/2006[1]
11	Oil-Fired Boiler	Superior Steam Boiler, Serial #11313	2.05 MMBtu/hr	1994

Table Notes: [1] EU ID 10 was originally constructed in 1972, but it was installed at the stationary source in 2006.

ADEC looked back over the previous six-year period (2014-2019) for which data is currently available to determine the sources actual SO_2 emissions. ADEC used the NEI for SO_2 emissions from 2014 and 2017 (the only year that NEI information was available for the source) and used emission fee estimates for the remaining years 2015, 2016, 2018, and 2019. During this time period the source combusted diesel fuel with a maximum sulfur content of 0.0015 percent by weight (ULSD). Actual SO_2 emissions from 2014 through 2019 peaked in 2015 at 0.17 tons, as can be seen below in Table III.K.13.F-A5.

Table III.K.13.F-A5 Trident Sand Point Facility SO_2 Emissions

Calendar Year	SO_2 Emitted (tons)
2019	0.07
2018	0.03
2017	0.09
2016	0.11
2015	0.17
2014	0.08

The conclusion of ADEC's review for Trident's Sand Point Facility is that the stationary source is already using the most effective SO_2 control possible (combusting ULSD) in all of their fuel burning EUs. Therefore, the stationary source's actual SO_2 emissions cannot be lowered any further. ADEC will continue to monitor the SO_2 emissions from the Sand Point Facility to ensure that there are no substantial increases going forward that would negatively impact RH.

c. Harvest Alaska, LLC: Drift River/Christy Lee Platforms

The Harvest Alaska, LLC Drift River Platform/Christy Lee Platform was decommissioned as of October 2019. ADEC issued a Rescission Request Approval Letter for the source's Title V Operating Permit AQ0190TVP03 Rev. 1 on December 12, 2019. Therefore, the stationary source is no longer producing air emissions and does not need to be considered for further evaluation.

d. Alaska Electric and Energy Cooperative: Bernice Lake Combustion Turbine Plant

The Bernice Lake Combustion Turbine Plant (BCT) is owned and operated by Alaska Electric and Energy Cooperative (AEEC), and AEEC is the permittee for the stationary source's Title V Operating Permit AQ0086TVP04. The SIC code for this stationary source is 4911 – Electric Services. The stationary source is a power generation plant with three natural gas-fired turbines and three diesel-fired black start engines. These EUs are listed below in Table III.K.13.F-A6. The stationary source also owns insignificant EUs that include several gas-fired heaters.

Table III.K.13.F-A6 Bernice Lake Combustion Turbine Plant Emission Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Fuel	Rating/Size	Installation or Construction Date
1	Generating Unit No. 2	GE Frame 5 Turbine Model M	Natural Gas	263.0 MMBtu/hr	1971
2	Generating Unit No. 3	GE Frame 5 Turbine Model PG3541	Natural Gas	324.5 MMBtu/hr	1978
3	Generating Unit No. 4	GE Frame 5 Turbine Model PG3541	Natural Gas	324.5 MMBtu/hr	1981
4	Blackstart Unit 2	Cummins V785B300	Diesel	244 hp	1971
5	Blackstart Unit 3	Detroit Diesel 7123-7000	Diesel	374 hp	1978
6	Blackstart Unit 4	Cummins KT1150C	Diesel	567 hp	1981

ADEC looked back over the previous six-year period (2014-2019) for which data is currently available to determine the sources actual SO_2 emissions. ADEC used the NEI for SO_2 emissions from 2014 and 2017 (the only year that NEI information was available for the source) and used emission fee estimates for the remaining years 2015, 2016, 2018, and 2019. During this timeframe, SO_2 emissions peaked in 2014 at 0.048 tons, as can be seen below in Table III.K.13.F-A7.

Table III.K.13.F-A7 Bernice Lake Combustion Turbine Plant SO_2 Emissions

Calendar Year	SO_2 Emitted (tons)
2019	0.041
2018	0.016
2017	0.0060
2016	0.016
2015	0.017
2014	0.048

The conclusion of ADEC's review for AEEC's BCT is that the stationary source already has low SO_2 emissions as a direct result of exclusively combusting pipeline quality natural gas and ULSD in their EUs. Pipeline quality natural gas and ULSD are the most effective SO_2 control possible for liquid and gaseous fuel burning EUs. Therefore, the stationary source does not require any further review as actual SO_2 emissions from the stationary source cannot be lowered any further. ADEC will continue to monitor the SO_2 emissions from the BCT to ensure that there are no substantial increases going forward that would negatively impact RH.

e. *Doyon Utilities: Joint Base Elmendorf Richardson – Electric, Gas, Drinking Water and Sanitary Services*

The Joint Base Elmendorf Richardson – Electric, Gas, Drinking Water and Sanitary Services (JBER SIC 49) is owned and operated by Doyon Utilities, LLC (DU), and DU is the Permittee for the stationary source's Title V Operating Permit AQ0237TVP02 Revision 1. The SIC code for this stationary source is 4911 – Electric, Gas, and Sanitary Services. The stationary source is a power generation plant with five gas-fired generator engines, nine diesel-fired emergency engines, and two natural gas-fired boilers. These EUs are listed below in Table III.K.13.F-A8.

Table III.K.13.F-A8 JBER SIC 49 Emission Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Fuel Type[1]	Installation or Construction Date
13	Emergency Generator Engine	Waukesha/475DSU	75 kW	Diesel	1990
14	Emergency Generator Engine	John Deere/4039TF001	60 kW	Diesel	1980
25	Boiler	Cleaver Brooks/M48-700-4000	4.0 MMBtu/hr	Natural Gas	2003
26	Boiler	Cleaver Brooks/M4S-5000	5.0 MMBtu/hr	Natural Gas	Est. 2003
28	Emergency Engine	Cummins/HRS-6-P	150 kW	Diesel	1957
29	Emergency Engine	Cummins/HRS-6-P	150 kW	Diesel	1957
90	Backup Generator Engine	Caterpillar C-175	3,000 kW	Diesel	October 2010
91	Backup Generator Engine	Caterpillar C-175	3,000 kW	Diesel	October 2010

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Fuel Type[1]	Installation or Construction Date
92	Backup Generator Engine	Caterpillar C-175	3,000 kW	Diesel	October 2010
93	Emergency Generator Engine	Volvo Penta/TAD1241GE	526 hp	Diesel	2008
94	LFG Generator Engine	GE Jenbacher/JGS 420 GS-L.L	1,966/1,721 bhp2	LFG/NG	August 2012
95	LFG Generator Engine	GE Jenbacher/JGS 420 GS-L.L	1,966/1,721 bhp2	LFG/NG	August 2012
96	LFG Generator Engine	GE Jenbacher/JGS 420 GSL.L	1,966/1,721 bhp2	LFG/NG	August 2012
98	LFG Generator Engine	GE Jenbacher/JGS 420 GS-L.L	1,966/1,721 bhp2	LFG/NG	August 2012
99	LFG Generator Engine	GE Jenbacher/JGS 420 GS-L.L	1,966/1,721 bhp2	LFG/NG	August 2012
101	T1000 Emergency Generator Engine	Cummins QSB7-G5 NR3	324 hp	Diesel	2018

Table Notes: [1] LFG means landfill gas and NG means pipeline quality natural gas. The 1,966 brake horsepower (bhp) rating applies to LFG combustion in the engine, and the 1,721 bhp rating applies to NG combustion in the engine.

ADEC looked back over the previous six-year period (2014-2019) for which data is currently available to determine the sources actual SO_2 emissions. ADEC used the NEI for SO_2 emissions from 2014 and 2017 (the only year that NEI information was available for the source). There was no SO_2 emission information available for the non-triannual NEI years of 2015, 2016, 2018, and 2019. During this timeframe, SO_2 emissions peaked in 2014 with 3.9 tons as can be seen below in Table III.K.13.F-A9.

Table III.K.13.F-A9 JBER SIC 49 SO_2 Emissions

Calendar Year	SO_2 Emitted (tons)
2019	Not Available, <4.8
2018	Not Available, <4.8
2017	3.5
2016	Not Available, <4.8
2015	Not Available, <4.8
2014	3.9

In actuality, the source had 3.5 tons of SO_2 emissions in 2017, and it currently has a potential to emit of 4.8 tpy as described in Table F of the Statement of Basis to Operating Permit AQ0237TVP02 Revision 1. This value of 51.64 tons originally reported in the 2017 NEI was the result of EUs 25 and 26 reporting their emissions in pounds instead of tons. The low annual SO_2 emissions at the stationary source are a result of the emergency and backup generator EUs exclusively combusting ULSD, the boilers exclusively combusting natural gas, and the LFG generator engines combusting landfill gas and natural gas.

The conclusion of ADEC's review for DU's JBER SIC 49 is that the stationary source is already using effective SO_2 controls by combusting pipeline quality natural gas, landfill gas, and ULSD in all of their fuel burning EUs and has low annual SO_2 emissions of less than 4 tpy. Therefore, the stationary sources actual SO_2 emissions cannot sizably be lowered any further. ADEC will continue to monitor the SO_2 emissions from the JBER SIC-49 stationary source to ensure that there are no substantial increases going forward that would negatively impact RH.

f. Matanuska Electric Association, Inc.: Eklutna Generation Station

The Eklutna Generation Station is owned and operated by Matanuska Electric Association (MEA), and MEA is the permittee for the stationary source's Title V Operating Permit AQ1086TVP01. The SIC code for this stationary source is 4911 – Electric Services. The Eklutna Generation Station is a 171-megawatt dual fuel-fired electric power plant consisting of ten generator engines, two black start generators, two auxiliary boilers, a natural gas heater, and a firewater pump.

These EUs are listed below in Table III.K.13.F-A10.

Table III.K.13.F-A10 Eklutna Generation Station Emission Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Construction Date
1	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
2	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
3	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
4	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
5	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
6	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
7	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
8	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
9	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
10	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
11	Fire Pump Engine	John Deere JU6H-UFADN0	197 hp	ULSD	June 2012
12	Black Start Generator Engine	Cummins 1000DQFAD	1,490 hp	ULSD	June 2013
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	Natural Gas /ULSD	June 2013
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	Natural Gas /ULSD	June 2013
15	Diesel Storage Tank	Rockford 071301	436,842 gal	ULSD	March 2013
16	Diesel Storage Tank	Rockford 071301	436,842 gal	ULSD	March 2013
17	NG Fuel Heater	ETI	7.0 MMBtu/hr	Natural Gas	To be determined
18	Black Start Generator Engine	Cummins 1000DQFAD	1,490 hp	ULSD	June 2013

ADEC looked back over the previous six-year period (2014-2019) for which data is currently available to determine the sources SO_2 emissions. ADEC used the NEI for SO_2 emissions from 2017 (the only year that NEI information was available for the source) and used emission fee estimates for the remaining years 2015, 2016, 2018, and 2019. Note that no emissions data was available for 2015.

During this timeframe, the stationary source's SO_2 emissions peaked in 2014 at 20.6 tons, as can be seen below in Table III.K.13.F-A11.

Table III.K.13.F-A11 Eklutna Generation Station SO_2 Emissions

Calendar Year	SO_2 Emitted (tons)
2019	12.3
2018	10.1
2017	12.3
2016	13.6
2015	No Information Available
2014	20.6

Table Notes: SO_2 emissions were calculated with the maximum sulfur limits allowed in the permit as actual fuel sulfur concentrations was not provided to the Department.

Condition 11.1 of Operating Permit AQ1086TVP01 restricts the H_2S content of the natural gas burned in EUs at the stationary source to 20 ppmv. Condition 11.2 restricts the sulfur content of diesel fuel burned in EUs at the stationary source to 15 ppmw (ULSD). In facility operating reports (FORs) submitted throughout the review period MEA has certified compliance with Conditions 11.1 and 11.2 with the natural gas supplied from Enstar Natural Gas Company.

The conclusion of ADEC's review for MEA's Eklutna Generation Station is that the stationary source is already using the most effective SO_2 control possible (combusting pipeline quality natural gas and ULSD) in all of their fuel burning EUs. Therefore, the stationary source does not require any further review as actual SO_2 emissions from the stationary source cannot be lowered any further. ADEC will continue to monitor the SO_2 emissions from the Eklutna Generation Station to ensure that there are no substantial increases going forward that would negatively impact RH.

g. Hilcorp Alaska, LLC: Platform A

Platform A is owned and operated by Hilcorp Alaska, LLC (Hilcorp), and Hilcorp is the permittee for the stationary source's Title V Operating Permit, AQ0084TVP04. The SIC code for this stationary source is 1311 – Crude Petroleum and Natural Gas. Platform A is an offshore crude oil and gas production platform located approximately eight kilometers from the east forelands in Alaska's Cook Inlet. Stationary source operation yields crude oil and produced water in addition to some natural gas across several wells. The oil and produced water is delivered to an onshore facility by pipeline. Heat exchangers used during the separation process generate a small amount of gas that is used as fuel for indirectly fired heaters and boilers, or as a blanket gas for the surge tanks. A minimal amount of recovered gas is fired or flared on-site. Fuel gas, supplied by a third party, is piped to the platform from an onshore facility for use in platform EUs. This fuel gas is shipped-in using a separate pipeline from that of exported produced/recovered gas. Platform A consists of three large power generating turbines and two large reciprocating compressor engines, all fuel gas fired. Five liquid fuel fired engines, two small boilers, and a flare are also present at the stationary source.

These emissions units (EUs) are listed in Table III.K.13.F-A12.

Table III.K.13.F-A12 Platform A Emissions Unit Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Construction Date
1a	Turbine	Solar Saturn T-1301	13.29 MMBtu/hr	Fuel Gas	2010
2a	Turbine	Solar Saturn T-1301	13.29 MMBtu/hr	Fuel Gas	2010
3a	Turbine	Solar Saturn T-1301	13.29 MMBtu/hr	Fuel Gas	2013
6	Compressor A-CB1	Cooper Bessemer GMVA-8, S/N 47069	1,100 hp	Fuel Gas	1967
7	Compressor A-CB2	Cooper Bessemer GMVA-8, S/N 47131	1,100 hp	Fuel Gas	1967
10	Emergency Air Compressor A-EAC1	Perkins 4-236, S/N LD70152U978 786-L	73 hp	Liquid Fuel	1987
11	Rig Power A-ACDC1	Caterpillar D399, S/N 36Z503	1,000 hp	Liquid Fuel	1990
12	DC Rig Power A-DC2	Caterpillar D399, S/N 36Z01476	1,000 hp	Liquid Fuel	1990
13	Crane Engine A-EC1	Detroit Diesel 8V92, S/N 8VF134100	295 hp	Liquid Fuel	1990
14	Crane Engine A-WC1	Detroit Diesel 8V92, S/N 8VF105210	295 hp	Liquid Fuel	1989
15	Flare A-F1	Process Safety Flare	60 MMscf/yr	Fuel Gas	1965
n/a	Boiler (insignificant)	Clayton Boiler	4.1 MMBtu/hr	Fuel Gas	n/a

n/a	Boiler (insignificant)	Clayton Boiler	4.1 MMBtu/hr	Fuel Gas	n/a

Table Notes: The two Clayton Boilers are considered insignificant EUs for the purposes of Title V permitting. A 190hp liquid fuel-fired fire water pump, EU 16, was removed in the most recent Title V permitting action.

ADEC staff drew upon reported emissions data from 2015 through 2019 to determine the sources and scale of SO_2 emissions at Platform A. A review of Hilcorp's application materials and current permitting provides a characterization of the sulfur content of fuels fired at the source as well as the current SO_2 PTE.

A summary of the former information is provided in Table III.K.13.F-A13.

Table III.K.13.F-A13 Platform A Fuel Sulfur and SO_2 Emissions

Calendar Year	Avg. H_2S Content of Fired Fuel Gas (PPMV)	Max Sulfur Content of Fired Liquid Fuel (ppmw)	Actual SO_2 Emissions (tons)	Potential SO_2 Emissions (tons)
2019	31	15	0.9	45.3
2018	30	15	1.0	N/A
2017	40	15	0.7	N/A
2016	35	15	1.2	N/A
2015	32	15	0.4	N/A

Table Notes: The sulfur content of fired fuel gas, represented in this table, can be further characterized by in-situ sample data reported through routine compliance activities.

A review of the application materials for AQ0084TVP04 indicates that the emissions of SO_2 from Platform A are estimated, in part, assuming the firing of liquid fuels with a sulfur content of 500 ppmw. Hilcorp, however, certifies through compliance reporting that ULSD is exclusively used in the liquid fuel-fired EUs at Platform A, thus yielding actual emissions of the pollutant that are significantly lower. The former observation is also meaningful for the analysis at-hand as approximately 77-percent of potential SO_2 emissions are attributable to their liquid fuel-fired inventory. Similarly, approximately 69-percent of potential SO_2 emissions are attributable to two liquid fuel-fired EUs, 11 and 12, which are subject to a conservative operational assumption of 8,760 hours per year.

In an e-mail response to ADEC on March 10, 2021, Hilcorp provided an analytically supported cost estimate for solid scavenging sweetening controls installed on King Salmon platform, assumed to be representative of their Cook Inlet platforms. ADEC notes that the installation and operation of on-platform post-combustion controls is anticipated to be economically impractical due to considerably higher costs relative sweetening units. Hilcorp's results indicate an estimated cost of $24,000-per-ton of SO_2 removal, which is unlikely to be cost effective even by half, based on a review by ADEC staff. ADEC notes the following in support of this position:

The installation of pre-combustion controls on Hilcorp's platforms is anticipated to be technically infeasible due to size and weight of scavenging vessel, space constraints, and strict weight balance requirements of platforms. Were such systems installed, however, solid scavenging sweetening units are typically more cost effective than liquid scavenging units through a review of relevant BACT decisions; these units were the subject of scrutiny for this assessment. Implementing SO_2 sweetening controls would necessitate disposal of sweetening vessel condensate waste. While reductions in SO_2 emissions are possible, this approach externalizes pollutant impacts to liquid or solid waste streams of unknown environmental impact. Moreover, the relative anthropogenic contribution of platforms to visibility impacts in distant Class I areas unlikely to be meaningfully reduced even with significant reductions in platform SO_2 emissions.

Retrofit efforts would be required to install pre-combustion controls on-platform. The costs of such efforts are imbued with significant uncertainty and would entail regular flights for design, construction, and inspection staff as platform lodging is not available for these workers. Such an effort would impact both the economic feasibility of installation work and also generate externalized transportation-borne emissions. Similarly, multiple sweetening vessels would be employed in rotation given the need to regularly recharge treatment media. The handling and transportation of these vessels would be economically prohibitive and also generate externalized transportation-borne emissions via marine vessel use.

It is worth noting that the cost of on-platform electricity generation is typically greater than that of on-shore generation. Therefore, the economic feasibility of on-platform treatment options is less cost-effective by relative comparison. Moreover, realistic levels of control fall below 100-percent in application. The cost effectiveness of a control regime, even at high levels of control, are of questionable benefit on platforms that demonstrate relatively low emissions of SO_2.

ADEC, upon consideration of the former limited analysis, concludes that Hilcorp is employing the most practical and effective control regime for their SO_2 emissions at the Platform A stationary source. Said regime broadly entails the firing of low sulfur fuels at the source. The installation and use of pre- or post-combustion SO_2 controls are not anticipated to yield meaningful reductions in actual SO_2 emissions and are considered economically impractical on a case-specific basis. ADEC will continue to monitor the SO_2 emissions from this source to ensure that there are no increases that would adversely impact ongoing RH efforts.

h. Hilcorp Alaska, LLC: Monopod Platform

Monopod Platform is owned and operated by Hilcorp, and Hilcorp is the Permittee for the stationary source's Title V Operating Permit, AQ0067TVP03. The SIC code for this stationary source is 1311 – Crude Petroleum and Natural Gas. Monopod Platform is an offshore oil and gas production platform in Alaska's Cook Inlet. It handles the production of both oil and natural gas from wells and transportation of the produced streams to the onshore Trading Bay Production Facility. The Monopod Platform EU inventory consists of multiple turbines and engines for both power generation and gas compression. Other units are present at the source, which include engine generators, boilers, heaters, flares, and a glycol regenerator.

These EUs are listed in Table III.K.13.F-A14.

Table III.K.13.F-A14 Monopod Platform Emissions Unit Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Construction Date
1	Solar Centaur T-4500	Gas Compressor Set #1	4,400 hp	Fuel Gas	1995
2	Solar Centaur T-4500	Gas Compressor Set #2	4,400 hp	Fuel Gas	1996
3	Solar Saturn Turbine	AC Generator #1 Drive	750 kW	Fuel Gas	1969
4	Solar Saturn Turbine	Gas Lift Compressor	1,100 hp	Fuel Gas	1972
5	Solar Saturn Turbine	AC Generator #2 Drive	750 kW	Fuel Gas	1973
6	Solar Saturn Turbine	Waterflood Pump #1 Drive	1,100 hp	Fuel Gas	1970
7	Solar Saturn Turbine	Waterflood Pump #2 Drive	1,100 hp	Fuel Gas	1970
8a	MTU 12V4000G73	Drill Generator# 1	1,105 kW	Liquid Fuel	2011
9a	MTU 12V4000G73	Drill Generator# 2	1,105 kW	Liquid Fuel	2011
10a	MTU 12V4000G73	Drill Generator# 3	1,105 kW	Liquid Fuel	2011
13	Caterpillar 3406B-DITA engine	East Crane	420 hp	Liquid Fuel	1996
14	Detroit Diesel 671	West Crane	230 hp	Liquid Fuel	1997
15	Weil-McLain Boiler 88	Boiler	4.763 MMBtu/hr	Fuel Gas	1992
16	Glycol Regenerator	Triethylene Glycol (TEG) Dehydration Unit	10 MMscf/day	NA	1966
17	Flare (LP)	NW Low Pressure Flare – NW	91.5 MMscf/yr	Fuel Gas	1966
18	Flare and Pilot (HP)	NW High Pressure Flare – NW	1966	Fuel Gas	18
19	Flare (LP)	NW Low Pressure Flare – South	1966	Fuel Gas	19

20	Flare and Pilot (HP)	NW High Pressure Flare – South	1966	Fuel Gas	20
21	Caterpillar Diesel Engine 1	Fire Water Pump Drive	85 hp	Liquid Fuel	1971
22	Peerless Boiler	Boiler #2	2.8 MMBtu/hr	Fuel Gas	n/a
23a	Detroit Diesel	Emergency Generator Drive #7	685 hp	Liquid Fuel	2013
26	Solar Centaur 40	Generator Drive (SoLoNOx)	4,400 hp	Fuel Gas	2014 2
n/a	Clayton Boiler	Clayton Sigma Fire	50 bhp	Fuel Gas	2013
n/a	Diesel Beam Tank 1	Diesel Beam Tank 1	25,373 gal	Liquid Fuel	1966
n/a	Diesel Beam Tank 2	Diesel Beam Tank 2	25,373 gal	Liquid Fuel	1966
n/a	Diesel Beam Tank 3	Diesel Beam Tank 3	25,373 gal	Liquid Fuel	1966
n/a	Diesel Beam Tank 4	Diesel Beam Tank 4	25,373 gal	Liquid Fuel	1966
n/a	Crude Oil Ship Tank	Crude Oil Ship Tank	6,200 gal	Liquid Fuel	n/a
n/a	Diesel Day Tank	Diesel Day Tank	230 gal	Liquid Fuel	n/a
n/a	Diesel Day Tank	Diesel Day Tank	340 gal	Liquid Fuel	n/a
n/a	Diesel Crane Tank	Diesel Crane Tank	10 bbl	Liquid Fuel	n/a
n/a	Diesel Crane Tank	Diesel Crane Tank	10 bbl	Liquid Fuel	n/a

Table Notes: EUs 21, 22, the Clayton Boiler, and tanks are considered insignificant EUs for the purposes of Title V permitting. Turbine EU 26 has not been installed at the stationary source as of May 2019.

ADEC staff drew upon reported emissions data from 2015 through 2019 to determine the sources and scale of SO_2 emissions at Monopod Platform. A review of Hilcorp's application materials and current permitting provides a characterization of the sulfur content of fuels fired at the source as well as the current SO_2 PTE.

A summary of the former information is provided in Table III.K.13.F-A15.

Table III.K.13.F-A15 Monopod Platform SO_2 Emissions

Calendar Year	Avg. H_2S Content of Fired Fuel Gas (ppmv)	Max Sulfur Content of Fired Liquid Fuel (ppmw)	Actual SO_2 Emissions (tons)	Potential SO_2 Emissions (tons)

2019	250	15	20.0	63.0
2018	200	15	15.5	
2017	200	15	15.3	
2016	420	15	29.9	
2015	800	15	58.7	

A review of the application materials for AQ0067TVP03 indicates that the emissions of SO_2 from Monopod Platform are estimated, in part, assuming the firing of liquid fuels with a sulfur content of 15 ppmw in some EUs, though others rely upon a 300 to 500 ppmw assumption. Hilcorp, however, certifies through compliance reporting that ULSD is exclusively used in the liquid fuel-fired EUs at Monopod Platform, thus yielding actual emissions of the pollutant that are significantly lower. ADEC notes that the emissions of SO_2 at the stationary source are largely driven by the fuel gas-fired EUs; nearly half of the former emissions are attributable to the turbine EUs, which, like most equipment at the source, are conservatively assumed to operate 8,760 hours annually. It is worth further noting that actual SO_2 emissions at the source typically represent approximately one-half to one-third of estimated potentials.

Hilcorp has assumed the firing of fuel gas with a H_2S content of 200 ppmv in characterizing their estimated SO_2 emissions from Monopod Platform. This assumption is partially representative when considering the historic H_2S content of fired fuel gas reported through test data. More specifically, several high fuel gas H_2S values were reported during the last decade that are attributable to novel exogeneous factors of influence. Samples recorded in recent years, however, demonstrate a trend in the H_2S content of fired fuels that fall closer to Hilcorp's underlying gaseous fuel sulfur assumption, which is reflected in the significant decreases of actual SO_2 emissions. It is worth noting that EU 26, a 4,400 hp fuel gas-fired turbine, is included in the current EU inventory for the stationary source, but it has thus far not been installed for operation. Enforceable conditions have, nevertheless, been included in the current permit constraining the H_2S content of fuel gas fired in this EU.

In an e-mail response to ADEC on March 10, 2021, Hilcorp provided an analytically supported cost estimate for solid scavenging sweetening controls installed on King Salmon platform, assumed to be representative of their Cook Inlet platforms. ADEC notes that the installation and operation of on-platform post-combustion controls is anticipated to be economically impractical due to considerably higher costs relative sweetening units. Hilcorp's results indicate an estimated cost of $24,000-per-ton of SO_2 removal, which is unlikely to be cost effective even by half, based on a review by ADEC staff. ADEC notes the following in support of this position:

The installation of pre-combustion controls on Hilcorp's platforms is anticipated to be technically infeasible due to size and weight of scavenging vessel, space constraints, and strict weight balance requirements of platforms. Were such systems installed, however, solid scavenging sweetening units are typically more cost effective than liquid scavenging units through a review of relevant BACT decisions; these units were the subject of scrutiny for this assessment. Implementing SO_2 sweetening controls would necessitate disposal of sweetening vessel condensate waste. While reductions in SO_2 emissions are possible, this approach externalizes pollutant impacts to liquid or solid waste streams of unknown environmental impact. Moreover, the relative anthropogenic contribution of platforms to visibility impacts in distant Class I areas unlikely to be meaningfully reduced even with significant reductions in platform SO_2 emissions.

Retrofit efforts would be required to install pre-combustion controls on-platform. The costs of such efforts are imbued with significant uncertainty and would entail regular flights for design, construction, and inspection staff as platform lodging is not available for these workers. Such an effort would impact both the economic feasibility of installation work and also generate externalized transportation-borne emissions. Similarly, multiple sweetening vessels would be employed in rotation given the need to regularly recharge treatment media. The handling and transportation of these vessels would be economically prohibitive and also generate externalized transportation-borne emissions via marine vessel use.

It is worth noting that the cost of on-platform electricity generation is typically greater than that of on-shore generation. Therefore, the economic feasibility of on-platform treatment options is less cost-effective by relative comparison. Moreover, realistic levels of control fall below 100-percent in application. The cost effectiveness of a particular control regime, even at high levels of control, are of questionable benefit on platforms that demonstrate relatively low emissions of SO_2.

ADEC, upon consideration of the former limited analysis, concludes that Hilcorp is employing the most practical and effective control regime for their SO_2 emissions at the Monopod Platform stationary source. Said regime broadly entails the firing of low sulfur fuels at the source as enforced by permit condition. The installation and use of additional pre- or post-combustion SO_2 controls are not anticipated to yield meaningful reductions in actual SO_2 emissions and are considered economically impractical on a case-specific basis. ADEC will continue to monitor the SO_2 emissions from this source to ensure that there are no increases that would adversely impact ongoing RH efforts.

i. Hilcorp Alaska, LLC: Grayling Platform

Grayling Platform is owned and operated by Hilcorp, and Hilcorp is the permittee for the stationary source’s Title V Operating Permit, AQ0069TVP03 Revision 1. The SIC code for this stationary source is 1311 – Crude Petroleum and Natural Gas. Grayling Platform is an offshore crude oil and gas production platform located approximately eight kilometers from the western shore of Alaska’s Cook Inlet. Operation of the stationary source yields crude oil, produced water, and natural gas. Produced liquids are processed using on-site separators, and the oil is delivered through an underwater pipeline to the Trading Bay Production Facility. The natural gas is separately delivered by pipeline to the Cook Inlet gas gathering system for sale. The Grayling Platform EU inventory consists of multiple turbines and engines for both power generation and gas compression. Other units are present at the source, which include engine generators, boilers, heaters, flares, and a glycol regenerator.

These EUs are listed in Table III.K.13.F-A16.

Table III.K.13.F-A16 Grayling Platform Emissions Unit Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Construction Date
1	Solar Centaur T4500	#1 Bingham WF Pump Drive	4,500 hp	Fuel Gas	1986
3	Solar Centaur T4500	#2 Bingham WF Pump Drive	4,500 hp	Fuel Gas	1989
4	Solar Centaur T4500	West Compressor Drive	4,500 hp	Fuel Gas	1975
14	Solar Saturn TI200	Oil Shipping Pump Drive	1,100 hp	Fuel Gas	1968
15	Solar Saturn TI200	# 1 AC Gen. Drive	800 kW	Fuel Gas	1969
16	Solar Saturn TI200	# 2 AC Gen. Drive	800 kW	Fuel Gas	1968
17	Solar Saturn TI200	# 3 AC Gen. Drive	750 kW	Fuel Gas	1969
18	Solar Saturn TI200	# 4 AC Gen. Drive	800 kW	Fuel Gas	1971
19	Continental Boiler	#1 Hp Glycol Water Heater	7.3 MCF/hr	Fuel Gas	1967
20	Continental Boiler	#2 Hp Glycol Water Heater	7.3 MCF/hr	Fuel Gas	1967
24	Cat 3406 Engine	West Crane	340 hp	Liquid Fuel	1985
25	Cat 3208 Engine	East Crane-Skagit	250 hp	Liquid Fuel	1991
26a	Detroit Diesel Series 60 6063HV35	Emergency AC Gen. Drive	685 hp	Liquid Fuel	2010
27	Cat D-330C Engine	Fire Water Pump Drive	85 hp	Liquid Fuel	1970
28	Flare (South)	Flare (Emergency Operation 14 MMscf/day)	3.942 MMscf/yr (pilot/purge operation)	Fuel Gas	1967
29	Flare (SW)	Flare (Emergency Operation 14 MMscf/day)		Fuel Gas	1967
30	Glycol Regenerator	TEG Dehydration Unit	13 MMscf raw gas/day	n/a	Pre-1996
31	Solar Taurus 60 T-7300S	Turbine	78.6 MMBtu/hr (5.2 MW)	Fuel Gas	2003
n/a	Clayton ROG-60-1 Boiler	Boiler	2.5 MMBtu/hr	Fuel Gas	n/a
n/a	Portable Space Heaters	Heaters	8 MMBtu/hr	Liquid Fuel	n/a

n/a	Clayton Sigma Fire	Steam Generator/Boiler	50 bhp	Fuel Gas	n/a
n/a	Diesel Fuel Tank	Tank	3,480 bbl	Liquid Fuel	n/a
n/a	Crude Oil Tank	Tank	2,100 bbl	Liquid Fuel	n/a
n/a	Crude Oil Tank	Tank	2,100 bbl	Liquid Fuel	n/a

Table Notes: The boilers, heaters, and tanks are considered insignificant EUs for the purposes of Title V permitting.

ADEC staff drew upon reported emissions data from 2015 through 2019 to determine the sources and scale of SO_2 emissions at Grayling Platform. A review of Hilcorp's application materials and current permitting provides a characterization of the sulfur content of fuels fired at the source as well as the current SO_2 PTE.

A summary of the former information is provided in Table III.K.13.F-A17.

Table III.K.13.F-A17 Grayling Platform SO_2 Emissions

Calendar Year	Avg. H_2S Content of Fired Fuel Gas (ppmv)	Max Sulfur Content of Fired Liquid Fuel (ppmw)	Actual SO_2 Emissions (tons)	Potential SO_2 Emissions (tons)
2019	375.0	15	44.2	96.1
2018	200.0	15	23.7	
2017	225.0	15	21.7	
2016	140.6	15	21.1	
2015	216.3	15	37.9	

A review of the application materials for AQ0069TVP03, and its most current revision, indicates that the emissions of SO_2 from Grayling Platform are estimated, in part, assuming the firing of liquid fuels with a sulfur content of 500 ppmw. Hilcorp, however, certifies through compliance reporting that ULSD is exclusively used in the liquid fuel-fired EUs at Grayling Platform, thus yielding actual emissions of the pollutant that are significantly lower. ADEC notes that the emissions of SO_2 at the stationary source are principally driven by the fuel gas-fired EUs; nearly a quarter of the former emissions are attributable to the two emergency flares, which, like most equipment at the source, are conservatively assumed to operate 8,760 hours annually. It is worth further noting that actual SO_2 emissions at the source represent approximately one-third to one-quarter of estimated potentials.

Hilcorp has assumed the firing of fuel gas with a H_2S content of 250 ppmv in characterizing their estimated SO_2 emissions from Grayling Platform. This assumption is broadly representative, and often conservative, when considering the H_2S content of fired fuel gas reported through test data. Similarly, the current Title V permit includes enforceable conditions to perform monitoring and mitigative action should SO_2 emissions increase beyond threshold values. This permit also includes a source-wide enforceable limit on the H_2S content of all fired fuel gas set at 400 ppmv, which is mirrored in both the ambient protection requirements carried forward from Minor Permit AQ0069MSS04 and NSPS requirements for the multiple turbine EUs. To actionably promote the firing of fuel gas with a lower H_2S content, Hilcorp also operates pre-combustion

H_2S ‘sweetening’ equipment to treat a portion of recovered gases, which are subsequently blended with onshore fuel gas for use in the platform EUs.

In an e-mail response to ADEC on March 10, 2021, Hilcorp provided an analytically supported cost estimate for solid scavenging sweetening controls installed on King Salmon platform, assumed to be representative of their Cook Inlet platforms. ADEC notes that the installation and operation of on-platform post-combustion controls is anticipated to be economically impractical due to considerably higher costs relative sweetening units. Hilcorp’s results indicate an estimated cost of $24,000-per-ton of SO_2 removal, which is unlikely to be cost effective even by half, based on a review by ADEC staff. ADEC notes the following in support of this position:

The installation of pre-combustion controls on Hilcorp’s platforms is anticipated to be technically infeasible due to size and weight of scavenging vessel, space constraints, and strict weight balance requirements of platforms. Were such systems installed, however, solid scavenging sweetening units are typically more cost effective than liquid scavenging units through a review of relevant BACT decisions; these units were the subject of scrutiny for this assessment. Implementing SO_2 sweetening controls would necessitate disposal of sweetening vessel condensate waste. While reductions in SO_2 emissions are possible, this approach externalizes pollutant impacts to liquid or solid waste streams of unknown environmental impact. Moreover, the relative anthropogenic contribution of platforms to visibility impacts in distant Class I areas unlikely to be meaningfully reduced even with significant reductions in platform SO_2 emissions.

Retrofit efforts would be required to install pre-combustion controls on-platform. The costs of such efforts are imbued with significant uncertainty and would entail regular flights for design, construction, and inspection staff as platform lodging is not available for these workers. Such an effort would impact both the economic feasibility of installation work and also generate externalized transportation-borne emissions. Similarly, multiple sweetening vessels would be employed in rotation given the need to regularly recharge treatment media. The handling and transportation of these vessels would be economically prohibitive and also generate externalized transportation-borne emissions via marine vessel use.

It is worth noting that the cost of on-platform electricity generation is typically greater than that of on-shore generation. Therefore, the economic feasibility of on-platform treatment options is less cost-effective by relative comparison. Moreover, realistic levels of control fall below 100-percent in application. The cost effectiveness of a particular control regime, even at high levels of control, are of questionable benefit on platforms that demonstrate relatively low emissions of SO_2.

ADEC, upon consideration of the former limited analysis, concludes that Hilcorp is employing the most practical and effective control regime for their SO_2 emissions at the Grayling Platform stationary source. Said regime broadly entails the firing of low sulfur fuels at the source, enforced by both permit condition and the use of pre-combustion control equipment. The installation and use of additional pre- or post-combustion SO_2 controls are not anticipated to yield meaningful reductions in actual SO_2 emissions and are considered economically impractical on a case-specific basis. ADEC will continue to monitor the SO_2 emissions from this source to ensure that there are no increases that would adversely impact ongoing RH efforts.

j. Hilcorp Alaska, LLC: Dolly Varden Platform

Dolly Varden Platform is owned and operated by Hilcorp, and Hilcorp is the permittee for the stationary source's Title V Operating Permit, AQ0060TVP04. The SIC code for this stationary source is 1311 – Crude Petroleum and Natural Gas. Dolly Varden Platform is an offshore crude oil and gas exploration and production platform located in Alaska's Cook Inlet. Operation of the stationary source yields crude oil, produced water, and natural gas. Produced liquids are processed using on-site separators and subsequently delivered by underwater pipeline to the Granite Point Tank Farm; produced fuel gas is also fired or flared in platform EUs. The Dolly Varden Platform EU inventory consists of multiple turbines and engines for both power generation and gas compression. Other units are present at the source, which include engine generators, flares, boilers, heaters, and liquid fuel storage tanks.

These EUs are listed in Table III.K.13.F-A18.

Table III.K.13.F-A18 Dolly Varden Platform Emissions Unit Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Construction Date
1	Solar Saturn T-1200 Turbine	Solar Pump Drive #1 Fuel Gas	1,200 Hp	Fuel Gas	1969
2	Solar Saturn T-1200 Turbine	Solar Pump Drive #2 Fuel Gas	1,200 Hp	Fuel Gas	1969
5	Solar Saturn T-1200 Turbine	Solar Pump Drive #5 Fuel Gas	1,200 Hp	Fuel Gas	1969
6	Solar Saturn T-1200 Turbine	Solar Pump Drive #6 Fuel Gas	1,200 Hp	Fuel Gas	1969
7	Solar Saturn T-1200 Turbine	Solar Pump Drive #7 Fuel Gas	1,200 Hp	Fuel Gas	1968
8	Solar Saturn T-1200 Turbine	AC #1 Generator Drive Fuel Gas	1,200 Hp	Fuel Gas	1969
9	Solar Saturn T-1200 Turbine	AC #2 Generator Drive Fuel Gas	1,200 Hp	Fuel Gas	1970
10	Solar Saturn T-1200 Turbine	AC #3 Generator Drive Fuel Gas/Diesel	1,200 Hp	Dual Fuel	1970
12	Solar Centaur T-4500 Turbine	Compressor Drive Fuel Gas	4,500 Hp	Fuel Gas	1985
13	Solar Centaur T-5900 Turbine	AC #6 ESP Generator Fuel Gas	4,270 kW	Fuel Gas	2002
16	Bryan Boiler	Glycol Boiler #1 Fuel Gas	8.5 MMBtu/hr	Fuel Gas	2006

17	Bryan Boiler	Glycol Boiler #2 Fuel Gas	8.5 MMBtu/hr	Fuel Gas	2006
20	Detroit Diesel 8V71 Engine (NE)	East Skagit Crane Diesel	350 Hp	Liquid Fuel	1989
21	Detroit Diesel 8V71 Engine (SW)	West Skagit Crane Diesel	350 Hp	Liquid Fuel	1989
22	Detroit Diesel Engine	Fire Pump Drive P-3 Diesel	405 kW	Liquid Fuel	1994
23	Detroit Diesel Engine	Detroit Backup Generator Diesel	400 kW	Liquid Fuel	1994
24	Caterpillar 3306B Engine	Air Compressor Driver Diesel	265 bHp	Liquid Fuel	2003
25	Flare (SF/HP/LP) and Pilot	Safety/Operating Flares Fuel Gas	570 MMscf/yr	Fuel Gas	1995
26	Solar Centaur 50 Turbine	AC #7 SoLoNOx Turbine Fuel Gas	5.65 MW	Fuel Gas	2003
K1	Hydraulic Power Unit	Detroit Diesel/ Series DDEC IV Engine	850 Hp	Liquid Fuel	TBD
K2	Hydraulic Power Unit	Detroit Diesel/ Series DDEC IV Engine	850 Hp	Liquid Fuel	TBD
K3	Light Plant Generator	Detroit Diesel/ Series 60 Engine	600 Hp	Liquid Fuel	TBD
K4	Light Plant Generator	Detroit Diesel/ Series 60 Engine	600 Hp	Liquid Fuel	TBD
K5	Portable Hydraulic Gen.	Engine (make/model unknown)	101 Hp	Liquid Fuel	TBD
K6	Boiler	Volcano Boiler	3.6 MMBtu/hr	Liquid Fuel	TBD
K7	Boiler	Volcano Boiler	3.6 MMBtu/hr	Liquid Fuel	TBD
n/a	Bryan Boiler	Steam Boiler #3 - Gas	4.2 MMBtu/hr	Fuel Gas	n/a
n/a	Burnham PF-510 Boiler #4	MSM Glycol Boiler #4 - Gas/Diesel	2.033 MMBtu/hr	Dual Fuel	n/a
n/a	Burnham PF-510 Boiler #5	MSM Glycol Boiler #5 - Gas/Diesel	2.033 MMBtu/hr	Dual Fuel	n/a
n/a	Hotsey Portable Pressure Washer	Portable Boiler - Diesel	197 Btu/hr	Liquid Fuel	n/a
n/a	Portable Heaters	Portable Heaters (Each less than 1.7 MMBtu/hr)	4.0 MMBtu/hr	Liquid Fuel	n/a
n/a	Crane Pedestal Fuel Storage Tanks	Storage Tanks	Various	Liquid Fuel	n/a
n/a	Diesel Storage Tank	Diesel Storage Tank	49,980 gallons	Liquid Fuel	n/a

n/a	Diesel Day Tank	Diesel Storage Tank	860 gallon	Liquid Fuel	n/a
n/a	Diesel Reserve Tank	Diesel Storage Tank	187 gallons	Liquid Fuel	n/a
n/a	Emergency Generator Tank	Diesel Storage Tank	273 gallons	Liquid Fuel	n/a
n/a	P-3 Fire Water Generator Tank	Diesel Storage Tank	273 gallons	Liquid Fuel	n/a

Table Notes: The heaters, (non-ID) boilers, pressure washer, and tanks are considered insignificant EUs for the purposes of Title V permitting.

ADEC staff drew upon reported emissions data from 2015 through 2019 to determine the sources and scale of SO_2 emissions at Dolly Varden Platform. A review of Hilcorp's application materials and current permitting provides a characterization of the sulfur content of fuels fired at the source as well as the current SO_2 PTE. A summary of the former information is provided in Table III.K.13.F-A19.

Table III.K.13.F-A19 Dolly Varden Platform SO_2 Emissions

Calendar Year	Highest H_2S Content of Fired Fuel Gas in all other EUs (ppmv)	Highest H_2S Content of Fired Fuel Gas in EUs 13 & 26 (ppmv)	Max Sulfur Content of Fired Liquid Fuel (ppmw)	Actual SO_2 Emissions (tons)	Potential SO_2 Emissions (tons)
2019	1,075	100	15	96.3	442.0
2018	980	125	15	92.1	
2017	1,200	Not Reported	15	152.8	
2016	1,100	Not Reported	15	151.3	
2015	1,600	Not Reported	15	252.8	

A review of the application materials for AQ0060TVP04 indicates that the emissions of SO_2 from Dolly Varden Platform are estimated, in part, assuming the firing of liquid fuels with a sulfur content of 500 ppmw. Hilcorp, however, certifies through compliance reporting that ULSD is exclusively used in the liquid fuel-fired EUs at Dolly Varden Platform, thus yielding actual emissions of the pollutant that are significantly lower. ADEC notes that over 90-perent of the estimated emissions of SO_2 at the stationary source are driven by the fuel gas-fired compressor and generator EUs in addition to the flare, which, like most equipment at the source, are conservatively assumed to operate 8,760 hours annually; the flare is conservatively estimated to fire 570 MMscf/yr. It is worth further noting that actual SO_2 emissions at the source are considerably lower than estimated potentials by approximately one-third to one-quarter.

Hilcorp has assumed the firing of fuel gas with a H_2S content of 2,000 ppmv in characterizing their estimated SO_2 emissions from major emissions-generating EUs at Dolly Varden Platform. This assumption is broadly representative when considering the H_2S content of fired fuel gas reported through recent test data. The current Title V permit also includes enforceable conditions limiting the H_2S content of fired fuel gas in EUs 13 and 26 to no greater than 1,000 ppmv.

Hilcorp has indicated that the Dolly Varden platform is equipped with pre-combustion H_2S 'sweetening' equipment to treat a portion of recovered gases, which are subsequently blended with onshore fuel gas for use in the platform EUs. However, in a February 16, 2021, response to request for information by ADEC, they assert that this equipment is "…out of service and would require extensive operational testing and potential upgrades before it could be returned to service". ADEC has requested further detail from Hilcorp regarding an economic overview of fuel gas sulfur treatment. This information will allow ADEC to establish a position on the adequacy of existing SO_2 controls and, as warranted, recommend the installation and/or operation of such controls, whether existing or new, to actionably promote the firing of fuel gas with a lower H_2S content.

In an e-mail response to ADEC on March 10, 2021, Hilcorp provided an analytically supported cost estimate for solid scavenging sweetening controls installed on King Salmon platform, assumed to be representative of their Cook Inlet platforms. ADEC notes that the installation and operation of on-platform post-combustion controls is anticipated to be economically impractical due to considerably higher costs relative sweetening units. Hilcorp's results indicate an estimated cost of $24,000-per-ton of SO_2 removal, which is unlikely to be cost effective even by half based on a review by ADEC staff. ADEC notes the following in support of this position:

The installation of pre-combustion controls on Hilcorp's platforms is anticipated to be technically infeasible due to size and weight of scavenging vessel, space constraints, and strict weight balance requirements of platforms. Were such systems installed, however, solid scavenging sweetening units are typically more cost effective than liquid scavenging units through a review of relevant BACT decisions; these units were the subject of scrutiny for this assessment. Implementing SO_2 sweetening controls would necessitate disposal of sweetening vessel condensate waste. While reductions in SO_2 emissions are possible, this approach externalizes pollutant impacts to liquid or solid waste streams of unknown environmental impact. Moreover, the relative anthropogenic contribution of platforms to visibility impacts in distant Class I areas unlikely to be meaningfully reduced even with significant reductions in platform SO_2 emissions.

Retrofit efforts would be required to install pre-combustion controls on-platform. The costs of such efforts are imbued with significant uncertainty and would entail regular flights for design, construction, and inspection staff as platform lodging is not available for these workers. Such an effort would impact both the economic feasibility of installation work and also generate externalized transportation-borne emissions. Similarly, multiple sweetening vessels would be employed in rotation given the need to regularly recharge treatment media. The handling and transportation of these vessels would be economically prohibitive and also generate externalized transportation-borne emissions via marine vessel use.

It is worth noting that the cost of on-platform electricity generation is typically greater than that of on-shore generation. Therefore, the economic feasibility of on-platform treatment options is less cost-effective by relative comparison. Moreover, realistic levels of control fall below 100-

percent in application. The cost effectiveness of a particular control regime, even at high levels of control, are of questionable benefit on platforms that demonstrate relatively low emissions of SO_2.

ADEC, upon consideration of the former limited analysis, but notwithstanding its outstanding request for an economic overview of SO_2 controls, tentatively concludes that Hilcorp is employing the most practical and effective control regime for their SO_2 emissions at the Dolly Varden Platform stationary source. Said regime broadly entails the firing of low sulfur fuels at the source, enforced by both permit condition and the probable use of existing pre-combustion control equipment. The installation and use of additional pre- or post-combustion SO_2 controls are not anticipated to yield meaningful reductions in actual SO_2 emissions and are considered economically impractical on a case-specific basis. ADEC will continue to monitor the SO_2 emissions from this source to ensure that there are no increases that would adversely impact ongoing RH efforts.

k. Hilcorp Alaska, LLC: King Salmon Platform

King Salmon Platform is owned and operated by Hilcorp, and Hilcorp is the permittee for the stationary source's Title V Operating Permit, AQ0068TVP04. The SIC code for this stationary source is 1311 – Crude Petroleum and Natural Gas. King Salmon Platform is an offshore crude oil and gas exploration and production platform located in Alaska's Cook Inlet. Operation of the stationary source yields crude oil, produced water, and natural gas. Produced liquids are processed using on-site separators and subsequently delivered by underwater pipeline to the Trading Bay Production Facility for sale; produced fuel gas is also fired or flared in platform EUs. The King Salmon Platform EU inventory consists of multiple turbines and engines for both power generation and gas compression. Other units are present at the source, which include engine generators, boilers, heaters, and liquid hydrocarbon storage tanks.

These EUs are listed in Table III.K.13.F-A20.

Table III.K.13.F-A20 King Salmon Platform Emissions Unit Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Construction Date
1	Solar Centaur T4000	Waterflood Pump Drive (NG)	3,830 hp	Fuel Gas	1981
4	Solar Centaur 40-T4700S	ESP Generator-SoLoNOx (NG)	3,320 hp	Fuel Gas	2002
5	Solar Saturn T1100	York Compressor Drive (NG)	1,100 hp	Fuel Gas	1969
6	Ruston TA-1750 Turbine	AC Generator Drive #1 (NG/Diesel)	1,250 kW	Fuel Gas	1969
7	Ruston TA-1750 Turbine	AC Generator Drive #1 (NG/Diesel)	1,250 kW	Fuel Gas	1969
11	GM 16-645E1	Engine Drilling Generator #2 (Diesel)	1,250 kW	Liquid Fuel	1969

12	Detroit Diesel 671 Engine	Clyde MC6000 Crane East (Diesel)	200 hp	Liquid Fuel	1967
13	Detroit Diesel 671 Engine	Clyde MC6000 Crane West (Diesel)	200 hp	Liquid Fuel	1967
14	John Deere Engine	Emergency Fire Pump Drive (Diesel)	175 hp	Liquid Fuel	1967
15	Caterpillar 3304 Engine	Standby AC Gen. Drive (Diesel)	135 hp (90 kW)	Liquid Fuel	1967
18	William & Davis 200-767	Boiler No. 1 (NG)	8.4 MMBtu/hr	Fuel Gas	1976
19	William & Davis 200-767	Boiler No. 2 (NG)	8.4 MMBtu/hr	Fuel Gas	1976
20	Deutz Model F3L912	Air Compressor Engine	52 hp	Liquid Fuel	1986
21	Cummins 6A3-4-G1	Emergency Generator Engine	50 hp	Liquid Fuel	1991
n/a	Clayton ROG Steam Generator	Boiler	4.2 MMBtu/hr	Fuel Gas	n/a
n/a	Bruest Heater	Portable Heaters (Each less than 1.7 MMBtu/hr)	0.072 MMBtu/hr	Fuel Gas	n/a
n/a	Bruest Heater	Portable Heaters (Each less than 1.7 MMBtu/hr)	0.072 MMBtu/hr	Fuel Gas	n/a
n/a	Bruest Heater	Portable Heaters (Each less than 1.7 MMBtu/hr)	0.072 MMBtu/hr	Fuel Gas	n/a
n/a	Bruest Heater	Portable Heaters (Each less than 1.7 MMBtu/hr)	0.072 MMBtu/hr	Fuel Gas	n/a
n/a	Bruest Heater	Portable Heaters (Each less than 1.7 MMBtu/hr)	0.072 MMBtu/hr	Fuel Gas	n/a
n/a	Air Compressor Engine	Engine	52 hp	Liquid Fuel	n/a
n/a	Emergency Generator Engine	Engine	50 hp	Liquid Fuel	n/a
n/a	Portable Heaters	Portable Heaters (Each less than 1.7 MMBtu/hr)	5.0 MMBtu/hr	Fuel Gas	n/a
n/a	West Escape Capsule	Escape Capsule	35 hp	Liquid Fuel	n/a
n/a	East Escape Capsule	Escape Capsule	35 hp	Liquid Fuel	n/a
n/a	Rescue Boat No. 1	Rescue Boat	110 hp	Liquid Fuel	n/a
n/a	Miscellaneous Fuel Storage Tanks	Storage Tank	Various	Liquid Fuel	n/a
n/a	Miscellaneous Hydrocarbon Storage Tanks	Storage Tank	Various	Liquid Fuel	n/a
n/a	Miscellaneous AC Refrigeration, and	n/a	Various	Liquid Fuel	n/a

	Fire Suppression Units				
n/a	Wastewater Treatment Tanks	Storage Tank	Various	Liquid Fuel	n/a
n/a	Portable Washer	Portable Washer	15 hp	Liquid Fuel	n/a
n/a	Portable Welding Generator	Portable Welding Generator	20 kW	Liquid Fuel	n/a

Table Notes: The units with EU IDs 'n/a' are considered insignificant EUs for the purposes of Title V permitting.

ADEC staff drew upon reported emissions data from 2015 through 2019 to determine the sources and scale of SO_2 emissions at King Salmon Platform. A review of Hilcorp's application materials and current permitting provides a characterization of the sulfur content of fuels fired at the source as well as the current SO_2 PTE.

A summary of the former information is provided in Table III.K.13.F-A21.

Table III.K.13.F-A21 King Salmon Platform SO_2 Emissions

Calendar Year	Highest H_2S Content of Fired Fuel Gas (ppmv)	Max Sulfur Content of Fired Liquid Fuel (ppmw)	Actual SO_2 Emissions (tons)	Potential SO_2 Emissions (tons)
2019	450	15	54.7	345.7
2018	775.0	15	118.7	
2017	900.0	15	118.7	
2016	1,000.0	15	118.2	
2015	800.0	15	Approx. 118	

Table Notes: Actual emissions in 2015 and potential emissions are estimated from other reported criteria pollutant emissions.

A review of the application materials for AQ0068TVP04 indicates that the emissions of SO_2 from King Salmon Platform are estimated, in part, assuming the firing of liquid fuels with a sulfur content of 500 ppmw. Hilcorp, however, certifies through compliance reporting that ULSD is exclusively used in the liquid fuel-fired EUs at King Salmon Platform, thus yielding actual emissions of the pollutant that are significantly lower. ADEC notes that over 80-perent of the estimated emissions of SO_2 at the stationary source are driven by the fuel gas-fired compressor and generator EUs in addition to the flare, which, like most equipment at the source, are conservatively assumed to operate 8,760 hours annually; the flare is conservatively estimated to fire 8.76 MMscf/yr. It is worth further noting that actual SO_2 emissions at the source are considerably lower than estimated potentials by approximately one-third or more.

Hilcorp has assumed the firing of fuel gas with a H_2S content of 2,000 ppmv in characterizing their estimated SO_2 emissions from major emissions-generating EUs at King Salmon Platform. This assumption is broadly representative and conservative when considering the H_2S content of fired fuel gas reported through recent test data. The current Title V permit also includes enforceable conditions limiting the H_2S content of fired fuel gas to no greater than 1,100 ppmv

Hilcorp, in a response to ADEC's request for additional information, has indicated that the King Salmon platform is not equipped with pre-combustion H_2S 'sweetening' equipment to treat a portion of recovered gases, which are subsequently blended with onshore fuel gas for use in the platform EUs. However, following Hilcorp's February 16, 2021, response to this request, ADEC has requested further detail from Hilcorp regarding an economic overview of fuel gas sulfur treatment. This information will allow ADEC to establish a position on the feasibility of installing SO_2 controls, such as those installed on Grayling, Dolly Varden, and Steelhead platforms and, as warranted, recommend the installation and/or operation of such controls to actionably promote the firing of fuel gas with a lower H_2S content.

In an e-mail response to ADEC on March 10, 2021, Hilcorp provided an analytically supported cost estimate for solid scavenging sweetening controls installed on King Salmon platform, assumed to be representative of their Cook Inlet platforms. ADEC notes that the installation and operation of on-platform post-combustion controls is anticipated to be economically impractical due to considerably higher costs relative sweetening units. Hilcorp's results indicate an estimated cost of $24,000-per-ton of SO_2 removal, which is unlikely to be cost effective even by half, based on a review by ADEC staff. ADEC notes the following in support of this position:

The installation of pre-combustion controls on Hilcorp's platforms is anticipated to be technically infeasible due to size and weight of scavenging vessel, space constraints, and strict weight balance requirements of platforms. Were such systems installed, however, solid scavenging sweetening units are typically more cost effective than liquid scavenging units through a review of relevant BACT decisions; these units were the subject of scrutiny for this assessment. Implementing SO_2 sweetening controls would necessitate disposal of sweetening vessel condensate waste. While reductions in SO_2 emissions are possible, this approach externalizes pollutant impacts to liquid or solid waste streams of unknown environmental impact. Moreover, the relative anthropogenic contribution of platforms to visibility impacts in distant Class I areas unlikely to be meaningfully reduced even with significant reductions in platform SO_2 emissions.

Retrofit efforts would be required to install pre-combustion controls on-platform. The costs of such efforts are imbued with significant uncertainty and would entail regular flights for design, construction, and inspection staff as platform lodging is not available for these workers. Such an effort would impact both the economic feasibility of installation work and also generate externalized transportation-borne emissions. Similarly, multiple sweetening vessels would be employed in rotation given the need to regularly recharge treatment media. The handling and transportation of these vessels would be economically prohibitive and also generate externalized transportation-borne emissions via marine vessel use.

It is worth noting that the cost of on-platform electricity generation is typically greater than that of on-shore generation. Therefore, the economic feasibility of on-platform treatment options is less cost-effective by relative comparison. Moreover, realistic levels of control fall below 100-

percent in application. The cost effectiveness of a particular control regime, even at high levels of control, are of questionable benefit on platforms that demonstrate relatively low emissions of SO_2.

ADEC, upon consideration of the former limited analysis, but notwithstanding its outstanding request for an economic overview of SO_2 controls, tentatively concludes that Hilcorp is employing the most practical and effective control regime for their SO_2 emissions at the King Salmon Platform stationary source. Said regime broadly entails the firing of low sulfur fuels at the source, enforced by both permit condition and the potential use of pre-combustion control equipment should it be economically practical. The installation and use of additional pre- or post-combustion SO_2 controls beyond that discussed are not anticipated to yield meaningful reductions in actual SO_2 emissions and are considered economically impractical on a case-specific basis. ADEC will continue to monitor the SO_2 emissions from this source to ensure that there are no increases that would adversely impact ongoing RH efforts.

l. Hilcorp Alaska, LLC: Steelhead Platform

Steelhead Platform is owned and operated by Hilcorp, and Hilcorp is the permittee for the stationary source's Title V Operating Permit, AQ0009TVP04 Revision 1. The SIC code for this stationary source is 1311 – Crude Petroleum and Natural Gas. Steelhead Platform is an offshore crude oil and gas exploration and production platform located in Alaska's Cook Inlet. Operation of the stationary source yields crude oil, produced water, and natural gas. Produced liquids are processed using on-site separators and subsequently delivered by underwater pipeline to the Trading Bay Production Facility for sale; produced fuel gas is also fired or flared in platform EUs. The Steelhead Platform EU inventory consists of multiple turbines and engines for both power generation and gas compression. Other units are present at the source, which include engine generators, flares, heaters, liquid fuel storage tanks, and glycol dehydrators.

These EUs are listed in Table III.K.13.F-A22.

Table III.K.13.F-A22 Steelhead Platform Emissions Unit Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Construction Date
1	Generator A Drive	Allison 501 KB Turbine	41.1 MMBtu/hr	Dual Fuel	1986
2	Generator B Drive	Allison 501 KB Turbine	41.1 MMBtu/hr	Dual Fuel	1986
3	Generator C Drive	Allison 501 KB Turbine	41.1 MMBtu/hr	Fuel Gas	1986
4	C-12 Transport Comp. Drive	Solar Taurus 70-10302S Turbine	10,700 hp	Fuel Gas	1986
5	C-13 Transport Comp. Drive	Solar Taurus T-7000 Turbine	54.9 MMBtu/hr	Fuel Gas	2009
6	Emergency Production Generator Drive	Cat D3516-TA Engine	1,400 hp	Liquid Fuel	1991

7	Standby Drilling Generator Drive	Cat D399 Engine	1,400 hp	Liquid Fuel	1986
8	North Crane Engine	Cat 3408 DITA Engine	450 hp	Liquid Fuel	1986
9	South Crane Engine	Cat 3408 DITA Engine	450 hp	Liquid Fuel	1988
10	NW Fire Pump Drive	Detroit Diesel 12V71 Engine	450 hp	Liquid Fuel	1986
11	SE Fire Pump Drive	Detroit Diesel 12V71 Engine	450 hp	Liquid Fuel	1986
12	North Safety Flare	HP/LP Flare/Pilot	181.5 MMcfd	Fuel Gas	1986
13	South Safety Flare	HP/LP Flare/Pilot	181.5 MMcfd	Fuel Gas	1986
14	Gas Compressor Drive	Solar Saturn T1200 Turbine	1,267 hp	Fuel Gas	1986
15	Gas Compressor Drive	Solar Saturn T1200 Turbine	1,267 hp	Fuel Gas	2008
16	TEG Glycol Dehydration Vent	Glycol Dehydration	n/a	n/a	2008
17	TEG Glycol Dehydration Vent	Glycol Dehydration	n/a	n/a	1987
18	Caterpillar Emergency Air Compressor Engine	Sullair 900	300 hp	Liquid Fuel	2013
n/a	Portable Heaters	Portable Heaters – Each heater has an individual rating of less than 1.7 MMBtu/hr	5.0 MMBtu/hr	Liquid Fuel	1987
n/a	Diesel Storage Tank	Diesel Storage Tank	53,550 gallons	Liquid Fuel	n/a
n/a	Diesel Storage Tank	Diesel Storage Tank	32,130 gallons	Liquid Fuel	n/a
n/a	Diesel Storage Tank	Diesel Storage Tank	26,775 gallons	Liquid Fuel	n/a
n/a	North Pedestal Diesel Storage Tank	Diesel Storage Tank	5,670 gallons	Liquid Fuel	n/a
n/a	South Pedestal Diesel Storage Tank	Diesel Storage Tank	5,670 gallons	Liquid Fuel	n/a
n/a	Cat D399 Drilling Emergency Generator Tank	Diesel Storage Tank	2,200 gallons	Liquid Fuel	n/a
n/a	Cat 3516 Production Emergency Generator Tank	Diesel Storage Tank	500 gallons	Liquid Fuel	n/a

Table Notes: The heaters, and tanks are considered insignificant EUs for the purposes of Title V permitting.

ADEC staff drew upon reported emissions data from 2015 through 2019 to determine the sources and scale of SO_2 emissions at Steelhead Platform. A review of Hilcorp's application materials and current permitting provides a characterization of the sulfur content of fuels fired at the source as well as the current SO_2 PTE.

A summary of the former information is provided in Table III.K.13.F-A23.

Table III.K.13.F-A23 Steelhead Platform SO_2 Emissions

Calendar Year	Highest H_2S Content of Fired Fuel Gas in EUs 12 & 13 (ppmv)	Highest H_2S Content of Fired Fuel Gas in all other EUs (ppmv)	Max Sulfur Content of Fired Liquid Fuel (ppmw)	Actual SO_2 Emissions (tons)	Potential SO_2 Emissions (tons)
2019	961.6	1.5	15	6.7	281.0
2018	524	1.5	15	4.2	
2017	2.5	1,400	15	61.4	
2016	0.8	0.8	15	0.1	
2015	3	3	15	0.5	

A review of the application materials for AQ0009TVP04, and its most current revision, indicates that the emissions of SO_2 from Steelhead Platform are estimated, in part, assuming the firing of liquid fuels with a sulfur content of 250 ppmw. Hilcorp, however, certifies through compliance reporting that ULSD is exclusively used in the liquid fuel-fired EUs at Steelhead Platform, thus yielding actual emissions of the pollutant that are significantly lower. ADEC notes that over 92-perent of the estimated emissions of SO_2 at the stationary source are driven by the fuel gas-fired compressor and generator EUs which, like most equipment at the source, are conservatively assumed to operate 8,760 hours annually. It is worth further noting that actual SO_2 emissions at the source are considerably lower estimated potentials, notwithstanding in increase in 2017 attributable to novel exogeneous factors of influence.

Hilcorp has assumed the firing of fuel gas with a H_2S content of 2,000 ppmv in characterizing their estimated SO_2 emissions from major emissions-generating EUs at Steelhead Platform. Notwithstanding the atypical firing of sour fuel gas in select EUs during recent years, this assumption is broadly conservative when considering the relatively low H_2S content of fired fuel gas reported through recent test data. Similarly, the current Title V permit includes enforceable conditions limiting the H_2S content of fired fuel to no greater than 350 ppmv and requirements to perform monitoring and mitigative action should its content exceed 298 ppmv. The permit also includes owner requested limits on SO_2 emissions to avoid prevention of significant deterioration review. To actionably promote the firing of fuel gas with a lower H_2S content, Hilcorp also operates pre-combustion H_2S 'sweetening' equipment to treat a portion of recovered gases, which are subsequently blended with onshore fuel gas for use in the platform EUs.

In an e-mail response to ADEC on March 10, 2021, Hilcorp provided an analytically supported cost estimate for solid scavenging sweetening controls installed on King Salmon platform, assumed to be representative of their Cook Inlet platforms. ADEC notes that the installation and operation of on-platform post-combustion controls is anticipated to be economically impractical due to considerably higher costs relative sweetening units. Hilcorp's results indicate an estimated cost of $24,000-per-ton of SO_2 removal, which is unlikely to be cost effective even by half, based on a review by ADEC staff. ADEC notes the following in support of this position:

The installation of pre-combustion controls on Hilcorp's platforms is anticipated to be technically infeasible due to size and weight of scavenging vessel, space constraints, and strict weight balance requirements of platforms. Were such systems installed, however, solid scavenging sweetening units are typically more cost effective than liquid scavenging units through a review of relevant BACT decisions; these units were the subject of scrutiny for this assessment. Implementing SO_2 sweetening controls would necessitate disposal of sweetening vessel condensate waste. While reductions in SO_2 emissions are possible, this approach externalizes pollutant impacts to liquid or solid waste streams of unknown environmental impact. Moreover, the relative anthropogenic contribution of platforms to visibility impacts in distant Class I areas unlikely to be meaningfully reduced even with significant reductions in platform SO_2 emissions.

Retrofit efforts would be required to install pre-combustion controls on-platform. The cost of such efforts are imbued with significant uncertainty and would entail regular flights for design, construction, and inspection staff as platform lodging is not available for these workers. Such an effort would impact both the economic feasibility of installation work and also generate externalized transportation-borne emissions. Similarly, multiple sweetening vessels would be employed in rotation given the need to regularly recharge treatment media. The handling and transportation of these vessels would be economically prohibitive and also generate externalized transportation-borne emissions via marine vessel use.

It is worth noting that the cost of on-platform electricity generation is typically greater than that of on-shore generation. Therefore, the economic feasibility of on-platform treatment options is less cost-effective by relative comparison. Moreover, realistic levels of control fall below 100-percent in application. The cost effectiveness of a particular control regime, even at high levels of control, are of questionable benefit on platforms that demonstrate relatively low emissions of SO_2.

ADEC, upon consideration of the former limited analysis, concludes that Hilcorp is employing the most practical and effective control regime for their SO_2 emissions at the Steelhead Platform stationary source. Said regime broadly entails the firing of low sulfur fuels at the source, enforced by both permit condition and the use of pre-combustion control equipment. The installation and use of additional pre- or post-combustion SO_2 controls are not anticipated to yield meaningful reductions in actual SO_2 emissions and are considered economically impractical on a case-specific basis. ADEC will continue to monitor the SO_2 emissions from this source to ensure that there are no increases that would adversely impact ongoing RH efforts.

m. BlueCrest Alaska Operating, LLC: Cosmopolitan Project

The Cosmopolitan Project is owned and operated by Bluecrest Alaska Operating, LLC (Bluecrest), and Bluecrest is the permittee for the stationary source's Minor Permit AQ1385MSS04. The SIC code for this stationary source is 1311 – Crude Petroleum and Natural Gas. The stationary source performs oil and gas extraction with the current facility designed to process up to 20,000 barrels of oil per day and up to 60 million cubic feet of gas per day.

The stationary source's EUs are listed below in Table III.K.13.F-A24 and Table III.K.13.F-A25.

Table III.K.13.F-A24 Cosmopolitan Project Onshore Emission Inventory

EU ID	Description	Make/ Model	Rating/ Capacity	Fuel/ tank content	NRE Status
Oil and Gas Processing Facility					
1a	2100 LP Compressor Engine w/CATOX controls	CAT 3406 TA	276 hp	Natural/Fuel Gas	No
1b	2100 LP Compressor Engine w/CATOX controls	CAT 3406 TA	276 hp	Natural/Fuel Gas	No
1c	2100 LP Compressor Engine	TBD	276 hp	Natural/Fuel Gas	No
2	PF-2 Gas Compressor Engine w/CATOX controls	CAT 3608 LE Engine	2,370 hp	Natural/Fuel Gas	No
2a	Gas Compressor Engine w/CATOX controls	CAT G3612	3,750 hp	Natural/Fuel Gas	No
2b	Gas Compressor Engine w/CATOX controls	CAT G3612	3,750 hp	Natural/Fuel Gas	No
2c	Gas Compressor Engine w/CATOX controls	CAT G3612	3,750 hp	Natural/Fuel Gas	No
3	PF-3 Gas Compressor Engine Backup w/ CATOX controls	CAT 3608 LE Engine	2,370 hp	Natural/Fuel Gas	No
4	PF-4 Crude Oil Heater A	BS&B Profire 2100E	4.5 MMBtu/hr	Natural/Fuel Gas	No
5	PF-5 Crude Oil Heater B	TBD	4.5 MMBtu/hr	Natural/Fuel Gas	No
6	PF-6 Crude Oil Heater Backup	BS&B ProFire 2100E	0.5 MMBtu/hr	Natural/Fuel Gas	No
7a	PF-7 Microturbine	Capstone C1000	11.4 MMBtu/hr	Natural/Fuel Gas	No
8a	PF-8 Microturbine	Capstone C1000	11.4 MMBtu/hr	Natural/Fuel Gas	No
9a	PF-9 Microturbine	Capstone C1000	11.4 MMBtu/hr	Natural/Fuel Gas	No
10	PF-10 Diesel Generator Engine Backup	CAT XQ375	375 kW	Diesel	No
11	PF-11 Vapor Combustor	ABUTEC 6 MW thermal oxidizer	20.5 MMBtu/hr	Natural/Fuel Gas	No
12	TEG Dehydrator	BS&B F151029	35 MMscf/day	NA	No

EU ID	Description	Make/ Model	Rating/ Capacity	Fuel/ tank content	NRE Status
12a	TEG Dehydrator	TBD	0.65 MMBtu/hr (reboiler) 35 MMscf/day	Natural/Fuel Gas	No
13	PF-12a Low Pressure Flare	GBA 3/8 VSF (PF 4)	27.3 MMBtu/hr	Natural/Fuel Gas	No
	PF-12b High Pressure Flare	GBA 3/8 VSF (PF 4)	60 MMscf/day	Natural/Fuel Gas	No
48	Truck Loading Racks	TBD	15,000 bbl/day	NA	No
51	PF-6 Offspec Oil Tank Heater	BS&B ProFire 2100E	0.5 MMBtu/hr	Natural/Fuel Gas	No
82	Truck Loading Boiler	Burnham 810HE	0.505 MMBtu/hr	Natural/Fuel Gas	No
83	HP Separator Line Heater A	TBD	5.5 MMBtu/hr	Natural/Fuel Gas	No
84	Test Separator Line Heater B	TBD	3.0 MMBtu/hr	Natural/Fuel Gas	No
85	MRU Indirect Heater 1	Flameco SB30/18-16	1.6 MMBtu/hr	Natural/Fuel Gas	No
86	MRU Indirect Heater 2	Flameco SB30/18-16	1.6 MMBtu/hr	Natural/Fuel Gas	No
87	Desiccant Dehydrator 1 (vent)	TBD	NA	NA	No
88	Desiccant Dehydrator 2 (vent)	TBD	NA	NA	No
89	Glycol Boiler 1	TBD	2.2 MMBtu/hr	Diesel	No
90	Glycol Boiler 2	TBD	2.2 MMBtu/hr	Diesel	No
91	Glycol Boiler 3	TBD	2.2 MMBtu/hr	Diesel	No
Onshore Storage Tanks					
T1-T10	Crude Oil/Off-Spec Crude Oil Storage Tanks	unknown	31,500 gallons, each	Crude Oil	No
T11	Produced Water (ABJ-4000)	unknown	31,500 gallons	Produced Water	No
T12 – T13	Vac Tank (TV500)	unknown	550 gallons	Oily water/slops	No
T14 - T17	Mineral Oil Drilling Tanks	unknown	16,800 gallons, each	Mineral Oil	No
T18	Diesel Tank (BCT-02)	unknown	1,242 gallons	Diesel	No
T19	Diesel Tank (BCT-03)	unknown	528 gallons	Diesel	No

EU ID	Description	Make/ Model	Rating/ Capacity	Fuel/ tank content	NRE Status
T20	Diesel Tank (BCT-04)	unknown	1,242 gallons	Diesel	No
T21	Diesel Tank (BCT-05)	unknown	787 gallons	Diesel	No
T22	Diesel Tank (BCT-06)	unknown	823 gallons	Diesel	No
T23	Diesel Tank (BCT-07)	unknown	500 gallons	Diesel	No
T24	Diesel Tank (Drill Rig)	unknown	528 gallons	Diesel	No
T25	Diesel Tank (Rig Tank 1)	unknown	18,480 gallons	Diesel	No
T26	Diesel Tank (Rig Tank 2))	unknown	18,480 gallons	Diesel	No
T27	Chemical Injection Tank (ABJ-4100A)	unknown	550 gallons	Scale inhibitor	No
T28	Chemical Injection Tank (ABJ-4100B)	unknown	550 gallons	Corrosion inhibitor	No
T29	Chemical Injection Tank (ABJ-4100C)	unknown	550 gallons	Emulsion breaker	No
T30	Chemical Injection Tank (ABJ-4100D)	unknown	550 gallons	Defoamer	No
Drill Rig Units					
15	ODR-1 Hot Air Heater 1	Dragon Fire	3 MMBtu/hr	No. 2 Fuel Oil Natural/Fuel Gas	No
16	ODR-2 Hot Air Heater 2	Dragon Fire	3 MMBtu/hr	No. 2 Fuel Oil Natural/Fuel Gas	No
17	ODR-3 Rig Engine 1	TBD	1,476 hp	Dual Fuel	Yes
18	ODR-4 Rig Engine 2	TBD	1,476 hp	Dual Fuel	Yes
19	ODR-5 Rig Engine 3	TBD	1,476 hp	Dual Fuel	Yes
20	ODR-6 Rig Engine 4	TBD	1,476 hp	Dual Fuel	Yes
21	ODR-7 Rig Engine 5	TBD	1,476 hp	Dual Fuel	Yes
22	ODR-8 Kohler Cold Start Engine	Yanmar	10 hp	Diesel	Yes
49	ODR-9 Boiler 1	Hurst Power Flame	8.4 MMBtu/hr	No. 2 Fuel Oil Natural/Fuel Gas	No
50	ODR-10 Boiler 2	Hurst Power Flame	8.4 MMBtu/hr	No. 2 Fuel Oil Natural/Fuel Gas	No
Onshore Auxiliary Equipment					
69	Portable Auxiliary Generator	CAT C18	831 hp	ULSD	Yes
70	Various NREs	TBD	3,896 hp, total	ULSD	Yes
71a	Various Portable Heaters	TBD	16 MMBtu/hr, cumulative	ULSD	No

Table III.K.13.F-A25 Cosmopolitan Project Jack-Up Rig (Offshore) Emission Inventory

EU ID	Description	Make/ Model	Rating/Capacity	Fuel	NRE Status
Jack-Up Rig					
23	JU-1 Rig Engine 1	TBD	1100 hp	Diesel	Yes
24	JU-2 Rig Engine 2	TBD	1100 hp	Diesel	Yes
25	JU-3 Rig Engine 3	TBD	970 hp	Diesel	Yes
26	JU-4 Rig Engine 4	TBD	970 hp	Diesel	Yes
27	JU-5 Rig Engine 5	TBD	970 hp	Diesel	Yes
28	JU-6 Rig Engine 6	TBD	970 hp	Diesel	Yes
29	JU-7 Rig Engine 7	TBD	970 hp	Diesel	Yes
30	JU-8 Crane Engine 1	TBD	300 hp	Diesel	Yes
31	JU-9 Crane Engine 2	TBD	285 hp	Diesel	Yes
32	JU-10 Diesel Storage Tank	TBD	32,718 gal	NA	No
33	JU-11 Diesel Storage Tank	TBD	28,896 gal	NA	No
34	JU-12 Diesel Storage Tank	TBD	17,220 gal	NA	No
35	JU-13 Diesel Storage Tank	TBD	17,220 gal	NA	No
36	JU-14Temporary Well Testing Flare	TBD	15 MMscf/well location	Fuel Gas	No
Well Service and Testing Equipment					
37	WST-1 Portable Boiler/Heater	TBD	1.0 MMBtu/hr	No. 2 Fuel Oil	No
38	WST-2 Portable Boiler/Heater	TBD	1.0 MMBtu/hr	No. 2 Fuel Oil	No
39	WST-3 Portable Boiler/Heater	TBD	1.0 MMBtu/hr	No. 2 Fuel Oil	No
40	WST-4 Portable Boiler/Heater	TBD	1.0 MMBtu/hr	No. 2 Fuel Oil	No
41	WST-5 Well Testing Engine	TBD	440 hp	Diesel	Yes
42	WST-6 Well Testing Engine	TBD	440 hp	Diesel	Yes
43	WST-7 Well Testing Engine	TBD	440 hp	Diesel	Yes
44	WST-8 Well Testing Engine	TBD	440 hp	Diesel	Yes
45	WST-9 Well Testing Engine	TBD	440 hp	Diesel	Yes
46	WST-10 Well Testing Engine	TBD	440 hp	Diesel	Yes
47	WST-11 Well Testing Engine	TBD	440 hp	Diesel	Yes

The stationary source began operation in 2015 with the issuance of Minor Permit AQ1385MSS01 and therefore did not have emissions to report in the 2014 NEI. In the 2017 NEI the stationary source reported 14.8 tons of SO_2. This was an overly conservative estimate based on fuel gas burning EUs operating at their permitted limit of 320 ppmv total sulfur in the fuel, when in actuality the concentrations were an order of magnitude lower.

ADEC reviewed the H_2S concentrations in the fuel gas reported for the stationary source over a four-year period from 2016 through 2019 and recalculated actual SO_2 emissions. During this timeframe the stationary source has had extremely low H_2S values reported, usually under 6 ppmv. Beginning in 2019, the source installed a new mechanical refrigeration unit to better meet pipeline quality gas standards which lowered H_2S concentrations in the gas even further. Therefore, ADEC conservatively assumed 16 ppmv sulfur in the fuel gas for recalculating SO_2 emissions for 2016-2019 which resulted in values of 0.59 tpy, 1.73 tpy, 1.02 tpy, and 0.95 tpy respectively. The low annual SO_2 emissions at the stationary source are a result of the liquid fuel burning EUs exclusively combusting ULSD and the gaseous fuel EUs exclusively combusting low sulfur natural gas.

The conclusion of ADEC's review for Bluecrest's Cosmopolitan Project is that the stationary source is already using effective SO_2 controls by combusting low sulfur natural gas and ULSD in all of their fuel burning EUs and has low annual SO_2 emissions averaging around one tpy. Therefore, the stationary sources actual SO_2 emissions cannot sizably be lowered any further. ADEC will continue to monitor the SO_2 emissions from the Cosmopolitan Project to ensure that there are no substantial increases going forward that would have a negative impact on RH visibility.

3 Limited Review – Non Permitted Facilities

The facilities included in this area are those facilities that are operating under an Owner Requested Limit (ORL) under 18 AAC 50.225. ADEC issues ORLs as permit avoidance tools. The owner or operator of an existing or proposed stationary source may request an enforceable limit on the ability to emit air pollutants to avoid all permitting obligations under AS 46.14.130. An ORL can contain any number of enforceable limits for an emissions unit that ensures the stationary source's potential to emit remains below permitting thresholds.

a. Ted Stevens International Airport

In addition to the emissions from aviation traffic at the Ted Stevens International airport, the Alaska Department of Transportation has an ORL permit avoidance tool to maintain airport operations, AQ0089ORL09. The EUs covered under the ORL include gas-fired boilers, diesel-fired generators, gas-fired chillers, gas-fired duct burners, and gas-fired radiant heat tubes. The combined potential to emit for these EUs is 5.22 tons per year of SO_2. The low potential to emit for these EUs is a result of a 700 hour per 12 consecutive month period combined limit on the diesel generators and the fact that all other EUs are combusting low sulfur natural gas. Therefore, ADEC did not evaluate this facility for any potential emissions reductions as no meaningful reductions could be achieved.

b. Port of Alaska (Anchorage)

In addition to the emissions from marine vessel traffic at the Port of Alaska (Anchorage), there are three fuel storage tank terminal stationary sources located at the port. These facilities are the Municipality of Anchorage's Port of Alaska (Anchorage) Fuel Loading and Unloading, Petro Star, Inc.'s Port of Alaska Terminal, and Tesoro Logistics Operations, LLC's Ocean Dock Terminal and Anchorage Terminal II. ADEC did not evaluate these facilities because their combined potential to emit for SO_2 is 1.82 tpy, and no meaningful reductions could be achieved.

4 Limited Review – Non Permitted Facilities

The nonpoint or nonroad (NP/NR) sources identified in this section were analyzed under a sector analysis using available data submitted to the EPA for triennial NEI purposes. The source sectors analyzed for their RH impacts were broadly the state marine, aviation, and rail sectors. The summaries listed below are limited to those identified potential sources of visibility impairment at Class I areas; remaining statewide data can be found in Appendix III.K.13.F. Due to the regulatory framework in place at present, ADEC has few regulations applicable to these two categories of sources.

Three categories of NP/NR sectors are used in the below analysis: aviation, marine, and railroad. All have activity data which is provided to ADEC by the EPA in its triennial NEI reporting which has been used in WEP/AOI to better understand and comprehend the contributions of these sectors to visibility at state Class I areas.

A summary of NEI source sector categories is provided below:

a. Marine Sector

Within the marine sector data provided to ADEC by EPA, vessels are divided into three categories differentiated by engine size and horsepower capacity. Category 1 (C1) and Category 2 (C2) marine vessels utilize small engines and are mainly outboard skiff-types, jet-skis or other enthusiast type engines, or smaller coastal fishing boats that operate in state waters, the Gulf of Alaska, or the Bering Sea. Alaska has many of these types of vessels operating on a yearly basis. Depending on the size and horsepower capacity this umbrella can also encompass some smaller harbor tugs or pilot vessels operating in regional or local harbors on or off the road system.

Category 3 (C3) marine vessels are larger coastal, ocean-going, or inter-continental ships which can fall under any number of sub-categories. These can include larger harbor or ocean-going tugs, oil tankers, break-bulk cargo vessels, ore carriers, container ships, cruise vessels, or the fleet of Alaska state ferries. These vessels are also prevalent in state waters and carry much of the heavy cargo and container traffic from the hub communities to more remote towns and settlements across the state and Alaska Panhandle.

At present, there are a limited set of emissions controls which apply to this category of traffic. The EPA has mandated the use of ULSD for a variety of engines and equipment since the calendar year 2000 time frame. This regulation applies to both stationary and mobile sources. Marine sources are also required to utilize lower-sulfur marine fuels in state waters and are mandated to 0.01% sulfur content diesel within the designated boundaries of the North American Emissions Control Area (ECA). This area includes all of Southeast Alaska and much of the Gulf of Alaska to the northern end of Kodiak Island.

In addition, the IMO has mandated the use of 0.5% low-sulfur marine fuel for all Annex VI signatory countries starting January 1, 2020. This treaty stipulation ensures that most international marine traffic transiting Alaska waters from international sources and not operating within the ECA must use lower sulfur content fuel compared to bunker fuel burned before January 2020. ADEC considers this a form of emissions control and will be examining its effectiveness in the 2024 progress report to examine whether additional sulfur controls are required to meet ongoing RPGs for coastal and inland Class I areas.

Three identified sources are covered in the below sector analysis: the Port of Alaska (Anchorage), Port McKenzie, and the Port of Homer. The Port of Alaska (Anchorage) has significant amounts of C3 marine traffic due to its hub status for Southcentral and Interior Alaska. Because of its close location to the Port of Alaska (Anchorage), Port McKenzie is included as a sub-heading under the larger Port of Alaska (Anchorage). The Port of Homer is a smaller regional port located at the southern end of the road system on the Kenai Peninsula. It handles small amounts of C3 marine traffic and acts as a USCG safety inspection point and anchorage location for vessels transiting north through Cook Inlet to the Nikiski Oil Refinery and the Port of Alaska (Anchorage). All three ports handle traffic from the three categories of marine vessels.

b. Aviation Sector

Data analyzed in the aviation sector analysis is made up of two categories of emissions: Takeoff and Landing (LTO) data and cruise emissions. Triennial NEI data is divided between civilian and military aviation categories and is further sub-divided into turbofan (jet), turboprop, and piston-powered aircraft. The division of aircraft emissions into LTO and cruise altitude allows for a more detailed analysis and estimation of total aircraft emissions due to differences in engine activity and output during the two phases of operation. As such, data listed below for Trapper Creek, Homer, and Anchorage Ted Stevens International airports lists these as separate categories of data.

c. Railroad Sector

Alaska has two operational railroads active as of 2018: The Alaska Railroad (AKRR) and the White Pass and Yukon Railroad (WPYRR). Of these, only the AKRR operates adjacent to a designated Class I area and could potentially generate emissions which would appear on the

IMPROVE monitors nearby. Data for the WPYRR is not included in either the below analysis or the longer sector analysis appendix, as amounts and distances between emissions point and nearest Class I area do not necessitate technical analysis at this time. Railroad data is derived from borough and census area fuel consumption figures submitted to ADEC and emissions data made available in the NEI.

d. Port of Alaska (Anchorage) (Marine Non-Point Emissions)

The Port of Alaska (Anchorage), formerly known as the Port of Anchorage, is the largest operating port facility in the state and serves most communities in Southcentral and Interior Alaska. As a result, it receives a significant amount of large oceangoing cargo vessels and tankers on a yearly basis. This marine activity can generate measurable amounts of emissions which have been shown to influence visibility monitors at two of the state Class I areas (Tuxedni and Denali). Marine traffic operating within Cook Inlet is mandated to burn low-sulfur marine fuels as per EPA and USCG regulations for the ECA. The Port of Alaska (Anchorage) has traffic from all three categories of marine traffic; emissions data for all are included below.

e. Category 1 and 2 Marine Traffic

Anchorage's C1 and C2 marine emissions footprint is small, with only 120 tons of NO_x reported in the Triennial NEI, and a half-ton of SO_2 for the same year. As the Port of Alaska (Anchorage) is designed for larger cargo vessels and not smaller classes, this emissions footprint for these two classes of vessel is consistent with traffic patterns at the port. Based on the below emissions data (Table III.K.13.F-A26), ADEC does not suggest additional regulatory controls for emissions at this time.

Table III.K.13.F-A26 Category 1 and Category 2 Marine Emissions in Anchorage Municipality and Borough

Borough	CO Emissions (tons)	NO_x Emissions (tons)	SO_2 Emissions (tons)	PM_{10} Emissions (tons)	$PM_{2.5}$ Emissions (tons)	VOC Emissions (tons)
Anchorage Municipality and Borough (Anch. Muni)	18.158	120.062	0.558	3.216	3.116	3.990

f. Category 3 Marine Traffic

Anchorage C3 traffic represents a significant amount of marine traffic providing material transport services to Southcentral and Interior Alaska. NO_x and SO_2 emissions are greater for C3 vessels than those in C1 and C2. NO_x emissions are roughly double what was generated by C1 and C2 vessels during the inventory year, while SO_2 emissions were 14 times greater. However, even with the larger SO_2 emissions footprint generated by annual large vessel traffic at the Port of Anchorage, annual totals are still under ten tons per year. As all vessels operating in Cook Inlet are subject to ECA low-sulfur fuel regulations, along with the distances to the nearest Class

I areas being over one hundred miles, ADEC does not suggest additional regulatory controls for marine emissions currently.

ADEC can revisit Anchorage C3 emissions at the progress report and suggest additional controls should the emissions profile of the Port of Alaska (Anchorage) change and require review at that time. (Table III.K.13.F-A27)

Table III.K.13.F-A27 Category 3 Marine Emissions in Anchorage Municipality

Borough	CO Emissions (tons)	NO_x Emissions (tons)	SO_2 Emissions (tons)	PM_{10} Emissions (tons)	$PM_{2.5}$ Emissions (tons)	VOC Emissions (tons)
Anchorage Municipality and Borough	30.197	235.268	8.299	4.464	4.107	20.526

g. Port McKenzie (Marine Non-Point Emissions)

Port McKenzie is a small local port at the northern end of Cook Inlet with limited road access. It lies within the AOI of the Port of Alaska (Anchorage). It has been identified as a potential terminal for the proposed Alaska Natural Gas Pipeline alongside the Port of Nikiski. Most marine traffic active at Port McKinzie is either C1 or C2 marine vessels and does not represent a significant source of visibility impairment. As such, it is likely that Port McKenzie was identified as a potential source of impairment due to its location within the Anchorage AOI and the greater Municipality of Anchorage. Emissions data for the limited marine traffic is grouped into the larger Anchorage dataset.

It is the stance of ADEC that any discussion of controls for current marine traffic at Port McKenzie is unnecessary due to low traffic volume and lack of port development. ADEC can revisit the subject of regulatory controls should the emissions profile of Port McKenzie change, or new port developments render the above analysis out-of-date.

h. Ted Stevens Anchorage International Airport (Aviation Non-Point Emissions)

Currently, Anchorage has the largest international airport in the state (Ted Stevens-Anchorage International Airport), which serves as a passenger and air cargo logistical hub for both the state and the Pacific Rim. Passenger flights depart Anchorage year-round for hub communities throughout the state, including Dillingham, Nome, Kotzebue, and Utqiagvik. During the spring and summer months, the airport also hosts international passenger flights to destinations in Korea, China, Japan, and Germany.

The airport's cargo operations host large international cargo flights year-round to destinations throughout North America, Asia, and Europe. Ted Stevens-Anchorage International has also begun hosting increasing numbers of Amazon cargo flights in the last few years. For future projections, it will be important to analyze both the EPA's provided 2028 projections as well as examining publicly available information on the cargo hub's utilization by air carriers for potential visibility impacts on Denali and Tuxedni Class I areas.

For civil aviation, total emissions of both SO_2 and NO_x increased markedly between 2014 and 2016. Commercial aircraft emissions, a category encompassing both passenger and cargo aircraft, increased significantly over that three-year time frame. An additional 110 tons of SO_2 were emitted between 2014 and 2016, while NO_x emissions rose by 400 tons. This indicates an increasing reliance on the Anchorage airport by both domestic and international air carriers for passengers and cargo transport. Military emissions remained stable over the period, to within a few tons of SO_2 and NO_x from 2014 to 2016.

Future projections for emissions growth potential need to take both the economic potential of the rest of the state into consideration, as well as potential tourist growth. Ted Stevens-Anchorage International Airport is the primary arrivals and departures point for passengers cruising the Inside Passage. As is discussed in the marine sector analysis, cruise vessel traffic is set to increase over the next decade, with larger vessels with greater capacity carrying thousands more passengers to and from the state. This will likely be mirrored in increasing numbers of commercial aircraft utilizing the Anchorage airport, as these passengers will need to get to and from their port calls. Most Alaska cruises arrive and depart from Anchorage, Whittier, or Seward. This necessitates the use of Ted Stevens-Anchorage International Airport to get passengers to and from their vessels. (Table III.K.13.F-A28)

Table III.K.13.F-A28 Anchorage Municipal Aircraft Emissions

Borough/CA	**Equipment Type**	**SO_2 - 2014 Emissions (tons)**	**NO_x- 2014 Emissions (tons)**	**SO_2 – 2016 Emissions (tons)**	**NO_x- 2016 Emissions (tons)**
Anch. Muni	Comm. Air.	159.22	1605.25	271.26	2013.03
Anch. Muni	Gen. Av.: Piston	0.64	4.13	1.18	4.45
Anch. Muni	Gen. Av.: Turbine	1.81	7.96	4.53	14.96
Anch. Muni	Air Taxi: Piston	0.20	0.94	0.08	0.81
Anch. Muni	Air Taxi: Turbine	7.74	30.41	9.49	45.69
Anch. Muni	Military	42.49	450.96	43.24	452.31
Anch. Muni	**TOTAL:**	**212.10**	**2099.62**	**329.78**	**2531.25**

Because ADEC does not have regulatory authority at this time allowing the state to control sulfur levels in aircraft fuel, and the above aircraft operations are not permitted by the agency, there exists no state control mechanism at this time to limit emissions.

i. Trapper Creek Aviation (Aviation Non-Point Emissions)

Trapper Creek has a single small airport operating near the community of Talkeetna in the Matanuska-Susitna Borough. It provides air taxi and single-engine aircraft services for tourists using aircraft to access Denali National Park and more remote communities away from the Alaska Highway and Alaska Railroad.

Emissions were recorded for Denali Borough, where Talkeetna and Denali National Park are located, below one ton of SO_2 and ten tons of NO_x, and air activity was limited to air taxis and piston-powered aircraft. Given the relative stability of emissions, and the absence of larger aircraft accessing or operating out of this area, it is unlikely that visibility will decline due to this activity.

ADEC does not recommend any forms of controls on aircraft operating out of Talkeetna or nearer to Denali National Park currently.

j. Homer Aviation and Marine (Aviation, Marine Non-Point Emissions)

Due to the compact geographical size of the community of Homer and short distance between the Homer Airport and the Port of Homer, it is difficult to differentiate which source could have generated this reading. As such, both air and marine emissions are covered below

k. Homer Aviation (Aviation Non-Point)

The Homer Airport is one of two regional airports operating in the Kenai Peninsula Borough, the other of which is the Kenai Municipal Airport further north in the community of Kenai. The Homer Airport operates primarily as a regional hub providing passenger and cargo air access for the southern Kenai Peninsula and communities in the Lake and Peninsula Borough on the western side of Cook Inlet. Because of the organization of data collection for the triennial NEI, data is only available for the full borough rather than the individual airport. A rough estimation can be generated by taking 40% of the below emissions data table (Table III.KL.13.F-A29); as the Kenai Municipal Airport receives more daily traffic due to its location and its use to bring oil field workers out from Anchorage.

Table III.K.13.F-A29 Aircraft Emissions in Kenai Peninsula Borough

Borough/CA	Equipment Type	SO_2 - 2014 Emissions (tons)	NO_x - 2014 Emissions (tons)	SO_2 - 2016 Emissions (tons)	NO_x - 2016 Emissions (tons)
Kenai Peninsula	Comm. Air.	10.45	108.95	10.48	109.04
Kenai Peninsula	Gen. Av.: Piston	0.13	0.85	0.15	0.85
Kenai Peninsula	Gen. Av.: Turbine	0.30	1.31	1.69	5.99
Kenai Peninsula	Air Taxi: Piston	0.54	0.89	0.03	0.36
Kenai Peninsula	Air Taxi: Turbine	2.85	12.09	4.00	18.05

Kenai Peninsula	TOTAL:	14.27	124.09	16.35	134.29

Using a 40 percent estimate for the above table showing SO_2 and NO_x data from two NEI datasets, total SO_2 generated by all aviation categories at the Homer Airport was 5.708 tons in 2014 and 6.54 tons in 2016. NO_x emissions were 49.63 tons in 2014 and 53.71 tons in 2016. Neither is a significant source of visibility-impairing pollutants and is unlikely to produce noticeable amounts of haze at the nearest Class I area, Tuxedni.

ADEC does not recommend any regulatory controls be placed on the airport at this time. However, this finding could be reviewed in 2024 during the progress report at which time a new glideslope and impairment dataset will be available for the KPB01 monitor. It is possible that with shorter distances between the airport and the new monitoring site north of the community, the airport could become a greater source of visibility impairing pollution.

l. Homer Marine (Maritime Non-Point)

The community of Homer has a small boat harbor at the far end of the Homer Spit providing moorage and shelter for a variety of fishing boats and other C1 and C2 vessels. The only site which has the capacity of hosting larger vessel traffic is Kachemak Bay, which is used as an anchorage location for C3 vessels transiting north to Nikiski or Anchorage. Large internationally flagged cargo vessels and oil tankers use the anchorage as a convenient location to conduct USCG vessel inspections upon entering U.S. territorial waters. Because these are a small statistical percentage of the overall marine traffic in the Kenai Peninsula Borough as calculated by the triennial NEI, the below C1, C2, and C3 data likely far outweighs yearly activity at the Port of Homer. (Table III.K.13.F-A30 and Table III.K.13.F-A31)

Table III.K.13.F-A30 C1 and 2 Marine Traffic in Kenai Peninsula Borough

Borough	CO Emissions (tons)	NO_x Emissions (tons)	SO_x Emissions (tons)	PM_{10} Emissions (tons)	$PM_{2.5}$ Emissions (tons)	VOC Emissions (tons)
Kenai Peninsula	92.684	612.517	1.784	16.206	15.710	21.864

Table III.K.13.F-A31 C3 Marine Traffic in Kenai Peninsula Borough

Borough	CO Emissions (tons)	NO_x Emissions (tons)	SO_x Emissions (tons)	PM_{10} Emissions (tons)	$PM_{2.5}$ Emissions (tons)	VOC Emissions (tons)
Kenai Peninsula	26.233	248.400	9.951	4.503	4.142	12.323

The above table shows likely C3 traffic at the Nikiski Oil Refinery and marine terminal along with traffic from the Port of Homer; therefore it is extremely unlikely that the 248 tons of NO_x and nearly 10 tons of SO_2 can all be attributed to the Port of Homer.

As with the Homer Airport, ADEC does not recommend any additional controls or regulatory requirements be instituted for marine traffic at the Port of Homer at this time. This recommendation can be revisited in 2024 when the progress report will be published and a new glideslope and visibility data available for the KPB01 monitoring station.

m. Ninilchik (Non-Point/Non-Road)

Due to the presence of the Port of Nikiski together with oil and natural gas platforms located in the vicinity of this WEP reading, it is unclear which source this reading can be attributed to at this time. Should a future WEP reading during the 2024 RH progress report or 2028 third RH Plan generate a clearer identification of this non-point reading, this location can be revisited at that time.

n. Alaska Railroad (Railroad Non-Point Emissions)

The below data represents available fuel consumption data and emissions from the AKRR for the 2016 NEI, submitted to the EPA. Data for the WPYRR is not included due to distances and relative activity and fleet size. Fuel and emissions are broken out by borough. (Table III.K.13.F-A32)

Table III.K.13.F-A32 Alaska Railroad Fuel Consumption and Emissions by Borough

Borough	ULSD Consumed (in gallons)	NO_x EF	NO_x E	PM_{10} EF	PM_{10} E	HC EF	HC E	VOC EF	VOC E	$PM_{2.5}$ EF	$PM_{2.5}$ E	SO_2 EF	SO_2 E
Anch. Muni	800,620	131	115.61	0.11	0.10	6.30	5.56	6.63	5.85	3.49	3.08	0.09	0.08
Denali	450,821	131	65.10	0.11	0.05	6.30	3.13	6.63	3.30	3.49	1.74	0.09	0.05
Mat-Su	869,141	131	125.51	0.11	0.10	6.30	6.04	6.63	6.36	3.49	3.35	0.09	0.09
Fairbanks	302,480	131	43.68	0.11	0.04	6.30	2.10	6.63	2.21	3.49	1.16	0.09	0.03
Yukon-Kuskokwim	299,399	131	43.23	0.11		6.30	2.08	6.63	2.19	3.49		0.09	
Seward (Kenai Peninsula)	140,097	131	20.23	0.11	0.02	6.30	0.97	6.63	1.02	3.49	0.54	0.09	0.01
Whittier (Valdez-Cordova)	93,600	131	13.52	0.11	0.01	6.30	0.65	6.63	0.68	3.49	0.36	0.09	0.01
Total Fuel (2016)	2,956,158		426.87		0.35		20.53		21.62		11.38		0.31

For the purposes of RH planning and visibility modeling, there is little in the way of emissions or fuel controls that could be put in place which would improve visibility at Alaska's Class I areas. AKRR operations between the Kenai Peninsula and Denali National Park constitute most of the railroad's yearly passenger transportation activities. Some rail activities between Denali and Fairbanks occur, though much of the railroad's traffic during the tourist season is among the cruise ports of Seward, Whittier, Anchorage, and Denali National Park.

Only the AKRR has emissions-generating activity located within or near any of Alaska's Class I areas. Most of the AKRR's passenger activity is tourism and sightseeing related around the cruise industry, and many cruise passengers travel up the Inside Passage with the intention of taking the railroad north to Denali National Park to observe wildlife and stay near the mountain. Based on data submitted to the EPA for the 2017 NEI, the railroad burned 450,000 gallons of ULSD in Denali Borough in 2017. This amount of fuel burned is half of the 870,000 gallons burned by the railway in the Matanuska-Susitna Borough.

As the railway is already burning ULSD in its engines, and half of its locomotive fleet is of a newer build date than the year 2001, there is no reason to suggest any additional control mechanism based on annual emissions amounts.

Based on the above analysis, ADEC does not recommend controls be installed or regulatory requirements put in place for the purposes of visibility improvement based on AKRR activity near Class I areas.

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street ● Homer, Alaska 99603 ● (907) 235-8551

March 27, 2015

Certified Mail: 7011 1570 0001 6394 1178

ADEC Air Permit Program
Attn: Nattinee Nipataruedi
410 Willoughby Ave., Suite 303
PO Box 111800
Juneau, AK 99811-1800

Re: Bernice Lake Power Plant – 2014 Triennial Point Source Emission Inventory
Air Quality Operating Permit No. AQ0086TVP02, Revision 2

Dear Mrs. Nipataruedi:

Enclosed is the 2014 Triennial Emission Inventory Report for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant. If you have any questions or concerns about this report, please feel free to contact me at 335-6176 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

Certification of Responsible Official

"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."

Responsible Official: ______________________________
Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Emission Inventory - 2014

(Mandatory information highlighted)

FACILITY INFORMATION

ADEC PERMIT ID	86
Stationary Source (Facility) Name:	Bernice Lake Power Plant
AFS ID:	212200034
Census Area/Community:	122 - Kenai Peninsula Borough
Line of Business (NAICS):	221112 - Electrical Power Generation
Contact Name:	Bruce Linton
Contact Phone:	(907) 335-6176
Physical Address:	55244 Chevron Refinery Road
Mailing Address:	280 Airport Way, Kenai AK 99611

EMISSION UNIT

ID:	1
Description:	Gas Turbine - Unit #2
Manufacturer:	General Electric
Model Number:	Frame 5
Serial Number:	
Manufactured Year:	1971
Design Capacity:	263 MM BTU/hr

CONTROL EQUIPMENT
(if applicable)

ID:	Not Applicable
Type:	
Manufacturer:	
Model:	
Control Efficiency(%):	
Capture Efficiency(%):	
Total Capture Efficiency(%):	
Pollutants Controlled:	

PROCESS

SCC Code:	20100201
Material Processed:	Natural Gas
Operational Periods:	
Start Date:	1/1/2014
End Date:	12/31/2014

FUEL INFORMATION

Ash Content (weight %):	
Elem. Sulfur Content (weight %):	
H2S Sulfur Content (ppmv):	
Heat Content:	1,020 BTU/scf
Heat Input (MMBtu/hr):	
Heat Output (MMBtu/hr):	

THROUGHPUT

Total Amount:	23.7 MMscf during 2014
Summer:	25%
Fall:	25%
Winter:	25%
Spring:	25%
Days/Week:	7
Weeks/Periods:	52
Hours/Day:	24
Hours/Period:	8760

STACK DETAIL

ID:	1
Type:	Vertical
Measurement Units:	English
Base Elevation:	
Stack Height:	25
Stack Diameter:	
Exit Gas Temp:	
Exit Gas Velocity:	
Actual Exit Gas Flow Rate:	
Data Source:	
Description:	GE Frame 5 Gas Turbine
Latitude:	60.69385
Longitude:	-151.38713
Location Description:	
Accuracy (m):	10
Datum:	NAD-1983

Comments: The latitude and longitude given are for the center of the facility.

EMISSIONS					
Pollutant	**Emission Factor (Total)**	**Emission Factor (Numerator)**	**Emission Factor (Denominator)**	**Emission Factor (Source)**	**Tons Emitted**
CO	0.082	lb	MMBtu	AP-42 Table 3.1-1	2.3
NH_3	N/A			-	-
NO_X	0.32	lb	MMBtu	AP-42 Table 3.1-1	9
PM_{10}-PRI	0.0066	lb	MMBtu	AP-42 Table 3.1-2a	0.2
$PM_{2.5}$-PRI	N/A			-	-
SO_2	0.0002	lb	MMBtu	Mass Balance	9.50000
VOC	0.0021	lb	MMBtu	AP-42 Table 3.1-2a	0.1

Comments: AP-42 does not list emission factors for NH_3 and $PM_{2.5}$-PRI in Section 3.1 for stationary gas turbines. Therefore, quantities were not calculated for these pollutants.

EMISSION UNIT

ID:	2
Description:	Gas Turbine - Unit #3
Manufacturer:	General Electric
Model Number:	Frame 5
Serial Number:	
Manufactured Year:	1978
Design Capacity:	324.5 MM BTU/hr

CONTROL EQUIPMENT
(if applicable)

ID:	Unit 3 - Water Injection
Type:	Water Injection
Manufacturer:	BPI
Model:	
Control Efficiency(%):	
Capture Efficiency(%):	
Total Capture Efficiency(%):	
Pollutants Controlled:	NOx

PROCESS

SCC Code:	20100201
Material Processed:	Natural Gas
Operational Periods:	
Start Date:	1/1/2014
End Date:	12/31/2014

FUEL INFORMATION

Ash Content (weight %):	
Elem. Sulfur Content (weight %):	
H2S Sulfur Content (ppmv):	
Heat Content:	1,020 BTU/scf
Heat Input (MMBtu/hr):	
Heat Output (MMBtu/hr):	

THROUGHPUT

Total Amount:	142.8 MMscf during 2014
Summer:	25%
Fall:	25%
Winter:	25%
Spring:	25%
Days/Week:	7
Weeks/Periods:	52
Hours/Day:	24
Hours/Period:	8760

STACK DETAIL

ID:	2
Type:	Vertical
Measurement Units:	English
Base Elevation:	
Stack Height:	25
Stack Diameter:	
Exit Gas Temp:	
Exit Gas Velocity:	
Actual Exit Gas Flow Rate:	
Data Source:	
Description:	GE Frame 5 Gas Turbine
Latitude:	60.69385
Longitude:	-151.38713
Location Description:	
Accuracy (m):	10
Datum:	NAD-1983

Comments: The latitude and longitude given are for the center of the facility.

EMISSIONS					
Pollutant	**Emission Factor (Total)**	**Emission Factor (Numerator)**	**Emission Factor (Denominator)**	**Emission Factor (Source)**	**Tons Emitted**
CO	0.285	lb	MMBtu	Source Test Factor	34.8
NH_3	N/A			-	-
NO_X	78.3	lb	hr	Source Test Factor	29.8
PM_{10}-PRI	0.0066	lb	MMBtu	AP-42 Table 3.1-2a	4.5
$PM_{2.5}$-PRI	N/A			-	-
SO_2	0.0002	lb	MMBtu	Mass Balance	41.000
VOC	0.0021	lb	MMBtu	AP-42 Table 3.1-2a	0.3

Comments: AP-42 does not list emission factors for NH_3 and $PM_{2.5}$-PRI in Section 3.1 for stationary gas turbines. Therefore, quantities were not calculated for these pollutants.

EMISSION UNIT

ID:	3
Description:	Gas Turbine - Unit #4
Manufacturer:	General Electric
Model Number:	Frame 5
Serial Number:	
Manufactured Year:	1981
Design Capacity:	324.5 MM BTU/hr

CONTROL EQUIPMENT
(if applicable)

ID:	Unit 4 - Water Injection
Type:	Water Injection
Manufacturer:	BPI
Model:	
Control Efficiency(%):	
Capture Efficiency(%):	
Total Capture Efficiency(%):	
Pollutants Controlled:	NOx

PROCESS

SCC Code:	20100201
Material Processed:	Natural Gas
Operational Periods:	
Start Date:	1/1/2014
End Date:	12/31/2014

FUEL INFORMATION

Ash Content (weight %):	
Elem. Sulfur Content (weight %):	
H2S Sulfur Content (ppmv):	
Heat Content:	1,020 BTU/scf
Heat Input (MMBtu/hr):	
Heat Output (MMBtu/hr):	

THROUGHPUT

Total Amount:	388.5 MMscf during 2014
Summer:	25%
Fall:	25%
Winter:	25%
Spring:	25%
Days/Week:	7
Weeks/Periods:	52
Hours/Day:	24
Hours/Period:	8760

STACK DETAIL

ID:	3
Type:	Vertical
Measurement Units:	English
Base Elevation:	
Stack Height:	25
Stack Diameter:	
Exit Gas Temp:	
Exit Gas Velocity:	
Actual Exit Gas Flow Rate:	
Data Source:	
Description:	GE Frame 5 Gas Turbine
Latitude:	60.69385
Longitude:	-151.38713
Location Description:	
Accuracy (m):	10
Datum:	NAD-1983

Comments: The latitude and longitude given are for the center of the facility.

EMISSIONS

Pollutant	Emission Factor (Total)	Emission Factor (Numerator)	Emission Factor (Denominator)	Emission Factor (Source)	Tons Emitted
CO	0.198	lb	MMBtu	Source Test Factor	33.3
NH_3	N/A			-	-
NO_X	93.7	lb	hr	Source Test Factor	37.3
PM_{10}-PRI	0.0066	lb	MMBtu	AP-42 Table 3.1-2a	6.2
$PM_{2.5}$-PRI	N/A			-	-
SO_2	0.0002	lb	MMBtu	Mass Balance	56.400
VOC	0.0021	lb	MMBtu	AP-42 Table 3.1-2a	0.4

Comments: AP-42 does not list emission factors for NH_3 and $PM_{2.5}$-PRI in Section 3.1 for stationary gas turbines. Therefore, quantities were not calculated for these pollutants.

7011 1570 0001 6394 1239

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ADEC - Air Permits Program
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795
ATTN: Assessable Emission Estimates

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PS Form 3800, August 2006 See Reverse for Instructions

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- Print your name and address on the reverse so that we can return the card to you.
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1. Article Addressed to:

ADEC - Air Permits Program
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795
ATTN: Assessable Emission Estimates

COMPLETE THIS SECTION ON DELIVERY

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PS Form 3811, July 2013 Domestic Return Receipt

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

March 17, 2015

Certified Mail: 7011 1570 0001 6394 1239

Air Permits Program
Attn: Assessable Emission Estimates
Alaska Department of Environmental Conservation
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795

Re: Bernice Lake Power Plant – Annual Emissions Estimate for Fiscal Year 2016
Air Quality Operating Permit No. AQ0086TVP02, Revision 2

Dear Sir or Madame:

Enclosed are assessable emission estimates for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant based upom actual emissions emitted during the most recent calendar year. This estimate is submitted in accordance with Conditions 21.2 and 22 of Permit No. AQ0086TVP02, Revision 2. AEEC is requesting their assessed fee be based on this estimate rather than potential emissions.

The sources of the emission factors used in the calculations are provided in the attachment and include enforceable test methods and other emission factors from EPA's publication AP-42, Volume I.

If you have any questions or concerns about this report, please feel free to contact me at 335-6223 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

AEEC Bernice Lake Power Plant
Permit No. AQ0086TVP02
FY2016 Assessable Emission Estimate

Certification of Responsible Official

"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."

Responsible Official: ______________________

Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Summary of Projected Fiscal Year (FY) 2016 Assessable Emissions

Bernice Lake Power Plant

Projected Air Contaminant Emissions (tons per year)					
Source Type	NO_x	CO	PM	VOC	SO_2
Regulated Significant, January 1 - June 30, 2014	76.3	70.4	10.9	0.7	107.0
Regulated Insignificant	0.6	0.3	0.0	0.0	0.0
Subtotals	76.9	70.7	11.0	0.7	107.0
Total Assessable Emissions	**265.5**				

- Projected assessable emissions are based on actual operation during Calendar Year 2014.
- Calculations based on source test factors, AP-42 emission factors and mass balances, as shown in attached spreadsheets.

Bernice Lake Power Plant
Permit No. AQ0086TVP02 Rev2
Assessable Emissions for FY2016, based on actual operation in 2014

ID	Emission Unit	Emission Unit Description	Rating		FY2016 use based on actual emissions in 2014		Factor Source	Emission Factor		Emissions (tpy)
NOx										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	56545	MMBtu	AP-42 Table 3.1-1	0.32	lb/MMBtu	9.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	244349	MMBtu	Source Test Factor[1]	0.244	lb/MMBtu	29.8
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	336182	MMBtu	Source Test Factor[1]	0.222	lb/MMBtu	37.3
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.1
								Total NOx Emissions:		**76.3**
SO2										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	56545	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	9.5
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	244349	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	41.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	336182	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	56.4
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
								Total SO2 Emissions:		**107.0**
PM10										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	56545	MMBtu	AP-42 Table 3.1-2a	0.0066	lb/MMBtu	0.2
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	244	MMscf	BACT limit	12	lb/hr	4.5
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	336	MMscf	BACT limit	12	lb/hr	6.2
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
								Total PM10 Emissions:		**10.9**
CO										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	56545	MMBtu	AP-42 Table 3.1-1	0.082	lb/MMBtu	2.3
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	244349	MMBtu	Source Test Factor[3]	0.2850	lb/MMBtu	34.8
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	336182	MMBtu	Source Test Factor[3]	0.1980	lb/MMBtu	33.3
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
								Total CO Emissions:		**70.4**
VOC										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	56545	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.1
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	244349	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.3
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	336182	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.4
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
								Total VOC Emissions:		**0.7**

Based on most recent 2012 source test
Based on calendar year 2011 operation, because data for calendar year 2014 was unavailable
Source test factors taken from January 2008 emissions test on Units 3 and 4. This is the most recent CO test data.
Based on AP-42 Table 3.3-1 TOC value for exhaust
ssume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier
ılfur content of natural gas 1.0 ppm based on a certified lab analysis using method ASTM D-3246.
ılfur content of diesel fuel assumed to be 0.5 wt. percent
ll Engine heat rates assumed to be 7,000 Btu/hp-hr
iesel fuel heating value assumed to be 137,000 Btu/gal

Bernice Lake Power Plant
Permit No. AQ0086TVP02 Rev2
Assessable Emissions for FY2016, based on 8760 hours of operation

ID	Emission Unit	Emission Unit Description	Rating		Factor Source	Emission Factor		Emissions (tpy)
NOx								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.04
						Total NOx Emissions:		**0.6**
SO2								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
						Total SO2 Emissions:		**0.0**
PM10								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.00
						Total PM10 Emissions:		**0.0**
CO								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.02
						Total CO Emissions:		**0.3**
VOC								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.00
						Total VOC Emissions:		**0.0**
						TOTAL ASSESSABLE EMISSIONS		**0**

Sulfur content of NG 1.0 ppm based on a certified lab analysis using method ASTM D-3246.

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

AEEC Bernice Lake Monthly 2014 Fuel Usage

	Unit 2 Natural Gas Usage (SCF)	Unit 3 Natural Gas Usage (SCF)	Unit 4 Natural Gas Usage (SCF)	Unit 2 Natural Gas Usage (MMBtu*)	Unit 3 Natural Gas Usage (MMBtu*)	Unit 4 Natural Gas Usage (MMBtu*)
January	8629000	9794000	0	8680.8	9852.8	0.0
February	37000	8000	1114000	37.2	8.0	1120.7
March	0	8768000	0	0.0	8820.6	0.0
April	0	2797000	0	0.0	2813.8	0.0
May	201000	1012000	47000	202.2	1018.1	47.3
June	9960000	2014000	2048000	10019.8	2026.1	2060.3
July	2127000	66000	22000	2139.8	66.4	22.1
August	0	7062000	47641000	0.0	7104.4	47926.8
September	2749000	66344000	42701000	2765.5	66742.1	42957.2
October	0	39612000	126271000	0.0	39849.7	127028.6
November	0	5358000	2084000	0.0	5390.1	2096.5
December	0	0	0	0.0	0.0	0.0
2014 Total	**23703000**	**142835000**	**221928000**	**23845**	**143692**	**223260**

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

March 11, 2016

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ADEC AQ

Certified Mail: 7015 1660 0000 8627 0711

Air Permits Program
Attn: Assessable Emission Estimates
Alaska Department of Environmental Conservation
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795

Re: Bernice Lake Power Plant – Annual Emissions Estimate for Fiscal Year 2017
Air Quality Operating Permit No. AQ0086TVP03

Dear Sir or Madame:

Enclosed are assessable emission estimates for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant based upon actual emissions emitted during the most recent calendar year. This estimate is submitted in accordance with Conditions 29.2 and 30 of Permit No. AQ0086TVP03. AEEC is requesting their assessed fee be based on this estimate rather than potential emissions.

The sources of the emission factors used in the calculations are provided in the attachment and include enforceable test methods and other emission factors from EPA's publication AP-42, Volume I.

If you have any questions or concerns about this report, please feel free to contact me at 335-6223 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

Certification of Responsible Official

"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."

Responsible Official: Jim Kingrey

Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Summary of Projected Fiscal Year (FY) 2017 Assessable Emissions

Bernice Lake Power Plant

Projected Air Contaminant Emissions (tons per year)					
Source Type	**NO_x**	**CO**	**PM**	**VOC**	**SO_2**
Regulated Significant, January 1 - June 30, 2015	2.2	2.3	0.3	0.0	2.9
Regulated Insignificant	0.6	0.3	0.0	0.0	0.0
Subtotals	2.8	2.6	0.4	0.1	2.9
Total Assessable Emissions	**8.7**				

- Projected assessable emissions are based on actual operation during Calendar Year 2015.
- Calculations based on source test factors, AP-42 emission factors and mass balances, as shown in attached spreadsheets.

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2017, based on actual operation in 2015

ID	Emission Unit	Emission Unit Description	Rating		FY2017 use based on actual emissions in 2015		Factor Source	Emission Factor		Emissions (tpy)
NOx										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	313	MMBtu	AP-42 Table 3.1-1	0.32	lb/MMBtu	0.1
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	14281	MMBtu	Source Test Factor[1]	0.244	lb/MMBtu	1.7
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2587	MMBtu	Source Test Factor[1]	0.222	lb/MMBtu	0.3
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.1
								Total NOx Emissions:		**2.2**
SO2										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	313	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.1
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	14281	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	2.4
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2587	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.4
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
								Total SO2 Emissions:		**2.9**
56545										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	313	MMBtu	AP-42 Table 3.1-2a	0.0066	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	14	MMscf	BACT limit	12	lb/hr	0.3
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	3	MMscf	BACT limit	12	lb/hr	0.1
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
								Total PM10 Emissions:		**0.3**
CO										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	313	MMBtu	AP-42 Table 3.1-1	0.082	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	14281	MMBtu	Source Test Factor[3]	0.2850	lb/MMBtu	2.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2587	MMBtu	Source Test Factor[3]	0.1980	lb/MMBtu	0.3
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
								Total CO Emissions:		**2.3**
VOC										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	313	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	14281	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2587	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
								Total VOC Emissions:		**0.0**

[1] Based on most recent 2012 source test
[2] Based on calendar year 2011 operation, because data for calendar year 2014 was unavailable
[3] Source test factors taken from January 2008 emissions test on Units 3 and 4. This is the most recent CO test data.
[4] Based on AP-42 Table 3.3-1 TOC value for exhaust
Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier
Sulfur content of natural gas 1.0 ppm based on a certified lab analysis using method ASTM D-3246.
Sulfur content of diesel fuel assumed to be 0.5 wt. percent
All Engine heat rates assumed to be 7,000 Btu/hp-hr
Diesel fuel heating value assumed to be 137,000 Btu/gal

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2017, based on 8760 hours of operation

ID	Emission Unit	Emission Unit Description	Rating		Factor Source	Emission Factor		Emissions (tpy)
NOx								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.04
						Total NOx Emissions:		**0.6**
SO2								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
						Total SO2 Emissions:		**0.0**
PM10								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.00
						Total PM10 Emissions:		**0.0**
CO								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.02
						Total CO Emissions:		**0.3**
VOC								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.00
						Total VOC Emissions:		**0.0**
						TOTAL ASSESSABLE EMISSIONS		**0**

Sulfur content of NG 1.0 ppm based on a certified lab analysis using method ASTM D-3246.

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

AEEC Bernice Lake Monthly 2015 Fuel Usage

	Unit 2 Natural Gas Usage	Unit 3 Natural Gas Usage	Unit 4 Natural Gas Usage	Unit 2 Natural Gas Usage	Unit 3 Natural Gas Usage	Unit 4 Natural Gas Usage
	(SCF)	(SCF)	(SCF)	(MMBtu*)	(MMBtu*)	(MMBtu*)
January	0	6086000	73000	0.0	6122.5	73.4
February	0	1557000	247000	0.0	1566.3	248.5
March	0	1155000	121000	0.0	1161.9	121.7
April	0	369000	0	0.0	371.2	0.0
May	0	0	0	0.0	0.0	0.0
June	0	4647000	0	0.0	4674.9	0.0
July	0	0	188000	0.0	0.0	189.1
August	0	199000	0	0.0	200.2	0.0
September	169000	0	1764000	170.0	0.0	1774.6
October	0	0	0	0.0	0.0	0.0
November	0	0	0	0.0	0.0	0.0
December	142000	183000	179000	142.9	184.1	180.1
2015 Total	**311000**	**14196000**	**2572000**	**313**	**14281**	**2587**

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

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3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

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Air Permits Program
Attn: Assessable Emission Estimate
Alaska Dept. of Environ. Conservation
410 Willoughby Avenue, Suite 303
Juneau, AK 99801-1795

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street ● Homer, Alaska 99603 ● (907) 235-8551

March 15, 2017

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Certified Mail: 7015 1660 0000 8627 0742

Air Permits Program
Attn: Assessable Emission Estimates
Alaska Department of Environmental Conservation
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795

Re: Bernice Lake Power Plant – Annual Emissions Estimate for Fiscal Year 2018
Air Quality Operating Permit No. AQ0086TVP03

Dear Sir or Madame:

Enclosed are assessable emission estimates for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant based upon actual emissions emitted during the most recent calendar year. This estimate is submitted in accordance with Conditions 29.2 and 30 of Permit No. AQ0086TVP03. AEEC is requesting their assessed fee be based on this estimate rather than potential emissions.

The sources of the emission factors used in the calculations are provided in the attachment and include enforceable test methods and other emission factors from EPA's publication AP-42, Volume I.

If you have any questions or concerns about this report, please feel free to contact me at (907) 335-6223 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

Certification of Responsible Official

"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."

Responsible Official: ______________________

Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Summary of Projected Fiscal Year (FY) 2018 Assessable Emissions

Bernice Lake Power Plant

Projected Air Contaminant Emissions (tons per year)					
Source Type	NO_x	CO	PM	VOC	SO_2
Regulated Significant, January 1 - December 31 2016	1.1	0.8	0.1	0.0	1.2
Regulated Insignificant	0.6	0.3	0.0	0.0	0.0
Subtotals	1.7	1.1	0.2	0.1	1.3
Total Assessable Emissions	**4.2**				

- Projected assessable emissions are based on actual operation during Calendar Year 2016.
- Calculations based on source test factors, AP-42 emission factors and mass balances, as shown in attached spreadsheets.

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2018, based on actual operation in 2016

ID	Emission Unit	Emission Unit Description	Rating		FY2018 use based on actual emissions in 2016		Factor Source	Emission Factor		Emissions (tpy)
NOx										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	1934	MMBtu	AP-42 Table 3.1-1	0.32	lb/MMBtu	0.3
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	3703	MMBtu	Source Test Factor[1]	0.244	lb/MMBtu	0.5
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	1713	MMBtu	Source Test Factor[1]	0.222	lb/MMBtu	0.2
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.1
								Total NOx Emissions:		**1.1**
SO2										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	1934	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.3
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	3703	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.6
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	1713	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.3
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
								Total SO2 Emissions:		**1.2**
PM10										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	1934	MMBtu	AP-42 Table 3.1-2a	0.0066	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	4	MMscf	BACT limit	12	lb/hr	0.1
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2	MMscf	BACT limit	12	lb/hr	0.0
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
								Total PM10 Emissions:		**0.1**
CO										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	1934	MMBtu	AP-42 Table 3.1-1	0.082	lb/MMBtu	0.1
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	3703	MMBtu	Source Test Factor[3]	0.2850	lb/MMBtu	0.5
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	1713	MMBtu	Source Test Factor[3]	0.1980	lb/MMBtu	0.2
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
								Total CO Emissions:		**0.8**
VOC										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	1934	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	3703	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	1713	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
								Total VOC Emissions:		**0.0**

[1] Based on most recent 2012 source test

[2] Based on calendar year 2011 operation, because data for calendar year 2016 was unavailable

[3] Source test factors taken from January 2008 emissions test on Units 3 and 4. This is the most recent CO test data.

[4] Based on AP-42 Table 3.3-1 TOC value for exhaust

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

Sulfur content of natural gas 1.0 ppm based on a certified lab analysis using method ASTM D-3246.

Sulfur content of diesel fuel assumed to be 0.5 wt. percent

All Engine heat rates assumed to be 7,000 Btu/hp-hr

Diesel fuel heating value assumed to be 137,000 Btu/gal

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2018, based on 8760 hours of operation

ID	Emission Unit	Emission Unit Description	Rating		Factor Source	Emission Factor		Emissions (tpy)
NOx								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.04
						Total NOx Emissions:		**0.6**
SO2								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
						Total SO2 Emissions:		**0.0**
PM10								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.00
						Total PM10 Emissions:		**0.0**
CO								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.02
						Total CO Emissions:		**0.3**
VOC								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.00
						Total VOC Emissions:		**0.0**
						TOTAL ASSESSABLE EMISSIONS		**0**

Sulfur content of NG 1.0 ppm based on a certified lab analysis using method ASTM D-3246.

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

AEEC Bernice Lake Monthly 2016 Fuel Usage

	Unit 2 Natural Gas Usage	Unit 3 Natural Gas Usage	Unit 4 Natural Gas Usage	Unit 2 Natural Gas Usage	Unit 3 Natural Gas Usage	Unit 4 Natural Gas Usage
	(SCF)	(SCF)	(SCF)	(MMBtu*)	(MMBtu*)	(MMBtu*)
January	0	0	0	0.0	0.0	0.0
February	68000	90000	72000	68.4	90.5	72.4
March	0	0	0	0.0	0.0	0.0
April	0	0	0	0.0	0.0	0.0
May	33000	44000	234000	33.2	44.3	235.4
June	0	0	0	0.0	0.0	0.0
July	26000	59000	38000	26.2	59.4	38.2
August	9000	10000	11000	9.1	10.1	11.1
September	0	0	0	0.0	0.0	0.0
October	1786000	662000	1198000	1796.7	666.0	1205.2
November	0	2816000	150000	0.0	2832.9	150.9
December	0	0	0	0.0	0.0	0.0
2016 Total	**1922000**	**3681000**	**1703000**	**1934**	**3703**	**1713**

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

April 30, 2018

ADEC
Division of Air Quality
Air Non-Point Mobile Sources Program
555 Cordova Street
Anchorage AK 99501

Re: Bernice Lake Power Plant – 2017 Triennial Point Source Emission Inventory
Air Quality Operating Permit No. AQ0086TVP03

To Whom It May Concern:

Enclosed is the 2017 Triennial Emission Inventory Report for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant. If you have any questions or concerns about this report, please feel free to contact me at 335-6176 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

Certification of Responsible Official

"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."

Responsible Official: Jim Kingrey

Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Stationary Source Detail		
ADEC ID	86	
Name	Bernice Lake Combustion Turbine (BCT) Plant	
Physical Location	53318 Chevron Refinery Road	
	Kenai, AK 99611	
	Lat 60.6969	Long -151.3844
	Description: Seward Meridian, S1/2, SE1/2 of Section 16, Township 7N, Range	
AFS ID	212200034	
Census Area	Kenai Peninsula Borough (122)	
Line of Business (NAICS)	221112	
	> Utilities	
	> Utilities	
	> Electric Power Generation, Transmission and Distribution	
	> Fossil Fuel Electric Power Generation	
Line of Business (SIC)	4911	
	> Electric, gas, and sanitary services	
	> Electric Services	
Owner Name & Address	Alaska Electric and Energy Cooperative	
	3977 Lake Street	
	Homer, AK 99603	

Emission Unit 1					
> Specifications					
ID	1		Design Capacity	263 MILLION BTU PER HOUR	
Description	Gas Turbine Unit #2				
Manufacturer	General Electric		Manufactured Year	1971	
Model Number	Frame 5 Model M		Serial Number	214378	
> Regulations					
Regulation/Description					
> Control Equipment					
Capture Efficiency (%)					
System Description					
Equipment Type(s)					
> Pollutants Controlled					
Pollutant Description				Reduction Efficiency (%)	
> Processes					
Process	Primary Process				
SCC Code	20100201				
	> Internal Combustion Engines				
	> Electric Generation				
	> Natural Gas				
	> Turbine				
Material Processed	Natural Gas				
Period Start	1/1/2017		Period End	12/31/2017	
Throughput					
Total		Summer %	Fall %	Winter %	Spring %
0.185	MMSCF				
Operational Schedule					
Days/Week	Hours/Day	Weeks/Period	Hours/Period		
			1.6		
Fuel Characteristics					
Heat Content (BTU/SCF)	Elem. Sulfur Content	H2S Sulfur Content	Ash Content		
1002.4	< 0.8% by weight	0.7 ppm			
Heating					
Heat Input (MMBTU/HR)		Heat Output		Heat Values Convention	
115.9					
Emissions					
Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)	3.00E-02	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-1.	2.782E-03
Ammonia (NH3)	3.200E+00	POUNDS	MMSCF	EPA Emission Factor (EPA WebFIRE)	2.960E-04
Nitrogen Oxides(NOX)	3.200E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-1.	2.967E-02
PM2.5 Primary (Condensable)(PM25-PRI)	4.700E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	4.358E-01
PM2.5 Primary (Filterable)(PM25-PRI)	1.900E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	1.762E-01
PM10 Primary (Filt + Cond)(PM10-PRI)	6.600e-003	POUNDS	MILLION BTUS	EPA Emission Factor (EPA WebFIRE)	6.120E-04
Sulfur Dioxide(SO2)	3.400e-003	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	3.153E-04
Volatile Organic Compounds(VOC)	2.100e-003	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	1.947E-04
Lead and lead compounds	No Data			EPA Emission Factors, AP-42, Table 3.1-2a.	
Process	Secondary Process				
SCC Code					
	>				
	>				
	>				
	>				
Material Processed					
Period Start	1/1/2017		Period End	12/31/2017	
Throughput					
Total		Summer %	Fall %	Winter %	Spring %
(#)	(Unit Type)				
Operational Schedule					
Days/Week	Hours/Day	Weeks/Period	Hours/Period		
Fuel Characteristics					
Heat Content	Elem. Sulfur Content	H2S Sulfur Content	Ash Content		
Heating					
Heat Input		Heat Output		Heat Values Convention	
Emissions					
Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)					
Nitrogen Oxides(NOX)					
PM10 Primary (Filt + Cond)(PM10-PRI)					
Sulfur Dioxide(SO2)					
Volatile Organic Compounds(VOC)					
> Release Points					
ID	Description			Type	Apportion %
1	GE Frame 5 Gas Turbine Stack			Vertical	100

Emission Unit 2

> Specifications					
ID	2		Design Capacity	324.5 MILLION BTU PER HOUR	
Description	Gas Turbine Unit #3				
Manufacturer	General Electric		Manufactured Year		
Model Number	Frame 5 Model PG5341		Serial Number	281663	
> Regulations					
Regulation/Description					
NSPS: Part 60, Subpart GG - Stationary Gas Turbines					
> Control Equipment					
Capture Efficiency (%)	0				
System Description					
Equipment Type(s)	Water Injection				
> Pollutants Controlled					
Pollutant Description				Reduction Efficiency (%)	
Nitrogen Oxides				0	
> Processes					
Process	Primary Process				
SCC Code	20100201				
	> Internal Combustion Engines				
	> Electric Generation				
	> Natural Gas				
	> Turbine				
Material Processed	Natural Gas				
Period Start	1/1/2017		Period End	12/31/2017	
Throughput					
Total		Summer %	Fall %	Winter %	Spring %
0.287	MMSCF	25	25	50	
Operational Schedule					
Days/Week	Hours/Day	Weeks/Period	Hours/Period		
			1.9		
Fuel Characteristics					
Heat Content	Elem. Sulfur Content	H2S Sulfur Content	Ash Content		
1002.4	< 0.8% by weight	0.7 ppm			
Heating					
Heat Input (MMBTU/HR)		Heat Output		Heat Values Convention	
151.4					
Emissions					
Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)	3.00E-02	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-1.	4.315E-03
Ammonia (NH3)	3.200E+00	POUNDS	MMSCF	EPA Emission Factor (EPA WebFIRE)	4.592E-04
Nitrogen Oxides(NOX)	2.440E-01	POUNDS	MILLION BTUS	Stack Test	3.510E-02
PM2.5 Primary (Condensable)(PM25-PRI)	4.700E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	6.761E-01
PM2.5 Primary (Filterable)(PM25-PRI)	1.900E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	2.733E-01
PM10 Primary (Filt + Cond)(PM10-PRI)	6.600e-003	POUNDS	MILLION BTUS	EPA Emission Factor (EPA WebFIRE)	9.494E-04
Sulfur Dioxide(SO2)	3.400e-003	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	4.891E-04
Volatile Organic Compounds(VOC)	2.100e-003	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	3.021E-04
Lead and lead compounds	No Data			EPA Emission Factors, AP-42, Table 3.1-2a.	
Process	Secondary Process				
SCC Code					
	>				
	>				
	>				
	>				
Material Processed					
Period Start	1/1/2017		Period End	12/31/2017	
Throughput					
Total		Summer %	Fall %	Winter %	Spring %
(#)	(Unit Type)				
Operational Schedule					
Days/Week	Hours/Day	Weeks/Period	Hours/Period		
Fuel Characteristics					
Heat Content	Elem. Sulfur Content	H2S Sulfur Content	Ash Content		
Heating					
Heat Input		Heat Output		Heat Values Convention	
Emissions					
Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)					
Nitrogen Oxides(NOX)					
PM10 Primary (Filt + Cond)(PM10-PRI)					
Sulfur Dioxide(SO2)					
Volatile Organic Compounds(VOC)					
> Release Points					
ID	Description			Type	Apportion %
2	Gas Turbine #3 Stack			Vertical	100

Emission Unit 3					
> Specifications					
ID	3		Design Capacity	324.5 MILLION BTU PER HOUR	
Description	Gas Turbine Unit #4				
Manufacturer	General Electric		Manufactured Year		
Model Number	Frame 5 Model PG5341		Serial Number	282020	
> Regulations					
Regulation/Description					
NSPS: Part 60, Subpart GG - Stationary Gas Turbines					
> Control Equipment					
Capture Efficiency (%)	0				
System Description					
Equipment Type(s)	Water Injection				
> Pollutants Controlled					
Pollutant Description				Reduction Efficiency (%)	
Nitrogen Oxides				0	
> Processes					
Process	Primary Process				
SCC Code	20100201				
	> Internal Combustion Engines				
	> Electric Generation				
	> Natural Gas				
	> Turbine				
Material Processed	Natural Gas				
Period Start	1/1/2017		Period End	12/31/2017	
Throughput					
Total		Summer %	Fall %	Winter %	Spring %
2.521	MMSCF	3	31	7	59
Operational Schedule					
Days/Week	Hours/Day	Weeks/Period	Hours/Period		
			11.9		
Fuel Characteristics					
Heat Content	Elem. Sulfur Content	H2S Sulfur Content	Ash Content		
1002.4	< 0.8% by weight	0.7 ppm			
Heating					
Heat Input (MMBTU/HR)		Heat Output		Heat Values Convention	
212.4					
Emissions					
Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)	3.00E-02	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-1.	3.791E-02
Ammonia (NH3)	3.200E+00	POUNDS	MMSCF	EPA Emission Factor (EPA WebFIRE)	4.034E-03
Nitrogen Oxides(NOX)	2.220E-01	POUNDS	MILLION BTUS	Stack Test	2.805E-01
PM2.5 Primary (Condensable)(PM25-PRI)	4.700E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	5.939E+00
PM2.5 Primary (Filterable)(PM25-PRI)	1.900E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	2.401E+00
PM10 Primary (Filt + Cond)(PM10-PRI)	6.600e-003	POUNDS	MILLION BTUS	EPA Emission Factor (EPA WebFIRE)	8.339E-03
Sulfur Dioxide(SO2)	3.400e-003	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	4.296E-03
Volatile Organic Compounds(VOC)	2.100e-003	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.1-2a.	2.653E-03
Lead and lead compounds	No Data			EPA Emission Factors, AP-42, Table 3.1-2a.	
Process	Secondary Process				
SCC Code					
	>				
	>				
	>				
	>				
Material Processed					
Period Start	1/1/2017		Period End	12/31/2017	
Throughput					
Total		Summer %	Fall %	Winter %	Spring %
(#)	(Unit Type)				
Operational Schedule					
Days/Week	Hours/Day	Weeks/Period	Hours/Period		
Fuel Characteristics					
Heat Content	Elem. Sulfur Content	H2S Sulfur Content	Ash Content		
Heating					
Heat Input		Heat Output		Heat Values Convention	
Emissions					
Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)					
Nitrogen Oxides(NOX)					
PM10 Primary (Filt + Cond)(PM10-PRI)					
Sulfur Dioxide(SO2)					
Volatile Organic Compounds(VOC)					
> Release Points					
ID	Description			Type	Apportion %
3	Gas Turbine #4 Stack			Vertical	100

Emission Unit 4

> Specifications

ID	4	Design Capacity	244 HORSEPOWER
Description	Blackstart Unit 2		
Manufacturer	Cummins	Manufactured Year	1971
Model Number	V785B300	Serial Number	

> Regulations

Regulation/Description
MACT: Part 63, Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines - Oil

> Control Equipment

Capture Efficiency (%)	0
System Description	
Equipment Type(s)	

> Pollutants Controlled

Pollutant Description	Reduction Efficiency (%)

> Processes

Process	Primary Process
SCC Code	20200102
	> Internal Combustion Engines
	> Industrial
	> Distillate Oil (Diesel)
	> Reciprocating
Material Processed	Diesel
Period Start	1/1/2017
Period End	12/31/2017

Throughput

Total		Summer %	Fall %	Winter %	Spring %
15	GALLONS				

Operational Schedule

Days/Week	Hours/Day	Weeks/Period	Hours/Period
			1.5

Fuel Characteristics

Heat Content (MBTU/GALLON)	Elem. Sulfur Content	H2S Sulfur Content	Ash Content
138	5.30E-07		

Heating

Heat Input (MBTU/HR)	Heat Output	Heat Values Convention
1380		

Emissions

Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)	9.500E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	9.833E-04
Ammonia (NH3)	8.000E-01	POUNDS	1000 GALLONS	EPA Emission Factor (EPA WebFIRE)	6.000E-06
Nitrogen Oxides(NOX)	4.410E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	4.564E-03
PM2.5 Primary (Condensable)(PM25-PRI)	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	
PM2.5 Primary (Filterable)(PM25-PRI)	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	
PM10 Primary (Filt + Cond)(PM10-PRI)	3.100E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	3.209E-04
Sulfur Dioxide(SO2)	2.900E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	3.002E-04
Volatile Organic Compounds(VOC)	3.500E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	3.623E-04
Lead and lead compounds	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	

Process	Secondary Process
SCC Code	
	>
	>
	>
	>
Material Processed	
Period Start	1/1/2017
Period End	12/31/2017

Throughput

Total		Summer %	Fall %	Winter %	Spring %
(#)	(Unit Type)				

Operational Schedule

Days/Week	Hours/Day	Weeks/Period	Hours/Period

Fuel Characteristics

Heat Content	Elem. Sulfur Content	H2S Sulfur Content	Ash Content

Heating

Heat Input	Heat Output	Heat Values Convention

Emissions

Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)					
Nitrogen Oxides(NOX)					
PM10 Primary (Filt + Cond)(PM10-PRI)					
Sulfur Dioxide(SO2)					
Volatile Organic Compounds(VOC)					

> Release Points

ID	Description	Type	Apportion %

Emission Unit 5					
> Specifications					
ID	5		Design Capacity	374 HORSEPOWER	
Description	Blackstart Unit 3				
Manufacturer	Detroit Engine		Manufactured Year	1978	
Model Number	7123-7000		Serial Number		
> Regulations					
Regulation/Description					
MACT: Part 63, Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines - Oil					
> Control Equipment					
Capture Efficiency (%)	0				
System Description					
Equipment Type(s)					
> Pollutants Controlled					
Pollutant Description				Reduction Efficiency (%)	
> Processes					
Process	Primary Process				
SCC Code	20200102				
	> Internal Combustion Engines				
	> Industrial				
	> Distillate Oil (Diesel)				
	> Reciprocating				
Material Processed	Diesel				
Period Start	1/1/2017		Period End	12/31/2017	
Throughput					
Total		Summer %	Fall %	Winter %	Spring %
22.5	GALLONS				
Operational Schedule					
Days/Week	Hours/Day	Weeks/Period	Hours/Period		
			1.5		
Fuel Characteristics					
Heat Content (MBTU/GALLON)	Elem. Sulfur Content	H2S Sulfur Content	Ash Content		
138	5.30E-07				
Heating					
Heat Input (MBTU/HR)		Heat Output		Heat Values Convention	
2070					
Emissions					
Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)	9.500E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	1.475E-03
Ammonia (NH3)	8.000E-01	POUNDS	1000 GALLONS	EPA Emission Factor (EPA WebFIRE)	9.000E-06
Nitrogen Oxides(NOX)	4.410E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	6.847E-03
PM2.5 Primary (Condensable)(PM25-PRI)	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	
PM2.5 Primary (Filterable)(PM25-PRI)	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	
PM10 Primary (Filt + Cond)(PM10-PRI)	3.100E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	4.813E-04
Sulfur Dioxide(SO2)	2.900E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	4.502E-04
Volatile Organic Compounds(VOC)	3.500E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	5.434E-04
Lead and lead compounds	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	
Process	Secondary Process				
SCC Code					
	>				
	>				
	>				
	>				
Material Processed					
Period Start	1/1/2017		Period End	12/31/2017	
Throughput					
Total		Summer %	Fall %	Winter %	Spring %
(#)	(Unit Type)				
Operational Schedule					
Days/Week	Hours/Day	Weeks/Period	Hours/Period		
Fuel Characteristics					
Heat Content	Elem. Sulfur Content	H2S Sulfur Content	Ash Content		
Heating					
Heat Input		Heat Output		Heat Values Convention	
Emissions					
Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)					
Nitrogen Oxides(NOX)					
PM10 Primary (Filt + Cond)(PM10-PRI)					
Sulfur Dioxide(SO2)					
Volatile Organic Compounds(VOC)					
> Release Points					
ID	Description			Type	Apportion %

Emission Unit 6

> Specifications

ID	6	Design Capacity	567 HORSEPOWER
Description	Blackstart Unit 4		
Manufacturer	Cummins	Manufactured Year	1981
Model Number	KT1150 C	Serial Number	

> Regulations

Regulation/Description
MACT: Part 63, Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines - Oil

> Control Equipment

Capture Efficiency (%)	0
System Description	
Equipment Type(s)	

> Pollutants Controlled

Pollutant Description	Reduction Efficiency (%)

> Processes

Process	Primary Process				
SCC Code	20200102				
	> Internal Combustion Engines				
	> Industrial				
	> Distillate Oil (Diesel)				
	> Reciprocating				
Material Processed	Diesel				
Period Start	1/1/2017		Period End	12/31/2017	

Throughput

Total		Summer %	Fall %	Winter %	Spring %
23.4	GALLONS				

Operational Schedule

Days/Week	Hours/Day	Weeks/Period	Hours/Period
			1.3

Fuel Characteristics

Heat Content (MBTU/GALLON)	Elem. Sulfur Content	H2S Sulfur Content	Ash Content
138	5.30E-07		

Heating

Heat Input (MBTU/HR)	Heat Output	Heat Values Convention
2484		

Emissions

Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)	9.500E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	1.534E-03
Ammonia (NH3)	8.000E-01	POUNDS	1000 GALLONS	EPA Emission Factor (EPA WebFIRE)	9.360E-06
Nitrogen Oxides(NOX)	4.410E+00	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	7.120E-03
PM2.5 Primary (Condensable)(PM25-PRI)	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	
PM2.5 Primary (Filterable)(PM25-PRI)	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	
PM10 Primary (Filt + Cond)(PM10-PRI)	3.100E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	5.005E-04
Sulfur Dioxide(SO2)	2.900E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	4.682E-04
Volatile Organic Compounds(VOC)	3.500E-01	POUNDS	MILLION BTUS	EPA Emission Factors, AP-42, Table 3.3-1.	5.651E-04
Lead and lead compounds	No Data			EPA Emission Factors, AP-42, Table 3.3-1.	

Process	Secondary Process				
SCC Code					
	>				
	>				
	>				
	>				
Material Processed					
Period Start	1/1/2017		Period End	12/31/2017	

Throughput

Total		Summer %	Fall %	Winter %	Spring %
(#)	(Unit Type)				

Operational Schedule

Days/Week	Hours/Day	Weeks/Period	Hours/Period

Fuel Characteristics

Heat Content	Elem. Sulfur Content	H2S Sulfur Content	Ash Content

Heating

Heat Input	Heat Output	Heat Values Convention

Emissions

Pollutant	Emission Factor	EF Numerator	EF Denominator	EF Source	Tons
Carbon Monoxide(CO)					
Nitrogen Oxides(NOX)					
PM10 Primary (Filt + Cond)(PM10-PRI)					
Sulfur Dioxide(SO2)					
Volatile Organic Compounds(VOC)					

> Release Points

ID	Description	Type	Apportion %

Release Point 01					
> Specifications					
ID	02		Type	Vertical	
Description	Gas Turbine #2 Stack				
> Stack Parameters					
Stack Height (ft)	Stack Diameter (ft)	Exit Gas Temp (F)	Exit Gas Velocity (fps)	Exit Gas Flow Rate (acfm)	
25	12	374	56	397819	
> Geographic Coordinate					
Latitude	60.6969	Longitude	-151.3844	Datum	NAD 1983
Base Elevation		Accuracy	10		
Description					

Release Point 03					
> Specifications					
ID	3		Type	Vertical	
Description	Gas Turbine #4 Stack				
> Stack Parameters					
Stack Height (ft)	Stack Diameter (ft)	Exit Gas Temp (F)	Exit Gas Velocity (fps)	Exit Gas Flow Rate (acfm)	
25	12	374	56	397819	
> Geographic Coordinate					
Latitude	60.6969	Longitude	-151.3844	Datum	NAD 1983
Base Elevation		Accuracy	10		
Description					

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

March 22, 2018

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ADEC AQ

Certified Mail: 7015 1660 0000 8627 0698

ADEC
Air Permits Program
ATTN: Assessable Emission Estimate
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795

Re: Bernice Lake Power Plant – Annual Emissions Estimate for Fiscal Year 2019
Air Quality Operating Permit No. AQ0086TVP03

Dear Sir or Madame:

Enclosed are assessable emission estimates for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant based upon actual emissions emitted during the most recent calendar year. This estimate is submitted in accordance with Conditions 29.2 and 30 of Permit No. AQ0086TVP03. AEEC is requesting their assessed fee be based on this estimate rather than potential emissions.

The sources of the emission factors used in the calculations are provided in the attachment and include enforceable test methods and other emission factors from EPA's publication AP-42, Volume I.

If you have any questions or concerns about this report, please feel free to contact me at (907) 335-6223 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

Certification of Responsible Official

"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."

Responsible Official: ______________________________

Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Summary of Projected Fiscal Year (FY) 2019 Assessable Emissions

Bernice Lake Power Plant

Projected Air Contaminant Emissions (tons per year)					
Source Type	NO_x	CO	PM	VOC	SO_2
Regulated Significant, January 1 - December 31 2017	0.5	0.3	0.1	0.0	0.5
Regulated Insignificant	0.6	0.3	0.0	0.0	0.0
Subtotals	1.1	0.6	0.1	0.0	0.5
Total Assessable Emissions	**2.3**				

- Projected assessable emissions are based on actual operation during Calendar Year 2017.
- Calculations based on source test factors, AP-42 emission factors and mass balances, as shown in attached spreadsheets.

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2019, based on actual operation in 2017

ID	Emission Unit	Emission Unit Description	Rating		FY2018 use based on actual emissions in 2017		Factor Source	Emission Factor		Emissions (tpy)
NOx										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	186	MMBtu	AP-42 Table 3.1-1	0.32	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	289	MMBtu	Source Test Factor[1]	0.244	lb/MMBtu	0.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2536	MMBtu	Source Test Factor[1]	0.222	lb/MMBtu	0.3
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.1
								Total NOx Emissions:		**0.5**
SO2										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	186	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	289	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2536	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.4
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
								Total SO2 Emissions:		**0.5**
PM10										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	186	MMBtu	AP-42 Table 3.1-2a	0.0066	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	1	MMscf	BACT limit	12	lb/hr	0.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	3	MMscf	BACT limit	12	lb/hr	0.1
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
								Total PM10 Emissions:		**0.1**
CO										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	186	MMBtu	AP-42 Table 3.1-1	0.082	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	289	MMBtu	Source Test Factor[3]	0.2850	lb/MMBtu	0.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2536	MMBtu	Source Test Factor[3]	0.1980	lb/MMBtu	0.3
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
								Total CO Emissions:		**0.3**
VOC										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	186	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	289	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2536	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
								Total VOC Emissions:		**0.0**

[1] Based on most recent 2012 source test
[2] Based on calendar year 2011 operation, because data for calendar year 2017 was unavailable
[3] Source test factors taken from January 2008 emissions test on Units 3 and 4. This is the most recent CO test data.
[4] Based on AP-42 Table 3.3-1 TOC value for exhaust
Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier
Sulfur content of natural gas 1.0 ppm based on a certified lab analysis using method ASTM D-3246.
Sulfur content of diesel fuel assumed to be 0.5 wt. percent
All Engine heat rates assumed to be 7,000 Btu/hp-hr
Diesel fuel heating value assumed to be 137,000 Btu/gal

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2019, based on 8760 hours of operation

ID	Emission Unit	Emission Unit Description	Rating		Factor Source	Emission Factor		Emissions (tpy)
NOx								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.04
						Total NOx Emissions:		**0.6**
SO2								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
						Total SO2 Emissions:		**0.0**
PM10								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.00
						Total PM10 Emissions:		**0.0**
CO								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.02
						Total CO Emissions:		**0.3**
VOC								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.00
						Total VOC Emissions:		**0.0**
						TOTAL ASSESSABLE EMISSIONS		**0**

Sulfur content of NG 1.0 ppm based on a certified lab analysis using method ASTM D-3246.

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

AEEC Bernice Lake Monthly 2017 Fuel Usage

	Unit 2 Natural Gas Usage (SCF)	Unit 3 Natural Gas Usage (SCF)	Unit 4 Natural Gas Usage (SCF)	Unit 2 Natural Gas Usage (MMBtu*)	Unit 3 Natural Gas Usage (MMBtu*)	Unit 4 Natural Gas Usage (MMBtu*)
January	57000	120000	42000	57.3	120.7	42.3
February	21000	27000	13000	21.1	27.2	13.1
March	0	0	0	0.0	0.0	0.0
April	0	0	304000	0.0	0.0	305.8
May	0	0	1367000	0.0	0.0	1375.2
June	0	0	0	0.0	0.0	0.0
July	0	0	0	0.0	0.0	0.0
August	47000	55000	42000	47.3	55.3	42.3
September	0	0	0	0.0	0.0	0.0
October	0	0	0	0.0	0.0	0.0
November	60000	64000	734000	60.4	64.4	738.4
December	0	21000	19000	0.0	21.1	19.1
2017 Total	**185000**	**287000**	**2521000**	**186**	**289**	**2536**

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

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AQ0086TVP03

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Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

Air Permits Program
Attn: Assessable Emission Estimate
Alaska Dept. of Environ. Conservation
410 Willoughby Avenue, Suite 303
Juneau, AK 99801-1795

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3977 LAKE STREET
HOMER, ALASKA 99603

TO:

Air Permits Program
Attn: Assessable Emission Estimate
Alaska Dept. Of Environ. Conservation
410 Willoughby Avenue, Suite 303
Juneau, AK 99801-1795

Received
MAR 26 2019
JNU SOA/DEC/DAS

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

March 20, 2019

Certified Mail: 7016 1870 0000 3406 3337

ADEC
Air Permits Program
ATTN: Assessable Emission Estimate
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795

Re: Bernice Lake Power Plant – Annual Assessable Emissions Estimate for Fiscal Year 2020
Air Quality Operating Permit No. AQ0086TVP03

Dear Sir or Madame:

Enclosed is the Annual Assessable Emissions Estimate for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant based upon actual emissions emitted during the most recent calendar year. This estimate is submitted in accordance with Conditions 29.2 and 30 of Permit No. AQ0086TVP03. AEEC is requesting their assessed fee be based on this estimate rather than potential emissions.

The sources of the emission factors used in the calculations are provided in the attachment and include enforceable test methods and other emission factors from EPA's publication AP-42, Volume I.

If you have any questions or concerns about this report, please feel free to contact me at (907) 335-6223 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

Certification of Responsible Official

"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."

Responsible Official: ______________________
Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Summary of Projected Fiscal Year (FY) 2020 Assessable Emissions

Bernice Lake Power Plant

Projected Air Contaminant Emissions (tons per year)					
Source Type	NO_x	CO	PM	VOC	SO_2
Regulated Significant, January 1 - December 31 2017	2.0	1.4	0.4	0.0	2.4
Regulated Insignificant	0.6	0.3	0.0	0.0	0.0
Subtotals	2.6	1.7	0.4	0.1	2.4
Total Assessable Emissions			7.1		

- Projected assessable emissions are based on actual operation during Calendar Year 2018.
- Calculations based on source test factors, AP-42 emission factors and mass balances, as shown in attached spreadsheets.

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2020, based on actual operation in 2018

ID	Emission Unit	Emission Unit Description	Rating		FY2019 use based on actual emissions in 2018		Factor Source	Emission Factor		Emissions (tpy)
NOx										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	5287	MMBtu	AP-42 Table 3.1-1	0.32	lb/MMBtu	0.8
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	6365	MMBtu	Source Test Factor[1]	0.244	lb/MMBtu	0.8
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2536	MMBtu	Source Test Factor[1]	0.222	lb/MMBtu	0.3
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.1
								Total NOx Emissions:		**2.0**
SO2										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	5287	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.9
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	6365	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	1.1
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2536	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.4
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
								Total SO2 Emissions:		**2.4**
PM10										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	5287	MMBtu	AP-42 Table 3.1-2a	0.0066	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	7	MMscf	BACT limit	12	lb/hr	0.1
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	13	MMscf	BACT limit	12	lb/hr	0.2
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
								Total PM10 Emissions:		**0.4**
CO										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	5287	MMBtu	AP-42 Table 3.1-1	0.082	lb/MMBtu	0.2
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	6365	MMBtu	Source Test Factor[3]	0.2850	lb/MMBtu	0.9
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2536	MMBtu	Source Test Factor[3]	0.1980	lb/MMBtu	0.3
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
								Total CO Emissions:		**1.4**
VOC										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	5287	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	6365	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2536	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.0
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
								Total VOC Emissions:		**0.0**

[1] Based on most recent 2012 source test

[2] Based on calendar year 2011 operation, because data for calendar year 2018 was unavailable

[3] Source test factors taken from January 2008 emissions test on Units 3 and 4. This is the most recent CO test data.

[4] Based on AP-42 Table 3.3-1 TOC value for exhaust

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

Sulfur content of natural gas 1.0 ppm based on a certified lab analysis using method ASTM D-3246.

Sulfur content of diesel fuel assumed to be 0.5 wt. percent

All Engine heat rates assumed to be 7,000 Btu/hp-hr

Diesel fuel heating value assumed to be 137,000 Btu/gal

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2020, based on 8760 hours of operation

ID	Emission Unit	Emission Unit Description	Rating		Factor Source	Emission Factor		Emissions (tpy)
NOx								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.04
						Total NOx Emissions:		**0.6**
SO2								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
						Total SO2 Emissions:		**0.0**
PM10								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.00
						Total PM10 Emissions:		**0.0**
CO								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.02
						Total CO Emissions:		**0.3**
VOC								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.00
						Total VOC Emissions:		**0.0**
						TOTAL ASSESSABLE EMISSIONS		**0**

Sulfur content of NG 1.0 ppm based on a certified lab analysis using method ASTM D-3246.
Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

AEEC Bernice Lake Monthly 2018 Fuel Usage

	Unit 2 Natural Gas Usage (SCF)	Unit 3 Natural Gas Usage (SCF)	Unit 4 Natural Gas Usage (SCF)	Unit 2 Natural Gas Usage (MMBtu*)	Unit 3 Natural Gas Usage (MMBtu*)	Unit 4 Natural Gas Usage (MMBtu*)
January	612000	805000	81000	615.7	809.8	81.5
February	0	0	0	0.0	0.0	0.0
March	48000	68000	66000	48.3	68.4	66.4
April	56000	72000	75000	56.3	72.4	75.5
May	80000	98000	100000	80.5	98.6	100.6
June	0	229000	11189000	0.0	230.4	11256.1
July	0	0	0	0.0	0.0	0.0
August	58000	81000	163000	58.3	81.5	164.0
September	75000	77000	73000	75.5	77.5	73.4
October	4118000	4726000	0	4142.7	4754.4	0.0
November	65000	58000	94000	65.4	58.3	94.6
December	143000	113000	180000	143.9	113.7	181.1
2017 Total	**5255000**	**6327000**	**12021000**	**5287**	**6365**	**12093**

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

March 19, 2020

Certified Mail: 7016 1870 0000 3406 3368

ADEC
Air Permits Program
ATTN: Assessable Emission Estimate
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795

Re: Bernice Lake Power Plant – Annual Assessable Emissions Estimate for Fiscal Year 2021
Air Quality Operating Permit No. AQ0086TVP03

Dear Sir or Madame:

Enclosed is the Annual Assessable Emissions Estimate for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant based upon actual emissions emitted during the most recent calendar year. This estimate is submitted in accordance with Conditions 29.2 and 30 of Permit No. AQ0086TVP03. AEEC is requesting their assessed fee be based on this estimate rather than potential emissions.

The sources of the emission factors used in the calculations are provided in the attachment and include enforceable test methods and other emission factors from EPA's publication AP-42, Volume I.

If you have any questions or concerns about this report, please feel free to contact me at (907) 335-6223 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

AEEC Bernice Lake Power Plant
Permit No. AQ0086TVP03
FY2021 Assessable Emission Estimate

Certification of Responsible Official

"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."

Responsible Official: Jim Kingrey

Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Summary of Projected Fiscal Year (FY) 2021 Assessable Emissions

Bernice Lake Power Plant

Projected Air Contaminant Emissions (tons per year)					
Source Type	NO_x	CO	PM	VOC	SO_2
Regulated Significant, January 1 - December 31 2017	38.1	32.5	4.7	0.3	50.8
Regulated Insignificant	0.6	0.3	0.0	0.0	0.0
Subtotals	38.7	32.8	4.7	0.4	50.8
Total Assessable Emissions	**127.1**				

- Projected assessable emissions are based on actual operation during Calendar Year 2019
- Calculations based on source test factors, AP-42 emission factors and mass balances, as shown in attached spreadsheets

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2021, based on actual operation in 2019

ID	Emission Unit	Emission Unit Description	Rating		FY2019 use based on actual emissions in 2019		Factor Source	Emission Factor		Emissions (tpy)
NOx										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	AP-42 Table 3.1-1	0.32	lb/MMBtu	9.5
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137253	MMBtu	Source Test Factor[1]	0.244	lb/MMBtu	16.7
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106089	MMBtu	Source Test Factor[1]	0.222	lb/MMBtu	11.8
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.1
								Total NOx Emissions:		**38.1**
SO2										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	9.9
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137253	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	23.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106089	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	17.8
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
								Total SO2 Emissions:		**50.8**
PM10										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	AP-42 Table 3.1-2a	0.0066	lb/MMBtu	0.2
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137	MMscf	BACT limit	12	lb/hr	2.5
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106	MMscf	BACT limit	12	lb/hr	2.0
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
								Total PM10 Emissions:		**4.7**
CO										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	AP-42 Table 3.1-1	0.082	lb/MMBtu	2.4
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137253	MMBtu	Source Test Factor[3]	0.2850	lb/MMBtu	19.6
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106089	MMBtu	Source Test Factor[3]	0.1980	lb/MMBtu	10.5
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
								Total CO Emissions:		**32.5**
VOC										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.1
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137253	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.1
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106089	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.1
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
								Total VOC Emissions:		**0.3**

[1] Based on most recent 2012 source test

[2] Based on calendar year 2011 operation, because data for calendar year 2018 was unavailable

[3] Source test factors taken from January 2008 emissions test on Units 3 and 4. This is the most recent CO test data.

[4] Based on AP-42 Table 3.3-1 TOC value for exhaust

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

Sulfur content of natural gas 1.0 ppm based on a certified lab analysis using method ASTM D-3246

Sulfur content of diesel fuel assumed to be 0.5 wt. percent

All Engine heat rates assumed to be 7,000 Btu/hp-hr

Diesel fuel heating value assumed to be 137,000 Btu/gal

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2021, based on 8760 hours of operation

ID	Emission Unit	Emission Unit Description	Rating		Factor Source	Emission Factor		Emissions (tpy)
NOx								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.04
						Total NOx Emissions:		**0.6**
SO2								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
						Total SO2 Emissions:		**0.0**
PM10								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.00
						Total PM10 Emissions:		**0.0**
CO								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.02
						Total CO Emissions:		**0.3**
VOC								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.00
						Total VOC Emissions:		**0.0**
						TOTAL ASSESSABLE EMISSIONS		**0**

Sulfur content of NG 1.0 ppm based on a certified lab analysis using method ASTM D-3246

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

AEEC Bernice Lake Monthly 2019 Fuel Usage

	Unit 2 Natural Gas Usage (SCF)	Unit 3 Natural Gas Usage (SCF)	Unit 4 Natural Gas Usage (SCF)	Unit 2 Natural Gas Usage (MMBtu*)	Unit 3 Natural Gas Usage (MMBtu*)	Unit 4 Natural Gas Usage (MMBtu*)
January	79000	87000	146000	79.5	87.5	146.9
February	0	0	0	0.0	0.0	0.0
March	26213000	104000	7580000	26370.3	104.6	7625.5
April	23173000	–0	0	23312.0	0.0	0.0
May	39000	73000	812000	39.2	73.4	816.9
June	4227000	722000	4008000	4252.4	726.3	4032.0
July	0	0	3679000	0.0	0.0	3701.1
August	1331000	15353000	29481000	1339.0	15445.1	29657.9
September	492000	88380000	24532000	495.0	88910.3	24679.2
October	2824000	30511000	0	2840.9	30694.1	0.0
November	519000	992000	542000	522.1	998.0	545.3
December	0	212000	34676000	0.0	213.3	34884.1
2019 Total	**58897000**	**136434000**	**105456000**	**59250**	**137253**	**106089**

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

Alaska Electric and Energy Cooperative, Inc.
3977 Lake Street • Homer, Alaska 99603 • (907) 235-8551

March 19, 2020

Certified Mail: 7016 1870 0000 3406 3368

ADEC
Air Permits Program
ATTN: Assessable Emission Estimate
410 Willoughby Ave., Suite 303
Juneau, AK 99801-1795

Re: Bernice Lake Power Plant – Annual Assessable Emissions Estimate for Fiscal Year 2021
Air Quality Operating Permit No. AQ0086TVP03

Dear Sir or Madame:

Enclosed is the Annual Assessable Emissions Estimate for Alaska Electric & Energy Cooperative's (AEEC's) Bernice Lake Power Plant based upon actual emissions emitted during the most recent calendar year. This estimate is submitted in accordance with Conditions 29.2 and 30 of Permit No. AQ0086TVP03. AEEC is requesting their assessed fee be based on this estimate rather than potential emissions.

The sources of the emission factors used in the calculations are provided in the attachment and include enforceable test methods and other emission factors from EPA's publication AP-42, Volume I.

If you have any questions or concerns about this report, please feel free to contact me at (907) 335-6223 or send email to blinton@homerelectric.com.

Best Regards,

Bruce Linton
Environmental Compliance Officer
Homer Electric Association, Inc.

Certification of Responsible Official

"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."

Responsible Official: Jim Kingrey

Jim Kingrey
Plant Superintendent
Alaska Electric & Energy Cooperative, Inc.

Summary of Projected Fiscal Year (FY) 2021 Assessable Emissions

Bernice Lake Power Plant

Projected Air Contaminant Emissions (tons per year)					
Source Type	NO_x	CO	PM	VOC	SO_2
Regulated Significant, January 1 - December 31 2017	38.1	32.5	4.7	0.3	50.8
Regulated Insignificant	0.6	0.3	0.0	0.0	0.0
Subtotals	38.7	32.8	4.7	0.4	50.8
Total Assessable Emissions	**127.1**				

- Projected assessable emissions are based on actual operation during Calendar Year 2019
- Calculations based on source test factors, AP-42 emission factors and mass balances, as shown in attached spreadsheets

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2021, based on actual operation in 2019

ID	Emission Unit	Emission Unit Description	Rating		FY2019 use based on actual emissions in 2019		Factor Source	Emission Factor		Emissions (tpy)
NOx										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	AP-42 Table 3.1-1	0.32	lb/MMBtu	9.5
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137253	MMBtu	Source Test Factor[1]	0.244	lb/MMBtu	16.7
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106089	MMBtu	Source Test Factor[1]	0.222	lb/MMBtu	11.8
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.031	lb/hp/hr	0.1
								Total NOx Emissions:		**38.1**
SO2										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	9.9
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137253	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	23.0
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106089	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	17.8
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0
								Total SO2 Emissions:		**50.8**
PM10										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	AP-42 Table 3.1-2a	0.0066	lb/MMBtu	0.2
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137	MMscf	BACT limit	12	lb/hr	2.5
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106	MMscf	BACT limit	12	lb/hr	2.0
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.0022	lb/hp/hr	0.0
								Total PM10 Emissions:		**4.7**
CO										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	AP-42 Table 3.1-1	0.082	lb/MMBtu	2.4
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137253	MMBtu	Source Test Factor[3]	0.2850	lb/MMBtu	19.6
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106089	MMBtu	Source Test Factor[3]	0.1980	lb/MMBtu	10.5
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1	0.00668	lb/hp/hr	0.0
								Total CO Emissions:		**32.5**
VOC										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59250	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.1
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137253	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.1
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106089	MMBtu	AP-42 Table 3.1-2a	0.0021	lb/MMBtu	0.1
5		Cummins Engine Model V785B300	244.0	Hp	4	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
6		Detroit Engine Model 7123-7000	374.0	Hp	5	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
7		Cummins Engine Model KT1150C	567.0	Hp	10	hr/yr[2]	AP-42 Table 3.3-1[4]	0.002	lb/hp-hr	0.0
								Total VOC Emissions:		**0.3**

[1] Based on most recent 2012 source test

[2] Based on calendar year 2011 operation, because data for calendar year 2018 was unavailable

[3] Source test factors taken from January 2008 emissions test on Units 3 and 4. This is the most recent CO test data.

[4] Based on AP-42 Table 3.3-1 TOC value for exhaust

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

Sulfur content of natural gas 1.0 ppm based on a certified lab analysis using method ASTM D-3246

Sulfur content of diesel fuel assumed to be 0.5 wt. percent

All Engine heat rates assumed to be 7,000 Btu/hp-hr

Diesel fuel heating value assumed to be 137,000 Btu/gal

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions for FY2021, based on 8760 hours of operation

ID	Emission Unit	Emission Unit Description	Rating		Factor Source	Emission Factor		Emissions (tpy)
NOx								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.11
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	94	lb/MMscf	0.04
						Total NOx Emissions:		**0.6**
SO2								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	Engineering Calc.	0.00	lb/MMBtu	0.00
						Total SO2 Emissions:		**0.0**
PM10								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	7.6	lb/MMscf	0.00
						Total PM10 Emissions:		**0.0**
CO								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.05
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-1	40	lb/MMscf	0.02
						Total CO Emissions:		**0.3**
VOC								
8	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
9	IEU	Heater Model PA200SFM	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
10	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
11	IEU	Heater Model PA105AB	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
12	IEU	Heater Model PAH240SF	0.3	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.01
13	IEU	Heater Model BT270A820	0.1	MMBtu/hr	AP-42 Table 1.4-2	5.5	lb/MMscf	0.00
						Total VOC Emissions:		**0.0**
						TOTAL ASSESSABLE EMISSIONS		**0**

Sulfur content of NG 1.0 ppm based on a certified lab analysis using method ASTM D-3246

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

AEEC Bernice Lake Monthly 2019 Fuel Usage

	Unit 2 Natural Gas Usage (SCF)	Unit 3 Natural Gas Usage (SCF)	Unit 4 Natural Gas Usage (SCF)	Unit 2 Natural Gas Usage (MMBtu*)	Unit 3 Natural Gas Usage (MMBtu*)	Unit 4 Natural Gas Usage (MMBtu*)
January	79000	87000	146000	79.5	87.5	146.9
February	0	0	0	0.0	0.0	0.0
March	26213000	104000	7580000	26370.3	104.6	7625.5
April	23173000	0	0	23312.0	0.0	0.0
May	39000	73000	812000	39.2	73.4	816.9
June	4227000	722000	4008000	4252.4	726.3	4032.0
July	0	0	3679000	0.0	0.0	3701.1
August	1331000	15353000	29481000	1339.0	15445.1	29657.9
September	492000	88380000	24532000	495.0	88910.3	24679.2
October	2824000	30511000	0	2840.9	30694.1	0.0
November	519000	992000	542000	522.1	998.0	545.3
December	0	212000	34676000	0.0	213.3	34884.1
2019 Total	**58897000**	**136434000**	**105456000**	**59250**	**137253**	**106089**

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

7016 1970 0000 3406 3368

FIRST-CLASS

PITNEY BOWES

US POSTAGE

02 1P $ 007.20[0]

0002104666 MAR 27 2020

MAILED FROM ZIP CODE 99611

FROM:

ALASKA ELECTRIC & ENERGY CO-OP
3977 LAKE STREET
HOMER, ALASKA 99603

TO:

Air Permits Program
Attn: Assessable Emission Estimate
Alaska Dept. Of Environ. Conservation
410 Willoughby Avenue, Suite 303
Juneau, AK 99801-1795

Received
MAR 31 2020
JNU SOA/DEC/DAS

Bernice Lake Power Plant
Permit No. AQ0086TVP03
Assessable Emissions Estimates

ID	Emission Unit	Emission Unit Description	Rating		Fuel use based on actual emissions		Factor Source	Emission Factor		Emissions (tpy)
2019										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	59,250	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.0050
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	137,253	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.0115
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	106,089	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.0089
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0017
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0033
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0101
								Total SO2 Emissions:		**0.041**
2018										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	5,287	MMBtu	Engineering Calc.	0.00017	lb/MMBtu	0.0004
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	6,365	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.001
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2,536	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.000
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.002
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.003
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.010
								Total SO2 Emissions:		**0.016**
2017										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	186	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.00002
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	289	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.00002
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2,536	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.0002
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0017
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0033
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.0101
								Total SO2 Emissions:		**0.015**
2016										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	1,934	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.000
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	3,703	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.000
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	1,713	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.000
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.002
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.003
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.010
								Total SO2 Emissions:		**0.016**
2015										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	313	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.000
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	14,281	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.001
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	2,587	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.000
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.002
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.003
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.010
								Total SO2 Emissions:		**0.017**
2014										
2	1	GE Frame 5 Turbine Model M	263.0	MMBtu/hr	56,545	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.005
3	2	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	244,349	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.021
4	3	GE Frame 5 Turbine Model PG5341	324.5	MMBtu/hr	336,182	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.028
5		Cummins Engine Model V785B300	1.7	MMBtu/hr	4	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.002
6		Detroit Engine Model 7123-7000	2.6	MMBtu/hr	5	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.003
7		Cummins Engine Model KT1150C	4.0	MMBtu/hr	10	hr/yr[2]	Engineering Calc.	0.511	lb/MMBtu	0.010
								Total SO2 Emissions:		**0.069**

Bernice Lake Power Plant
Emission Inventory: Note that 2014 shows actual emissions in column k and EE reported values in column L

ID	Emission Unit	Emission Unit Description	Fuel Use		Fuel use 1,002.4 MMBtu/MMscf 0.138 MMBTu/Gal		Factor Source	Emission Factor		Emissions (tpy)
2017										
2	1	GE Frame 5 Turbine Model M	0.185	MMscf	185	MMBtu	Engineering Calc.	0.0034	lb/MMBtu	0.00032
3	2	GE Frame 5 Turbine Model PG5341	0.287	MMscf	288	MMBtu	Engineering Calc.	0.0034	lb/MMBtu	0.00049
4	3	GE Frame 5 Turbine Model PG5341	2.521	MMscf	2,527	MMBtu	Engineering Calc.	0.0034	lb/MMBtu	0.00430
5		Cummins Engine Model V785B300	15.0	gal	2.1	MMBtu	Engineering Calc.	0.290	lb/MMBtu	0.00030
6		Detroit Engine Model 7123-7000	22.5	gal	3.1	MMBtu	Engineering Calc.	0.290	lb/MMBtu	0.00045
7		Cummins Engine Model KT1150C	23.4	gal	3.2	MMBtu	Engineering Calc.	0.290	lb/MMBtu	0.00047
								Total SO2 Emissions:		**0.0063**

ID	Emission Unit	Emission Unit Description	Fuel Use		Fuel use 1,020 MMBtu/MMscf 0.138 MMBTu/Gal		Factor Source	Emission Factor		Emissions (tpy)	Reported Value in 2014 Emission Inventory (tons)
2014											
2	1	GE Frame 5 Turbine Model M	23.7	MMscf	24,174	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.00205	9.5
3	2	GE Frame 5 Turbine Model PG5341	142.8	MMscf	145,656	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.01238	41.0
4	3	GE Frame 5 Turbine Model PG5341	388.5	MMscf	396,270	MMBtu	Engineering Calc.	0.0002	lb/MMBtu	0.03368	56.4
5		Cummins Engine Model V785B300		gal	-	MMBtu	Engineering Calc.		lb/MMBtu		
6		Detroit Engine Model 7123-7000		gal	-	MMBtu	Engineering Calc.		lb/MMBtu		
7		Cummins Engine Model KT1150C		gal	-	MMBtu	Engineering Calc.		lb/MMBtu		
								Total SO2 Emissions:		**0.048**	106.9

*Note that source reported SO2 emissions in lbs instead of tons

[1] Based on most recent 2012 source test
[2] Based on calendar year 2011 operation, because data for calendar year 2018 was unavailable
[3] Source test factors taken from January 2008 emissions test on Units 3 and 4. This is the most recent CO test data.
[4] Based on AP-42 Table 3.3-1 TOC value for exhaust
Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier
Sulfur content of natural gas 1.0 ppm based on a certified lab analysis using method ASTM D-3246
Sulfur content of diesel fuel assumed to be 0.5 wt. percent
All Engine heat rates assumed to be 7,000 Btu/hp-hr
Diesel fuel heating value assumed to be 137,000 Btu/gal

AEEC Bernice Lake Monthly 2019 Fuel Usage

	Unit 2 Natural Gas Usage	Unit 3 Natural Gas Usage	Unit 4 Natural Gas Usage	Unit 2 Natural Gas Usage	Unit 3 Natural Gas Usage	Unit 4 Natural Gas Usage
	(SCF)	(SCF)	(SCF)	(MMBtu*)	(MMBtu*)	(MMBtu*)
January	79000	87000	146000	79.5	87.5	146.9
February	0	0	0	0.0	0.0	0.0
March	26213000	104000	7580000	26370.3	104.6	7625.5
April	23173000	0	0	23312.0	0.0	0.0
May	39000	73000	812000	39.2	73.4	816.9
June	4227000	722000	4008000	4252.4	726.3	4032.0
July	0	0	3679000	0.0	0.0	3701.1
August	1331000	15353000	29481000	1339.0	15445.1	29657.9
September	492000	88380000	24532000	495.0	88910.3	24679.2
October	2824000	30511000	0	2840.9	30694.1	0.0
November	519000	992000	542000	522.1	998.0	545.3
December	0	212000	34676000	0.0	213.3	34884.1
2019 Total	**58897000**	**136434000**	**105456000**	**59250**	**137253**	**106089**

Assume 1006 Btu/scf HHV for natural gas, as characterized by the gas supplier

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APR 04 2016

ADEC AQ

DEPARTMENT OF THE AIR FORCE
13th SPACE WARNING SQUADRON (AFSPC)
CLEAR AFS ALASKA

MEMORANDUM FOR ADEC
AIR PERMITS PROGRAM
ATTN: ASSESSABLE EMISSIONS ESTIMATE
410 WILLOUGHBY AVE.
JUNEAU, AK 99801-1795

FROM: 13 SWS/CC
200 A Street Stop 1
Clear AFS AK 99704-5360

SUBJECT: Clear Air Force Station Permit No. 000318TVP03, Rev 3 – Fee Assessment

1. The following information is submitted pursuant to the Clear AFS Air Quality permit Condition 70, Fee Requirements.

2. Clear AFS's assessable emissions are based on the facility's projected annual rate of emissions, from stationary and fugitive emission sources, and are demonstrated by material balance calculations, emission factors from the EPA's publication AP-42, and other methods and calculations approved by the EPA. Clear AFS has begun implementation of an Air Force Air Quality database called APIMS (Air Program Information Management System). Without full implementation and numerous EU ID changes recently occurring at Clear AFS, a comprehensive AEI was not feasible or viable for CY2015. A report generated through APIMS contains the 2014 Air Emissions Inventory without the coal associated sources and a projection for the new EUs based on two months of data and/or hours projections for Clear AFS. Attached is supportive documentation.

3. Estimated emissions of criteria pollutants during the period January 2016—December 2016 are estimated at 39.39 tons. Hazardous Air Pollutants (HAPs) emitted over this time period were estimated at .51 tons. These estimates will be used as a basis for fee assessment.

4. 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.

5. If you have any technical questions regarding the above information or need additional information, please contact our Environmental Coordinator Mr. John Basile at (907) 585-6398.

BURCH.JASON.B.1187343980 Digitally signed by BURCH.JASON.B.1187343980 DN: c=US, o=U.S. Government, ou=DoD, ou=PKI, ou=USAF, cn=BURCH.JASON.B.1187343980 Date: 2016.03.31 05:52:42 -08'00'

JASON B. BURCH, Lt Col, USAF
Commander, 13th Space Warning Squadron

Attachment:
2016 Clear AFS Criteria Pollutant Emissions Projection

cc:
21 CES/CEIE
13 SWS / ENV files

SENTINELS OF SPACE

Clear AFS - Projected Actual Emissions 2016

Source Category		Tons Emitted						
Code	Name	CO	NOx	PM10	PM2.5	SOx	Total VOC	Total HAPS
ABCL	ABRASIVE CLEANING	-	-	0.0004	0.0004	-	-	-
AST	ABOVE GROUND STORAGE TANKS	-	-	-	-	-	0.0591	0.000725
CHEM	MISC CHEMICAL USAGE	-	-	-	-	-	0.0918	0.092704
ECOM	EXTERNAL COMBUSTION	1.4862	5.9448	0.3210	0.2467	0.0032	0.1011	0.386528
FDSP	FUEL DISPENSING	-	-	-	-	-	0.1170	0.003772
FIRE	FIRE TRAINING	0.0264	0.0008	0.0032	0.0032	-	0.0036	-
FLD	FUEL LOADING RACKS	-	-	-	-	-	0.0009	0.000012
ICOM	INTERNAL COMBUSTION	9.3025	19.6159	0.6331	0.6331	0.0369	1.1268	0.019809
WELD	WELDING/SOLDERING/CUTTING	-	-	0.0051	0.0051	-	-	0.001842
WOOD	WOODWORKING	-	-	0.0196	0.0149	-	-	-
	Total	10.81511	25.56145	0.98243	0.903351	0.040047	1.500284	0.505392

RECEIVED
MAR 28 2017
ADEC AQ

DEPARTMENT OF THE AIR FORCE
13th SPACE WARNING SQUADRON (AFSPC)
CLEAR AFS ALASKA

8 Mar 17

MEMORANDUM FOR ADEC
AIR PERMITS PROGRAM
ATTN: ASSESSABLE EMISSIONS ESTIMATE
410 WILLOUGHBY AVE.
JUNEAU, AK 99801-1795

FROM: 13 SWS/CC
200 A Street Stop 1
Clear AFS AK 99704-5360

SUBJECT: Clear Air Force Station Permit No. 000318TVP03, Rev 3 – Fee Assessment

1. The following information is submitted pursuant to the Clear AFS Air Quality permit Condition 70, Fee Requirements.

2. Clear AFS's assessable emissions are based on the facility's projected annual rate of emissions, from stationary and fugitive emission sources, and are demonstrated by material balance calculations, emission factors from the EPA's publication AP-42, and other methods and calculations approved by the EPA. Attached is the supportive documentation extracted from the 2016 Air Emissions Inventory for Clear AFS.

3. Estimated emissions of criteria pollutants during the period January 2016—December 2016 are estimated at 19.88 tons. Hazardous Air Pollutants (HAPs) emitted over this time period were estimated at .41 tons. These estimates will be used as a basis for fee assessment.

4. 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.

5. If you have any technical questions regarding the above information or need additional information, please contact our Environmental Coordinator Mr. John Basile at (907) 585-6398.

BUDNICK.JASON.J ON.1136245933
Digitally signed by BUDNICK.JASON.JON.1136245933
DN: c=US, o=U.S. Government, ou=DoD, ou=PKI, ou=USAF, cn=BUDNICK.JASON.JON.1136245933
Date: 2017.03.14 14:06:46 -08'00'

JASON J. BUDNICK, Lt Col, USAF
Commander

Attachment:
2016 Clear AFS Criteria Pollutant Emissions

cc:
21 CES/CEIE
13 SWS/ENV files

SENTINELS OF SPACE

2016 CRITERIA POLLUTANT EMISSIONS

JAN-16 to DEC-16

Report Type: COMPREHENSIVE STATIONARY AEI

CLEAR AFS

Source Category		Tons Emitted						
Code	Name	CO	NOx	PM 10	PM 2.5	SOx	Total VOC	Total HAPs
ABCL	ABRASIVE CLEANING	-	-	0.000011	0.00001	-	-	-
AST	ABOVE GROUND STORAGE TANKS	-	-	-	-	-	0.078235	0.00108
CHEM	MISC CHEMICAL USAGE	-	-	-	-	-	0.744116	0.060668
DEGR	DEGREASING/SOLVENT CLEANING	-	-	-	-	-	0.07582	-
ECOM	EXTERNAL COMBUSTION	2.918421	7.703274	0.247525	0.190227	3.150934	0.095648	0.348074
FIRE	FIRE TRAINING	0.0091	0.00026	0.001106	0.001106	-	0.001236	-
FLD	FUEL LOADING RACKS	-	-	-	-	-	0.000374	0.000036
ICOM	INTERNAL COMBUSTION	1.436849	2.770953	0.099242	0.099242	0.020884	0.189559	0.003221
ROCK	ROCK CRUSHING OPERATION	-	-	0.038195	0.00577	-	-	-
WELD	WELDING/SOLDERING/CUTTING	-	-	0.004121	0.004121	-	-	0.00149
WOOD	WOODWORKING	-	-	0.001098	0.000834	-	-	-
	Total	**4.36437**	**10.474487**	**0.391298**	**0.30131**	**3.171818**	**1.184988**	**0.414569**

Rep-criteria_pollutant **For Official Use Only** Date Printed: 2017/03/07 Page: 1

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PLACE STICKER AT TOP OF ENVELOPE TO THE RIGHT OF THE RETURN ADDRESS. FOLD AT DOTTED LINE

CERTIFIED MAIL™

FROM: BAE/ENV
200 A st. Stop 500
Clear, AK 99704

RECEIVED
MAR 28 2017
JUNEAU / DAS

TO: ADEC
Air Permits Program
Attn: Assessable Emissions Estimate
410 Willoughby Ave.
Juneau, AK 99801-1795

DEPARTMENT OF THE AIR FORCE
13th SPACE WARNING SQUADRON (AFSPC)
CLEAR AFS ALASKA

29 Mar 2019

MEMORANDUM FOR ADEC
AIR PERMITS PROGRAM
ATTN: ASSESSABLE EMISSIONS ESTIMATE
410 WILLOUGHBY AVE, STE 303
PO Box 111800
JUNEAU, AK 99811-1800

FROM: 13 SWS/CC
200 A Street Stop 1
Clear AFS AK 99704-5360

SUBJECT: Clear Air Force Station Permit No. 000318TVP04 – Fee Assessment

1. The following information is submitted pursuant to the Clear AFS Air Quality permit Condition 53, Fee Requirements.

2. Clear AFS's assessable emissions are based on the facility's projected annual rate of emissions, from stationary and fugitive emission sources, and are demonstrated by material balance calculations, emission factors from the EPA's publication AP-42, and other methods and calculations approved by the EPA. Attached is the supportive documentation extracted from the 2018 Air Emissions Inventory for Clear AFS.

3. Estimated emissions of criteria pollutants during the period January 2018—December 2018 are estimated at 14.6 tons. Hazardous Air Pollutants (HAPs) emitted over this time period were estimated at .33 tons. These estimates will be used as a basis for fee assessment.

4. 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.

5. If you have any technical questions regarding the above information or need additional information, please contact our Environmental Coordinator Mr. John Basile at (907) 585-6398.

JEFFREY L. RUTHERFORD, Lt Col, USAF
Commander

Attachment:
2018 Clear AFS Criteria Pollutant Emissions

cc:
21 CES/CEIE
InDyne Inc / ENV files

2018 CRITERIA POLLUTANT EMISSIONS

JAN-18 to DEC-18

Report Type: COMPREHENSIVE STATIONARY AEI

CLEAR AFS

Source Category		Tons Emitted						
Code	**Name**	**CO**	**NOx**	**PM 10**	**PM 2.5**	**SOx**	**Total VOC**	**Total HAPs**
ABCL	ABRASIVE CLEANING	-	-	0	0	-	-	-
AST	ABOVE GROUND STORAGE TANKS	-	-	-	-	-	0.083745	0.000975
CHEM	MISC CHEMICAL USAGE	-	-	-	-	-	0.043443	0.014436
DEGR	DEGREASING/SOLVENT CLEANING	-	-	-	-	-	0	-
ECOM	EXTERNAL COMBUSTION	1.152658	4.61062	0.248974	0.191339	0.049795	0.078379	0.299796
FDSP	FUEL DISPENSING	-	-	-	-	-	0.161932	0.006536
FIRE	FIRE TRAINING	0.0679	0.00194	0.008245	0.008245	-	0.009215	-
FLD	FUEL LOADING RACKS	-	-	-	-	-	0.000432	0.000042
ICOM	INTERNAL COMBUSTION	2.561237	4.737354	0.162626	0.162626	0.023699	0.327826	0.005669
PEST	HERBICIDE/PESTICIDE APPLICATION	-	-	-	-	-	0	-
WELD	WELDING/SOLDERING/CUTTING	-	-	0.004121	0.004121	-	-	0.00149
WOOD	WOODWORKING	-	-	0.001096	0.001096	-	-	-
	Total	**3.781795**	**9.349914**	**0.425062**	**0.367427**	**0.073494**	**0.704972**	**0.328944**

DEPARTMENT OF THE AIR FORCE
13TH SPACE WARNING SQUADRON (USSF)

14 April 2020

MEMORANDUM FOR ADEC
AIR PERMITS PROGRAM
ATTN: ASSESSABLE EMISSIONS ESTIMATE
410 WILLOUGHBY AVE, STE 303
PO Box 111800
JUNEAU AK 99811-1800

FROM: 13 SWS/CC
200 A Street Stop 1
Clear AFS AK 99704-5360

SUBJECT: Clear Air Force Station Permit No. 000318TVP04 – Fee Assessment

1. The following information is submitted pursuant to the Clear AFS Air Quality permit Condition 53, Fee Requirements.

2. Clear AFS's assessable emissions are based on the facility's projected annual rate of emissions, from stationary and fugitive emission sources, and are demonstrated by material balance calculations, emission factors from the EPA's publication AP-42, and other methods and calculations approved by the EPA. Attached is the supportive documentation extracted from the 2019 Air Emissions Inventory for Clear AFS.

3. Estimated emissions of criteria pollutants during the period January 2019—December 2019 are estimated at 10.6 tons. Hazardous Air Pollutants (HAPs) emitted over this time period were estimated at 0.87 tons. These estimates will be used as a basis for fee assessment.

4. 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.

5. If you have any technical questions regarding the above information or need additional information, please contact our Environmental Coordinator Mr. John Basile at (907) 585-6398.

SHAWN P. LEE, Lt Col, USAF
Commander

CRITERIA POLLUTANT EMISSIONS
2019/01/01 to 2019/12/31
Comprehensive Stationary AEI

CLEAR AFS

Source Category		Tons Emitted						
Code	Name	CO	NOx	PM 10	PM 2.5	SOx	Total VOCs	Total HAPs
ABCL	ABRASIVE CLEANING	-	-	-	-	-	-	-
AST	ABOVE GROUND STORAGE TANKS	-	-	-	-	-	0.036495	0.001275
CHEM	MISC CHEMICAL USAGE	-	-	-	-	-	0.332214	0.505459
DEGR	DEGREASING/SOLVENT CLEANING	-	-	-	-	-	-	-
ECOM	EXTERNAL COMBUSTION	1.303965	5.307630	0.281657	0.216456	0.057041	0.088670	0.338938
FDSP	FUEL DISPENSING	-	-	-	-	-	0.201312	0.008128
FIRE	FIRE TRAINING	0.015750	0.000450	0.001913	0.001913	-	0.002138	-
FLD	FUEL LOADING RACKS	-	-	-	-	-	0.000336	0.000034
ICOM	INTERNAL COMBUSTION	0.838004	1.657998	0.062720	0.062720	0.001814	0.058497	0.000785
PEST	HERBICIDE/PESTICIDE APPLICATION	-	-	-	-	-	-	-
WELD	WELDING/SOLDERING/CUTTING	-	-	0.044921	0.044921	-	-	0.016232
WOOD	WOODWORKING	-	-	0.000687	0.000687	-	-	-
	Total:	**2.157719**	**6.966078**	**0.391898**	**0.326697**	**0.058855**	**0.719662**	**0.870851**

Department of Environmental Conservation

THE STATE of ALASKA
GOVERNOR MIKE DUNLEAVY

DIVISION OF AIR QUALITY
Air Compliance Program

P.O. Box 111800
Juneau, Alaska 99811-1800
Main: 907.465.5100
Toll free: 866.241.2805
Fax: 907.465.5129
www.dec.alaska.gov

December 12, 2019

Richard Novcaski, Vice President
3800 Centerpoint Drive, Suite 100
Anchorage, AK 99503

Subject: Rescission of Title V and Minor Permit, Cook Inlet Pipe Line Company, Drift River Terminal and Christy Lee Loading Platform Aggregated Source, Permit and File Nos. Listed Below

Dear Mr. Novacaski:

On December 9, 2019, the Alaska Department of Environmental Conservation (the Department) received Cook Inlet Pipe Line Company's (CIPL) letter dated December 6, 2019, requesting to rescind the Title V (TVP) Permit for the Drift River Terminal and Christy Lee Loading Platform Aggregated Source. The Department took the liberty of rescinding the Minor Permit tied to the Stationary Source, Permit and File Nos. listed in Table A below. This TVP is rescinded as of November 30, 2019.

Source Name	Permit Number	File Number
Drift River Terminal / Christy Lee Platform Aggregated Source	AQ0190TVP03 Rev. 1	2339.16.023
	AQ0190MSS01 (Incorporated in to TVP)	

The Department plans to close out the Drift River Terminal and Christy Lee Loading Platform Aggregated Source's air quality account after our next billing cycle. Our accounts receivable office may contact you to reconcile any outstanding balances.

Please be aware that it is the responsibility of the owner or operator to ensure compliance with State air quality control regulations including any obligation to obtain any air quality control permit. Carefully assess your stationary source's potential to emit to ensure that the source is compliant with State permitting requirements. CIPL did not request an applicability review, the Department's decision to rescind the above TVP is based solely upon CIPL's request to do so.

As allowed under State Regulations 18 AAC 50.225, an owner or operator may request the Department to revoke a TVP approval by explaining the reason for the request. It is the responsibility of the owner or operator to ensure compliance with State regulations including any obligation to obtain any air quality control permit for which the TVP avoided and to comply with any other air quality control requirement.

Please note that upon effective date of this TVP rescission:

1. Limits set by this TVP are no longer effective as of the rescission date. The Drift River Terminal and Christy Lee Loading Platform Aggregated Source may now be subject to permitting thresholds and/or emission standards avoided by the TVP.
2. Keep all records collected under this TVP for five years after the date of collection.
3. If the TVP required annual or periodic reporting, submit a final TVP report covering the period through the date of the rescission, no later than the regularly scheduled due date of the TVP report.
4. All other compliance obligations imposed by this TVP are rescinded.
5. The Department may choose to perform a final TVP compliance evaluation covering the period until the rescission date.

A person who has a private, substantive, legally protected interest under state law that may be adversely affected by this permit action, the owner and operator, or, if a public comment process is required or solicited, a person who participated in the public comment process may request an adjudicatory hearing in accordance with 18 AAC 15.195 - 18 AAC 15.340 or an informal review by the Division Director in accordance with 18 AAC 15.185. Informal review requests must be delivered to the Division Director, PO Box 111800, Juneau, Alaska 99811-1800, within 15 days of receipt of the permit decision by email, facsimile, or mail whichever is earlier.

Adjudicatory hearing requests must be delivered to the Commissioner of the Department of Environmental Conservation, PO Box 111800, Juneau, Alaska 99811-1800, within 30 days of issuance of the permit decision. If a hearing is not requested within 30 days, the right to appeal is waived. More information on how to appeal a Department decision is available at http://www.dec.state.ak.us/commish/ReviewGuidance.htm.

Sincerely,

Jim Plosay, Manager
Air Permits Program

cc: Jason Olds, ADEC/ACP, Juneau
Tom Turner, ADEC/ACP, Anchorage
P. Moses Coss, ADEC/ACP, Fairbanks
Samantha Hoover, ADEC / ACP, Anchorage
Joe Toffolo, ADEC/AS, Anchorage
Julieanna Potter, Hilcorp (jupotter@hilcorp.com)

Eielson Air Force Base
Permit No. AQ0264TVP02
Emissions Fee Estimate (SO2)

ID	Coal Usage (tpy)	Percent of Total	SO2 E.F. (lb/ton)	SO2 E.F. % reduction From EUs 1-4	SO2 Emissions (tons)
2019					
1 through 4	149,281	85%	3.14	0%	234.37
5	11,832	7%	0.27	91%	1.6
6	13,537	8%	0.31	90%	2.1
5 & 6	25,369	15%	0.29	91%	3.7
Total	**174,650**				238.07
2018					
1 through 4	120,945	72%	3.14	0%	189.88
5	18,206	11%	0.59	81%	5.36
6	27,670	17%	1.20	62%	16.6
5 & 6	45,876	28%	0.96	70%	21.96
Total	**166,821**				211.84
2017					
1 through 4	144,712	84%	3.22	0%	232.99
5	23,066	13%	0.49	85%	5.70
6	3,545	2%	0.12	96%	0.21
5 & 6	26,611	16%	0.44	86%	5.91
Total	**171,323**				238.90

2017 - 2019 Totals					
1 through 4	414,938	81%	3.17	0%	657.24
5	53,104	10%	0.48	85%	12.66
6	44,752	9%	0.85	73%	18.91
5 & 6	97,856	19%	0.65	80%	31.57
Total	**512,794**				688.81

Note that 2017 is first year of full operation of EUs 5A and 6A

MATANUSKA ELECTRIC ASSOCIATION
163 East Industrial Way
P.O. Box 2929
Palmer, Alaska 99645

January 22, 2015

Alaska Department of Environmental Conservation
Air Permits Program
ATTN: Assessable Emissions Estimate
410 Willoughby Avenue
Juneau, Alaska 99801-1795

Subject: Eklutna Generation Station – Assessable Emissions Estimate
Fiscal Year 2015 - July 1, 2015 through June 30, 2016
Air Quality Control Minor Permit AQ1086MSS02

To Whom It May Concern,

This assessable emissions estimate for the Eklutna Generation Station is being submitted in accordance with permit condition 3.1 of Minor Air Permit Number AQ1086MSS02 for fiscal year 2016 (July 1, 2015 through June 30, 2016). Based on this assessment, Matanuska Electric Association estimates the assessable emissions fee should be $7,353.75 as shown in the summary table below. The assessable emissions are calculated using the potential to emit of 795 tons per year, in accordance with permit condition 2.1.

Summary of Assessable Emissions Estimate
Air Quality Control Minor Permit Number AQ1086MSS02 Eklutna Generation Station

Pollutant	Projected Annual Assessable Emissions Rate (tpy)
NO_X	187.9
CO	209.32
PM-10	220.71
VOC	20.611
SO_2	156.54
Total Assessable Emissions	795
Emission Fee ($/ton)	$9.25
Estimated Fees	**$7,353.75**

If you have any questions regarding this submittal, please contact me at 907-761-9367 or the air compliance contact, Dani Baldwin at 907-563-2124.

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.

Sincerely,

Gary W. Peers
Eklutna Generation Station Plant Manager

cc: Joe Griffith, MEA
Gary Kuhn, MEA
Tony Zellers, MEA
Traci Bradford, MEA
Dani Baldwin, SLR

From: Nakanishi, Elizabeth D (DEC)
Sent: Tuesday, March 31, 2015 10:29 AM
To: Gesin, Rusty (DEC)
Subject: FW: updated table - fee estimate vs application discrepancy
Attachments: MEA Assessable Emissions__608606.pdf

For your records Rusty… MEA updated their table for the Fees Estimate in the email. The document has
not been fixed.

Elizabeth Nakanishi (DEC)
Environmental Program Technician DEC – AIR PERMTS PROGRAM
(907)269-6953

From: Dani Baldwin [mailto:dbaldwin@slrconsulting.com]
Sent: Tuesday, March 31, 2015 10:14 AM
To: Nakanishi, Elizabeth D (DEC)
Cc: Gary W. Peers; Traci R. Bradford; Agyei, Kwame (DEC); Dunn, Patrick E (DEC)
Subject: updated table - fee estimate vs application discrepancy

Ms. Nakanishi,

Per our phone conversation, here is the corrected table for MEA's assessable fee estimate
submittal. The table in the attached letter had the correct values but VOC should be 156.54 and SO2
should be 20.611, as adjusted below in red.

Summary of Assessable Emissions Estimate

Pollutant
Projected Annual Assessable
Emissions Rate (tpy)
NOX
187.9
CO
209.32
PM-10
220.71
SO2
20.611
VOC
156.54
Total Assessable Emissions
795
Emission Fee ($/ton)
$9.25
Estimated Fees
$7,353.75

Regards,
Dani

Dani Baldwin
Associate Engineer
SLR International Corporation

Dire
ct:
907-
563-
2124
Offic
e:
907-
222-
1112
Fax:
907-
222-
1113
Ema
il:
dbal
dwin
@slr
cons
ultin
g.co
m
2700 Gambell Street, Suite 200, Anchorage, AK, 99503, United States

www.slrconsulting.com

From: Dani Baldwin
Sent: March 30, 2015 9:08 AM
To: 'elizabeth.nakanishi@alaska.gov'
Cc: 'Gary W. Peers'; 'Traci R. Bradford'; 'Agyei, Kwame (DEC)'; Dunn, Patrick E (DEC)

Subject: RE: fee estimate vs application discrepancy

Ms. Nakanishi,

On behalf of MEA, I wanted to respond to your email below. Currently, I prepare the assessable fee
estimates for MEA. The fee estimate matches Air Quality Control Permit AQ1086MSS02, Condition 2.1
and identically matches the Technical Analysis Report (TAR) Table A-1. Please find the attached TAR. I
believe the difference in the minor permit application calculations (after modification) and the TAR
comes down to the significant figures used to sum emissions in Table A-1.

Also in your email below, you referenced the "before modification" emissions calculations in the permit
application (MSS01) and the basis for the air permit application revision (MSS02) is using "after
modification" emissions in the attached Table B-1. The after modification emissions are very close to
the values found in Table A-1 of the TAR.

Please let me know if you have any more questions regarding the assessable fee estimate submittal for
MEA.

Regards,
Dani
907-563-2124

Begin forwarded message:
From: "Nakanishi, Elizabeth D (DEC)" <elizabeth.nakanishi@alaska.gov>
Date: March 27, 2015 at 11:43:30 AM PDT
To: "gary.peers@mea.coop" <gary.peers@mea.coop>
Cc: "Agyei, Kwame (DEC)" <kwame.agyei@alaska.gov>, "Dunn, Patrick E (DEC)" <patrick.dunn@alaska.gov>
Subject: fee estimate vs application discrepancy
Mr Peers,

I noticed that your recent fees estimate does not match the values reported on your

application for the Eklutna Generation Station.

On the application for AQ1086MSS02 table B-1, Matanuska Electric Association, Inc reported:
VOC 155.4 TPY
SO2 19.2 tpy

Submitted January 22, 2015, this recent assessable emissions fees estimate

reports:
VOC 20.611
SO2 156.54

Please review your records and determine the correct values for VOC and SO2 so that

we can correct our records for your source.

Thank you for your time,
Elizabeth

Elizabeth Nakanishi (DEC)
Environmental Program Technician DEC – AIR PERMTS PROGRAM
(907)269-6953

CAMBX1S

MATANUSKA ELECTRIC ASSOCIATION

March 23, 2017

CERTIFIED MAIL: 7015 1660 0000 8907 5818
Return Receipt Requested

Alaska Department of Environmental Conservation
Air Permits Program
ATTN: Assessable Emissions Estimate
410 Willoughby Avenue
Juneau, AK 99801-1795

RECEIVED
MAR 28 2017
ADEC AQ

Subject: FY 2018 Assessable Emissions Estimate
Matanuska Electric Association – Eklutna Generation Station
Minor Air Quality Control Permit Number AQ1086TVP01

To Whom It May Concern,

Matanuska Electric Association (MEA) is submitting the enclosed fiscal year (FY) 2018 assessable emissions estimate for the Eklutna Generation Station in accordance with Condition 40.1 of Air Quality Operating Permit Number AQ1086TVP01 and Condition 3.1 of Minor Air Quality Permit Number AQ1086MSS03 for FY 2018. Based on this assessment, MEA estimates the assessable emissions fee at $5,277.83 as shown in the attached summary table.

If you have any questions regarding this submittal, please contact Traci Bradford by phone at 907-761-9374 or by email at traci.bradford@mea.coop.

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.

Sincerely,

Michael Mann
Plant Manager
Eklutna Generation Station

Enclosure: Assessable Emissions Estimate

cc: Gary Kuhn, MEA
Tony Izzo, MEA
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Table A-1. Matanuska Electric Association - Eklutna Generation Station
FY 2018 Assessable Emissions Estimate

Pollutant	Assessable Potential to Emit[1]	CY 2016 Actual Emissions[2, 3]	Assessable Emissions[4]
Oxides of Nitrogen (NO_X)	188 tpy	61.1 tpy	61.1 tons
Carbon Monoxide (CO)	209 tpy	11.4 tpy	11.4 tons
Particulate Matter less than 10 micrometers in diameter (PM_{10})	221 tpy	15.5 tpy	15.5 tons
Volatile Organic Compounds (VOC)	157 tpy	21.3 tpy	21.3 tons
Oxides of Sulfur (SO_2)	21 tpy	13.6 tpy	13.6 tons
Total	796 tpy	122.9 tpy	122.9 tons

Assessable Emissions Fee[5] $ 5,277.83

Notes:

1. From Condition 40.1 of AQ1086TVP01 and Table C of the Statement of Basis for AQ1086TVP01.
2. Regulated air pollutant calculations are based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying emission tables.
3. Table A-2 provides a summary of 2016 actual operating hours by fuel type.
4. Fee not calculated for pollutant totals less than 10 tons.
5. Assessable emission fee is $42.95 per ton per 18 AAC 50.410(b)(1).

Table A-2. Matanuska Electric Association - Eklutna Generation Station
Emission Unit Inventory

Emission Unit			Fuel Type	Installation Date	CY 2016 Actual Operation	Maximum Capacity
ID	Description	Make/Model				
1	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	4,789 hr/yr	17.1 MW
2	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	7,139 hr/yr	17.1 MW
3	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	5,857 hr/yr	17.1 MW
4	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	6,519 hr/yr	17.1 MW
5	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	6,339 hr/yr	17.1 MW
6	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	6,765 hr/yr	17.1 MW
7	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	7,217 hr/yr	17.1 MW
8	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	4,309 hr/yr	17.1 MW
9	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	4,383 hr/yr	17.1 MW
10	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	4,924 hr/yr	17.1 MW
1-10 (combined)	Generator Engine	Wartsila 18V50DF	Diesel	N/A	294 hr/yr	17.1 MW (each)
11	Firewater Pump Engine	John Deere JU6H-UFADN0	Diesel	October 2014	26 hr/yr	197 hp
12	Black Start Generator Engine	Cummins 1000DQFAD	Diesel	April 2015	17 hr/yr	1,490 hp
18	Black Start Generator Engine	Cummins 1000DQFAD	Diesel	April 2015		1,490 hp
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	NG	October 2014	3,382 hr/yr	15.75 MMBtu/hr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	NG	October 2014	763 hr/yr	15.75 MMBtu/hr
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	Diesel	October 2014	0.4 hr/yr	15.75 MMBtu/hr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	Diesel	October 2014		15.75 MMBtu/hr
15	Diesel Storage Tank	Rockford Corporation	Diesel	November 2014	8,760 hr/yr	436,842 gallons
16	Diesel Storage Tank	Rockford Corporation	Diesel	November 2014	8,760 hr/yr	436,842 gallons
17	Natural Gas Fuel Heater	ETI	NG	TBD	0 hr/yr	7.0 MMBtu/hr

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Table A-3. Matanuska Electric Association - Eklutna Generation Station
FY 2018 NO_x Emissions Calculations

Emission Unit			Fuel	Factor	NO_x Emission	CY 2016 Actual	CY 2016 Actual NO_x
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	1.08 lb/hr	4,789 hr/yr	2.6 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/26/16	1.60 lb/hr	7,139 hr/yr	5.7 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	1.89 lb/hr	5,857 hr/yr	5.5 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	2.36 lb/hr	6,519 hr/yr	7.7 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/28/16	2.65 lb/hr	6,339 hr/yr	8.4 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/28/16	2.73 lb/hr	6,765 hr/yr	9.2 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/29/16	1.93 lb/hr	7,217 hr/yr	7.0 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/29/16	0.93 lb/hr	4,309 hr/yr	2.0 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/23/16	1.88 lb/hr	4,383 hr/yr	4.1 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/30/16	1.75 lb/hr	4,924 hr/yr	4.3 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	19.95 lb/hr	294 hr/yr	2.9 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	2.7 g/hp-hr	26 hr/yr	0.0 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	5.20 g/hp-hr	17 hr/yr	0.1 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	5.20 g/hp-hr		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	1.30 lb/hr	3,382 hr/yr	2.2 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	1.30 lb/hr	763 hr/yr	0.5 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	2.18 lb/hr	0.4 hr/yr	0.0 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	2.18 lb/hr		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	436,842 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	Manufacturer Data	0.78 lb/hr	0 hr/yr	0.0 tpy
						Total CY 2016 Actual NO_x Emissions	61.1 tpy

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Table A-4. Matanuska Electric Association - Eklutna Generation Station
FY 2018 CO Emissions Calculations

Emission Unit			Fuel	Factor	CO Emission	CY 2016 Actual	CY 2016 Actual CO
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	0.38 lb/hr	4,789 hr/yr	0.9 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/26/16	0.42 lb/hr	7,139 hr/yr	1.5 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	0.18 lb/hr	5,857 hr/yr	0.5 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	0.28 lb/hr	6,519 hr/yr	0.9 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/28/16	0.27 lb/hr	6,339 hr/yr	0.8 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/28/16	0.32 lb/hr	6,765 hr/yr	1.1 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/29/16	0.29 lb/hr	7,217 hr/yr	1.0 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/29/16	0.35 lb/hr	4,309 hr/yr	0.8 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/23/16	0.69 lb/hr	4,383 hr/yr	1.5 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/30/16	0.17 lb/hr	4,924 hr/yr	0.4 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	6.78 lb/hr	294 hr/yr	1.0 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.9 g/hp-hr	26 hr/yr	0.0 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.66 g/hp-hr	17 hr/yr	0.0 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.66 g/hp-hr		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.58 lb/hr	3,382 hr/yr	1.0 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.58 lb/hr	763 hr/yr	0.2 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.56 lb/hr	0.4 hr/yr	0.0 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.56 lb/hr		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	436,842 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	Manufacturer Data	0.78 lb/hr	0 hr/yr	0.00 tpy
						Total CY 2016 Actual CO Emissions	**11.4 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Table A-5. Matanuska Electric Association - Eklutna Generation Station
FY 2018 PM_{10} Emissions Calculations

Emission Unit			Fuel	Factor	PM_{10} Emission	CY 2016 Actual	CY 2016 Actual PM_{10}
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	EU ID 10 Source Test 2/3/15	0.48 lb/hr	4,789 hr/yr	1.1 tpy
2	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	7,139 hr/yr	1.7 tpy
3	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,857 hr/yr	1.4 tpy
4	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	6,519 hr/yr	1.6 tpy
5	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	6,339 hr/yr	1.5 tpy
6	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	6,765 hr/yr	1.6 tpy
7	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	7,217 hr/yr	1.7 tpy
8	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	4,309 hr/yr	1.0 tpy
9	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	4,383 hr/yr	1.1 tpy
10	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	4,924 hr/yr	1.2 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	10.92 lb/hr	294 hr/yr	1.6 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.1 g/hp-hr	26 hr/yr	0.0 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.19 g/hp-hr	17 hr/yr	0.0 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.19 g/hp-hr		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.10 lb/hr	3,382 hr/yr	0.2 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.10 lb/hr	763 hr/yr	0.0 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.32 lb/hr	0.4 hr/yr	0.0 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.32 lb/hr		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	436,842 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	Manufacturer Data	0.008 lb/MMBtu	0 hr/yr	0.0 tpy
						Total CY 2016 Actual PM_{10} Emissions	15.5 tpy

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Table A-6. Matanuska Electric Association - Eklutna Generation Station
FY 2018 VOC Emissions Calculations

Emission Unit			Fuel	Factor	VOC Emission	CY 2016 Actual	CY 2016 Actual VOC
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	0.81 lb/hr	4,789 hr/yr	1.9 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/26/16	1.11 lb/hr	7,139 hr/yr	4.0 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	0.56 lb/hr	5,857 hr/yr	1.6 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/27/16	0.99 lb/hr	6,519 hr/yr	3.2 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/28/16	0.79 lb/hr	6,339 hr/yr	2.5 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/28/16	0.53 lb/hr	6,765 hr/yr	1.8 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/29/16	0.47 lb/hr	7,217 hr/yr	1.7 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/29/16	0.44 lb/hr	4,309 hr/yr	1.0 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/23/16	0.19 lb/hr	4,383 hr/yr	0.4 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 1/30/16	0.92 lb/hr	4,924 hr/yr	2.3 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	7.91 lb/hr	294 hr/yr	1.2 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.1 g/hp-hr	26 hr/yr	0.00 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.12 g/hp-hr	17 hr/yr	0.0 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.12 g/hp-hr		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.06 lb/hr	3,382 hr/yr	0.1 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.06 lb/hr	763 hr/yr	0.0 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.06 lb/hr	0.4 hr/yr	0.00 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.06 lb/hr		
15	Diesel Storage Tank	436,842 gallons	Diesel	TANKS 4.09d	Not Applicable	8,760 hr/yr	0.01 tpy
16	Diesel Storage Tank	436,842 gallons	Diesel	TANKS 4.09d		8,760 hr/yr	0.01 tpy
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	Manufacturer Data	0.48 lb/hr	0 hr/yr	0.0 tpy
Total CY 2016 Actual VOC Emissions							21.3 tpy

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Table A-7. Matanuska Electric Association - Eklutna Generation Station
FY 2018 SO_2 Emissions Calculations

Emission Unit			Fuel	Factor	SO_2 Emission	CY 2016 Actual	CY 2016 Actual SO_2
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Natural Gas	20 ppmv H_2S	4,789 hr/yr	1.1 tpy
2	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	7,139 hr/yr	1.6 tpy
3	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,857 hr/yr	1.4 tpy
4	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	6,519 hr/yr	1.5 tpy
5	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	6,339 hr/yr	1.5 tpy
6	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	6,765 hr/yr	1.6 tpy
7	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	7,217 hr/yr	1.7 tpy
8	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	4,309 hr/yr	1.0 tpy
9	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	4,383 hr/yr	1.0 tpy
10	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	4,924 hr/yr	1.1 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	ULSD	15 ppmw S	294 hr/yr	0.10 tpy
11	Firewater Pump Engine	197 hp	Diesel	ULSD	15 ppmw S	26 hr/yr	0.000 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	ULSD	15 ppmw S	17 hr/yr	0.00 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	ULSD	15 ppmw S		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	NG	20 ppmv H_2S	3,382 hr/yr	0.1 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	NG	20 ppmv H_2S	763 hr/yr	0.0 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	ULSD	15 ppmw S	0.4 hr/yr	0.00 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	ULSD	15 ppmw S		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	436,842 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	NG	20 ppmv H_2S	0 hr/yr	0.0 tpy
						Total CY 2016 Actual SO_2 Emissions	13.6 tpy

Notes:
1. NG is natural gas. ULSD is ultra-low sulfur diesel.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel. This is included in the EU ID 1-10 combined diesel use emissions.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.
4. Conversions and Vendor Data:

EU IDs 1-10 natural gas (with 1% diesel) heat rate:	8,153 kJ/kW-hr (NG)	EU IDs 13 and 14 fuel consumption rate:	15,752 scf/hr
EU IDs 1-10 natural gas (with 1% diesel) fuel consumption	2 g/kW-hr (diesel)	EU IDs 13 and 14 fuel consumption rate:	110.31 gal/hr
EU IDs 1-10 diesel fuel consumption rate:	204 g/kW-hr	Natural gas heat content:	1,020 Btu/scf
EU ID 11 fuel consumption rate:	10.3 gal/hr	Standard Molar Volume:	359 scf/lb-mole
EU IDs 12 and 18 fuel consumption rate:	72.2 gal/hr	Diesel Heat Content:	138,000 Btu/gallon
EU ID 17 fuel consumption rate:	8,444 scf/hr	Diesel Density:	6.9 lb/gallon

Table A-8. Matanuska Electric Association - Eklutna Generation Station
FY 2018 Emissions Calculations - Wartsila 18V50DF Manufacturer Data

Engine Operation[1,2]							
Percent Load	100	75	50		100	75	50
Engine Output, kW	17,076	12,974	8,494		17,076	12,974	8,494
Inlet Temperature, °C	15.6	15.6	15.6		26.7	26.7	26.7
Natural Gas[3]							
Natural Gas Fuel Consumption, kJ/kW-hr	7,258	7,562	8,153		7,258	7,562	8,153
Diesel Fuel Consumption, g/kW-hr	1.0	1.5	2.4		1.0	1.5	2.4
Flue Gas Temperature, °C ±15°C	399	435	443		397	433	441
Flue Gas Flow, kg/s ±5%	27.6	21.3	15.9		27.6	21.3	15.9
Flue Gas Flow, Nm^3/s (Dry)	19.7	15.2	11.3		19.6	15.1	11.3
Flue Gas Flow, Nm^3/s (Wet)[4]	21.9	16.9	12.6		21.8	16.8	12.6
Flue Gas Flow, m^3/s (Actual)	51.0	41.4	31.1		50.6	41.0	31.1
Flue Gas Velocity, m/s	25.7	20.9	15.8		24.8	20.9	15.8
NO_X, ppmvd @ 15% O_2	6	9	9		6	9	9
NO_X, g/kW-hr	0.08	0.12	0.13		0.08	0.12	0.13
NO_X, lb/hr	3.01	3.43	2.43		3.01	3.43	2.43
CO, ppmvd @ 15% O_2	15	15	15		15	15	15
CO, g/kW-hr	0.12	0.12	0.13		0.12	0.12	0.13
CO, lb/hr	4.52	3.43	2.43		4.52	3.43	2.43
PM_{10}, mg/Nm^3 @ 15% O_2 (Dry)	20	25	30		20	25	30
PM_{10}, g/kW-hr	0.13	0.16	0.21		0.13	0.16	0.21
PM_{10}, lb/hr	4.89	4.58			4.89	4.58	3.93
VOC, ppmvd @ 15% O_2	20	25	25		20	25	25
VOC, g/kW-hr	0.09	0.12	0.13		0.09	0.12	0.13
VOC, lb/hr	3.39	3.43	2.43		3.39	3.43	2.43
CH_2O, ppmvd @ 15% O_2	0.70	NA	NA		0.70	NA	NA
CH_2O, lb/hr[6]	0.23	NA	NA		0.23	NA	NA
Diesel							
Fuel Consumption, g/kW-hr	189	192	204		189	192	204
Flue Gas Temperature, °C ±15°C	355	355	389		368	368	402
Flue Gas Flow, kg/s ±5%	34.5	27.4	18.9		33.3	26.4	18.3
Flue Gas Flow, Nm^3/s (Dry)	25.1	20	13.8		24.1	19.2	13.3
Flue Gas Flow, Nm^3/s (Wet)[5]	26.4	21.1	14.5		25.4	20.2	14.0
Flue Gas Flow, m^3/s (Actual)	57.5	45.8	33.3		56.3	44.9	32.7
Flue Gas Velocity, m/s	30.1	23.9	17.4		29.6	23.5	17.1
NO_X, ppmvd @ 15% O_2	35	40	40		35	40	40
NO_X, g/kW-hr	0.53	0.61	0.64		0.53	0.61	0.64
NO_X, lb/hr	19.95	17.45	11.98		19.95	17.45	11.98
CO, ppmvd @ 15% O_2	20	20	20		20	20	20
CO, g/kW-hr	0.18	0.19	0.19		0.18	0.19	0.19
CO, lb/hr	6.78	5.43	3.56		6.78	5.43	3.56
PM_{10}, mg/Nm^3 @ 15% O_2 (Dry)	40	50	60		40	50	60
PM_{10}, g/kW-hr	0.29	0.37	0.46		0.29	0.37	0.46
PM_{10}, lb/hr	10.92	10.58	8.61		10.92	10.58	8.61
VOC, ppmvd @ 15% O_2	40	40	40		40	40	40
VOC, g/kW-hr	0.21	0.21	0.22		0.21	0.21	0.22
VOC, lb/hr	7.91	6.01	4.12		7.91	6.01	4.12
CH_2O, ppmvd @ 15% O_2	0.70	NA	NA		0.70	NA	NA
CH_2O, lb/hr[7]	0.28	NA	NA		0.28	NA	NA

Table A-8. Matanuska Electric Association - Eklutna Generation Station
FY 2018 Emissions Calculations - Wartsila 18V50DF Manufacturer Data

Notes:

1. Values at 25 percent load are not provided, because this load is normally below manufacturer guaranteed stable operation.
2. Emission rates represent source test data measured after Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CATOX) emission control systems. SCR control efficiency estimated at 93 to 94 percent. CATOX control efficiency estimated at 93 to 94 percent for carbon monoxide and 70 percent for volatile organic compounds.
3. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
4. Normal flue gas flow for natural gas combustion assumes 10 percent moisture content. Actual pressure is conservatively estimated as standard pressure.
5. Normal flue gas flow for diesel combustion assumes 5 percent moisture content. Actual pressure is conservatively estimated as standard pressure.
6. Based on F_d factor of 8,710 for natural gas (40 CFR 60, Appendix A, Method 19).
7. Based on F_d factor of 9,190 for diesel (40 CFR 60, Appendix A, Method 19).

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UNITED STATES POSTAGE
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MAILED FROM ZIP CODE 99645

UNITED STATES POSTAL SERVICE
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U.S. POSTAGE
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99645
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AMOUNT
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MEA
MATANUSKA ELECTRIC ASSOCIATION, INC.
P.O. Box 2929 • Palmer, Alaska 99645
907.761.9300

Alaska Department of Environmental Conservation
Air Permits Program
ATTN: Assessable Emissions Estimate
410 Willoughby Avenue
Juneau, AK 99801-1795

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY OPERATING PERMIT

Permit No. AQ1086TVP01

Issue Date: January 27, 2017
Expiration Date: January 27, 2022

The Alaska Department of Environmental Conservation, under the authority of AS 46.14 and 18 AAC 50, issues an operating permit to the Permittee, **Matanuska Electric Association, Inc.**, for the operation of the **Eklutna Generation Station**.

This permit satisfies the obligation of the owner and operator to obtain an operating permit as set out in AS 46.14.130(b).

As set out in AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this operating permit.

Citations listed herein are contained within the effective version of 18 AAC 50 at permit issuance. All federal regulation citations are from those sections adopted by reference in this version of regulation in 18 AAC 50.040 unless otherwise specified.

This permit incorporates all applicable terms and conditions of Air Quality Minor Permit No. AQ1086MSS03 issued November 6, 2015.

This Operating Permit becomes effective February 26, 2017.

for

John F. Kuterbach, Manager
Air Permits Program

Table of Contents

Abbreviations and Acronyms

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AS	Alaska Statutes
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
Bhp	brake horsepower
CATOX	catalytic oxidation
CAA	Clean Air Act
The Act	Clean Air Act
C.F.R.	Code of Federal Regulations
CH_2O	formaldehyde
CO	carbon monoxide
Department	Alaska Department of Environmental Conservation
dscf	dry standard cubic foot
EPA	US Environmental Protection Agency
EU	emission unit
gr./dscf	grain per dry standard cubic foot (1 pound = 7000 grains)
GPH	gallons per hour
HAP	hazardous air pollutants [HAP as defined in AS 46.14.990]
hp	horsepower
H_2S	hydrogen sulfide
ID	emission unit identification number
kPa	kilopascals
kW	kilowatt
LAER	Lowest Achievable Emission Rate
MACT	Maximum Achievable Control Technology [MACT 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
MW	Megawatt
NESHAP	Federal National Emission Standards for Hazardous Air Pollutants [NESHAP as contained in 40 C.F.R. 61 and 63]
NFPA	National Fire Protection Association
NG	natural gas
NO_X	nitrogen oxides
NO_2	nitrogen dioxide
NSPS	Federal New Source Performance Standards [NSPS as contained in 40 C.F.R. 60]
O & M	operation and maintenance
O_2	Oxygen
ORL	owner requested limit
PAL	Plant wide Applicability Limitation
PM-10	particulate matter less than or equal to a nominal ten 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
SCR	selective catalytic reduction
SIC.	Standard Industrial Classification
SO_2	sulfur dioxide
tpy	tons per year
ULSD	Ultra Low Sulfur Diesel
VOC	volatile organic compound [VOC as defined in 40 C.F.R. 51.100(s)]
VOL	volatile organic liquid [VOL as defined in 40 C.F.R. 60.111b, Subpart Kb]
vol%	volume percent
wt%	weight percent

Section 1. Stationary Source Information

Identification

Permittee:		**Matanuska Electric Association, Inc.** P.O. Box 2929 Palmer, AK 99645
Stationary Source Name:		**Eklutna Generation Station**
Location:		61º 27´ 34.5” North; 149º 20´ 33.9” West
Physical Address:		28705 Dena'ina Elders Road Chugiak, AK 99567
Owner/Operator:		**Matanuska Electric Association, Inc.** P.O. Box 2929 Palmer, AK 99645
Permittee's Responsible Official and Designated Agent:		Michael Mann, Eklutna Generation Station Plant Manager P.O. Box 2929 Palmer, AK 99645
Stationary Source and Building Contact:		Traci Bradford, Environmental Engineer P.O. Box 2929 Palmer, AK 99645 907-761-9374 traci.bradford@mea.coop
Fee Contact:		Traci Bradford, Environmental Engineer P.O. Box 2929 Palmer, AK 99645 907-761-9374
Permit Contact:		Traci Bradford, Environmental Engineer P.O. Box 2929 Palmer, AK 99645 907-761-9374 traci.bradford@mea.coop
Process Description	SIC Code:	4911 – Electric services
	NAICS Code:	221112 – Fossil fuel electric power generation

[18 AAC 50.040(j)(3) & 50.326(a)]
[40 C.F.R. 71.5(c)(1) & (2)]

Section 2. Emission Unit Inventory and Description

Emission units listed in Table A have specific monitoring, recordkeeping, or reporting conditions in this permit. Except as noted elsewhere in the permit, emission unit descriptions and ratings are given for identification purposes only.

Table A - Emission Unit Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Fuel	Construction Date
1	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
2	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
3	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
4	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
5	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
6	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
7	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
8	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
9	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
10	Generator Engine	Wärtsilä 18V50DF	17.1 MW	Natural Gas /ULSD	March 2012
11	Fire Pump Engine	John Deere JU6H-UFADN0	197 hp	ULSD	June 2012
12	Black Start Generator Engine	Cummins 1000DQFAD	1,490 hp	ULSD	June 2013
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	Natural Gas /ULSD	June 2013
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	Natural Gas /ULSD	June 2013
15	Diesel Storage Tank	Rockford 071301	436,842 gal	ULSD	March 2013
16	Diesel Storage Tank	Rockford 071301	436,842 gal	ULSD	March 2013
17	NG Fuel Heater	ETI	7.0 MMBtu/hr	Natural Gas	To be determined
18	Black Start Generator Engine	Cummins 1000DQFAD	1,490 hp	ULSD	June 2013

Note:

EU ID 11 has actual emissions below the significant emissions thresholds in 18 AAC 50.326(e). However, it is included in this permit because it is subject to the requirements of Minor Permit No. AQ1086MSS03 and 40 C.F.R. 60 Subpart IIII and therefore cannot be classified as insignificant per 18 AAC 50.326(d)(1)(A) and (C).

[18 AAC 50.326(a)]
[40 C.F.R. 71.5(c)(3)]

Section 3. State Requirements

Visible Emissions Standard

1. **Industrial Process and Fuel-Burning Equipment Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from EU IDs 1 through 14, 17, and 18 listed in Table A to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

[18 AAC 50.040(j), 50.055(a)(1), &50.326(j)]
[40 C.F.R. 71.6(a)(1)]

1.1. For EU IDs 1 through 10, 13, and 14, use natural gas as primary fuel. Monitoring for these emission units shall consist of a statement in each operating report under Condition 63 indicating whether each of these EUs fired natural gas as the primary fuel during the period covered by the report. If exclusive operation on ULSD occurred during the period covered by the report, the Permittee shall monitor, record, and report according to Condition 9.

1.2. For EU ID 17, burn only natural gas as fuel. Monitoring for this emission unit shall consist of a statement in each operating report under Condition 63 indicating whether the emission unit fired only natural gas during the period covered by the report. Report under Condition 62 if any fuel other than natural gas is burned.

1.3. For EU ID 11, as long as the emission unit does not exceed the operational hour limit in Condition 13, monitoring shall consist of an annual compliance certification under Condition 64 with the visible emission standard. Otherwise, monitor, record and report visible emissions in accordance with Conditions 2 through 4 for the remainder of the permit term.

1.4. For EU IDs 12 and 18, monitor, record, and report in accordance with Conditions 2 through 4.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)]

Visible Emissions Monitoring, Recordkeeping and Reporting

Liquid Fuel-Fired Emission Units

2. **Visible Emissions Monitoring.** When required by any of Condition 1.3 or 1.4, or in the event of replacement during the permit term, the Permittee shall observe the exhaust of EU IDs 11, 12, and 18 for visible emissions using either the Method 9 Plan under Condition 2.1 or the Smoke/No-Smoke Plan under Condition 2.2. The Permittee may change visible-emissions plans for an emission unit at any time unless prohibited from doing so by Condition 2.3. The Permittee may, for each unit, elect to continue the visible emissions monitoring schedule in effect from a previous permit, if applicable.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

2.1. **Method 9 Plan.** For all 18-minute observations in this plan, observe exhaust, following 40 C.F.R. 60, Appendix A-4, Method 9, adopted by reference in 18 AAC 50.040(a), for 18 minutes to obtain 72 consecutive 15-second opacity observations.

a. First Method 9 Observation. Except as provided in Condition 2.3.c(ii), for EU IDs 11, 12 and 18, observe exhaust for 18 minutes within six months after the issue date of this permit or during the next scheduled operation following issuance of this permit, whichever is later. For any unit, observe exhaust for 18 minutes within 14 calendar days after changing from the Smoke/No-Smoke Plan of Condition 2.2.

(i) For any unit replaced during the term of this permit, observe exhaust for 18 minutes within 30 days of startup.

b. Monthly Method 9 Observations. After the first Method 9 observation, perform 18-minute observations at least once in each calendar month that an emission unit operates.

c. Semiannual Method 9 Observations. After observing emissions for three consecutive operating months under Condition 2.1.b, unless a six-minute average is greater than 15 percent and one or more observations are greater than 20 percent, perform 18-minute observations:

(i) Within six months after the preceding observation, or

(ii) For an emission unit with intermittent operations, during the next scheduled operation immediately following six months after the preceding observation.

d. Annual Method 9 Observations. After at least two semiannual 18-minute observations, unless a six-minute average is greater than 15 percent and one or more individual observations are greater than 20 percent, perform 18-minute observations:

(i) Within twelve months after the preceding observation; or

(ii) For an emission unit with intermittent operations, during the next scheduled operation immediately following twelve months after the preceding observation

e. Increased Method 9 Frequency. If a six-minute average opacity is observed during the most recent set of observations to be greater than 15 percent and one or more observations are greater than 20 percent, then increase or maintain the 18-minute observation frequency for that emission unit to at least monthly intervals as described in Condition 2.1.b, until the criteria in Condition 2.1.c for semiannual monitoring are met.

2.2. **Smoke/No Smoke Plan.** Observe the exhaust for the presence or absence of visible emissions, excluding condensed water vapor.

a. Initial Monitoring Frequency. Observe the exhaust during each calendar day that an emission unit operates.

b. Reduced Monitoring Frequency. After the emission unit has been observed on 30 consecutive operating days, if the emission unit operated without visible smoke in the exhaust for those 30 days, then observe emissions at least once in every calendar month that an emission unit operates.

c. Smoke Observed. If smoke is observed, either begin the Method 9 Plan of Condition 2.1 or perform the corrective action required under Condition 2.3

2.3. **Corrective Actions Based on Smoke/No Smoke Observations**. If visible emissions are present in the exhaust during an observation performed under the Smoke/No Smoke Plan of Condition 2.2, then the Permittee shall either follow the Method 9 plan of Condition 2.1 or

a. initiate actions to eliminate smoke from the emission unit within 24 hours of the observation;

b. keep a written record of the starting date, the completion date, and a description of the actions taken to reduce smoke; and

c. after completing the actions required under Condition 2.3.a,

(i) take smoke/no smoke observations in accordance with Condition 2.2.

(A) at least once per day for the next seven operating days and until the initial 30 day observation period is completed; and

(B) continue as described in Condition 2.2.b; or

(ii) if the actions taken under Condition 2.3.a do not eliminate the smoke, or if subsequent smoke is observed under the schedule of Condition 2.3.c(i)(A), then observe the exhaust using the Method 9 Plan unless the Department gives written approval to resume observations under the Smoke/No Smoke Plan; after observing smoke and making observations under the Method 9 Plan, the Permittee may at any time take corrective action that eliminates smoke and restart the Smoke/No Smoke Plan under Condition 2.2.a.

3. Visible Emissions Recordkeeping. When required by any of Condition 1.3 or 1.4, or in the event of replacement of any of EU IDs 11, 12, and 18 during the permit term, the Permittee shall keep records as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(ii)]

3.1. If using the Method 9 Plan of Condition 2.1,

a. the observer shall record

(i) the name of the stationary source, emission unit and location, emission unit type, observer's name and affiliation, and the date on the Visible Emission Observation Form in Section 11;

(ii) the time, estimated distance to the emissions location, sun location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), plume background, and operating rate (load or fuel consumption rate or best estimate if unknown) on the sheet at the time opacity observations are initiated and completed;

(iii) the presence or absence of an attached or detached plume and the approximate distance from the emissions outlet to the point in the plume at which the observations are made;

(iv) opacity observations to the nearest five percent at 15-second intervals on the Visible Emission Observation Form in Section 11, and

(v) the minimum number of observations required by the permit; each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.

b. To determine the six-minute average opacity, divide the observations recorded on the record sheet into sets of 24 consecutive observations; sets need not be consecutive in time and in no case shall two sets overlap; for each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24; record the average opacity on the sheet.

c. Calculate and record the highest 6-minute and 18-consecutive-minute averages observed.

3.2. If using the Smoke/No Smoke Plan of Condition 2.2, record the following information in a written log for each observation and submit copies of the recorded information upon request of the Department:

a. the date and time of the observation;

b. from Table A, the ID of the emission unit observed;

c. whether visible emissions are present or absent in the exhaust;

d. a description of the background to the exhaust during the observation;

e. if the emission unit starts operation on the day of the observation, the startup time of the emission unit;

f. name and title of the person making the observation; and

g. operating rate (load or fuel consumption rate).

4. Visible Emissions Reporting. When required by any of Condition 1.3 or 1.4, or in the event of replacement of any of EU IDs 11, 12, and 18 during the permit term, the Permittee shall report visible emissions as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

4.1. Include in each operating report required under Condition 63:

a. which visible-emissions plan of Condition 2 was used for each emission unit; if more than one plan was used, give the time periods covered by each plan;

b. for each emission unit under the Method 9 Plan,

(i) copies of the observation results (i.e. opacity observations) for each emission unit that used the Method 9 Plan, except for the observations the Permittee has already supplied to the Department; and

(ii) a summary to include:

(A) number of days observations were made;

(B) highest six-minute average observed; and

(C) dates when one or more observed six-minute averages were greater than 20 percent;

c. for each emission unit under the Smoke/No Smoke Plan, the number of days that smoke/no smoke observations were made and which days, if any, that smoke was observed; and

d. a summary of any monitoring or recordkeeping required under Conditions 2 and 3 that was not done;

4.2. Report under Condition 62:

a. the results of Method 9 observations that exceed an average of 20 percent opacity for any six-minute period; and

b. if any monitoring under Condition 2 was not performed when required, report within three days of the date the monitoring was required.

Particulate Matter Emissions Standard

5. Industrial Process and Fuel-Burning Equipment Particulate Matter. The Permittee shall not cause or allow particulate matter (PM) emitted from EU IDs 1 through 14, 17, and 18 listed in Table A to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

[18 AAC 50.040(j), 50.055(b)(1), & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

5.1. For EU IDs 1 through 10, 13, and 14, use natural gas as primary fuel. Monitoring for these emission units shall consist of a statement in each operating report under Condition 63 indicating whether each of these EUs fired natural gas as the primary fuel during the period covered by the report. If exclusive operation on ULSD occurred during the period covered by the report, the Permittee shall monitor, record, and report according to Condition 9.

5.2. For EU ID 17, burn only natural gas as fuel. Monitoring for this emission unit shall consist of a statement in each operating report under Condition 63 indication whether this emission unit fired only natural gas during the period covered by the report. Report under Condition 62 if any fuel other than natural gas is burned.

5.3. For EU ID 11, as long as the emission unit does not exceed the operational hour limit in Condition 13, monitoring shall consist of an annual compliance certification under Condition 64 with the particulate matter standard. Otherwise, monitor, record and report particulate matter emissions in accordance with Conditions 6 through 8 for the remainder of the permit term.

5.4. For EU IDs 12 and 18, monitor, record, and report in accordance with Conditions 6 through 8.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)]

Particulate Matter Monitoring, Recordkeeping and Reporting

Liquid Fuel-Fired Engines

6. Particulate Matter Monitoring for Diesel Engines. When required by any of Condition 5.3 or 5.4, the Permittee shall conduct source tests on diesel engines, EU IDs 11, 12 and 18 to determine the concentration of particulate matter (PM) in the exhaust of an emission unit as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(i)]

6.1. Except as allowed under Condition 6.4, within six months of exceeding the criteria of Condition 6.2.a or 6.2.b, either

a. conduct a PM source test according to requirements set out in Section 6; or

b. make repairs so that emissions no longer exceed the criteria of Condition 6.2; to show that emissions are below those criteria, observe emissions as described in Condition 2.1 under load conditions comparable to those when the criteria were exceeded.

6.2. Conduct the PM source test or make repairs according to Condition 6.1 if

a. 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity greater than 20 percent; or

b. for an emission unit with an exhaust stack diameter that is less than 18 inches, 18 consecutive minutes of Method 9 observations result in an 18-minute average opacity that is greater than 15 percent and not more than 20 percent, unless the Department has waived this requirement in writing.

6.3. During each one-hour PM source test run, observe the exhaust for 60 minutes in accordance with Method 9 and calculate the average opacity measured during each one-hour test run. Submit a copy of these observations with the source test report.

6.4. The automatic PM source test requirement in Conditions 6.1 and 6.2 is waived for an emissions unit if a PM source test on that unit has shown compliance with the PM standard during this permit term.

7. Particulate Matter Recordkeeping for Diesel Engines. Within 180 calendar days after the effective date of this permit, the Permittee shall record the exhaust stack diameter of EU IDs 11, 12 and 18. Report the stack diameter(s) in the next operating report under Condition 63.

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(ii)]

8. Particulate Matter Reporting for Diesel Engines. The Permittee shall report as follows:

[18 AAC 50.040(j), 50.326(j), & 50.346(c)]
[40 C.F.R. 71.6(a)(3)(iii)]

8.1. Report under Condition 62

a. the results of any PM source test that exceed the PM emissions limit; or

b. if one of the criteria of Condition 6.2 was exceeded and the Permittee did not comply with either Condition 6.1.a or 6.1.b, this must be reported by the day following the day compliance with Condition 6.1 was required;

8.2. Report observations in excess of the threshold of Condition 6.2.b within 30 days of the end of the month in which the observations occur.

8.3. In each operating report under Condition 63, include:

a. the dates, EU ID(s), and results when an observed 18-minute average was greater than an applicable threshold in Condition 6.2;

b. a summary of the results of any PM testing under Condition 6; and

c. copies of any visible emissions observation results (opacity observations) greater than the thresholds of Condition 6.2, if they were not already submitted.

Visible Emissions & Particulate Matter MR&R for Dual Fuel Emission Units

9. The Permittee shall monitor, record, and report the monthly hours of operation when operating exclusively on ULSD.

9.1. For any of EU IDs 1 through 10, 13, and 14 that does not exceed 400 hours of operation per calendar year on ULSD, monitoring of compliance for visible and particulate matter emissions is not required for that EU and monitoring shall consist of an annual certification under Condition 64.

9.2. For any of EU IDs 1 through 10, 13, and 14, notify the Department and begin monitoring the affected emission unit(s) according to Condition 9.3 no later than 15 days after the end of a calendar month in which the cumulative hours of operation for the calendar year exceed any multiple of 400 hours on ULSD exclusively. If the observation exceeds the limit in Condition 1, monitor as described in Condition 6. If the observation does not exceed the limit in Condition 1, no additional monitoring is required until the cumulative hours of operation exceed each subsequent multiple of 400 hours on ULSD during a calendar year.[1]

9.3. When required to do so by Condition 9.2, observe the exhaust, following 40 C.F.R. 60, Appendix A-4 Method 9, adopted by reference in 18 AAC 50.040(a), for 18-minutes to obtain 72 consecutive 15-second opacity observations.

9.4. Keep records and report in accordance with Conditions 3, 4, 7, and/or 8, as applicable.

9.5. Report under Condition 62 if the Permittee fails to comply with Condition 9.2, 9.3 or 9.4.

[18 AAC 50.040(j) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3) & 71.6(c)(6)]

Sulfur Compound Emissions Standard

10. Sulfur Compound Emissions. In accordance with 18 AAC 50.055(c), the Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from EU IDs 1 through 14, 17, and 18 to exceed 500 ppm averaged over three hours.

[18 AAC 50.040(j), 50.055(c), & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

For Fuel Oil[2] (EU IDs 1 through 14 and 18)

10.1. **Sulfur Compound MR&R for Oil-Fired Emission Units**. For EU IDs 1 through 10, 13, and 14 (when operating exclusively on ULSD) and EU IDs 11, 12, and 18, to ensure compliance with Condition 10, the Permittee shall comply with the fuel sulfur content limit and associated monitoring, recordkeeping, and reporting (MR&R) requirements in Condition 11.2.

[Condition 15.2, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

[1] If the requirement to monitor is triggered more than once in a calendar month, only one Method 9 observation is required to be conducted by the stated deadline for that month.
[2] *Oil* means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil, as defined in 40 C.F.R. 60.41b, effective 7/1/07.

For Fuel Gas (EU IDs 1 through 10, 13, 14, and 17)

10.2. **Sulfur Compound MR&R for Gas-Fired Emission Units**. For EU IDs 1 through 10, 13, and 14 (when operating on natural gas) and EU ID 17, to ensure compliance with Condition 10, the Permittee shall comply with the fuel sulfur content limit and associated MR&R requirements in Condition 11.1.

[Condition 15.1, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3) & (c)(6)]

Preconstruction Permit[3] Requirements

Limits to Avoid Minor Permitting under 18 AAC 50.502(c)(1)(C)

11. Fuel Sulfur Requirements. The Permittee shall monitor the sulfur content of the ULSD and hydrogen sulfide (H_2S) content of the natural gas burned as follows.

11.1. The H_2S content of the natural gas burned in EU IDs 1 through 10, 13, 14, and 17 shall not exceed 20 parts per million by volume (ppmv).

a. Monitor and record the H_2S content of the natural gas monthly by obtaining and keeping a current certified letter, valid purchase contract, tariff sheet, or transportation contract from the supplier stipulating that the natural gas supplied during the month does not contain more than 20 ppmv H_2S.

b. Report in the operating report under Condition 63 the monthly H_2S content of the natural gas. Report under Condition 62 if the H_2S content of the natural gas exceeds 20 ppmv.

11.2. The sulfur content of the diesel fuel burned in EU IDs 1 through 10, 13, and 14 (when burning diesel) and in EU IDs 11, 12, and 18 shall not exceed 15 parts per million by weight (ppmw) of sulfur.

a. Monitor and record monthly the sulfur content of the diesel fuel burned by obtaining and keeping a current certified letter or fuel receipts from the diesel fuel supplier that the diesel fuel supplied during the month was ULSD.

b. Report in the operating report under Condition 63 the type of diesel fuel received for each shipment. Report under Condition 62 if the fuel received was not ULSD.

[Condition 15, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)]

[3] *Preconstruction Permit* refers to Federal PSD Permits, State-issued Permits-to-Operate issued before January 18, 1997 (these permits cover both construction and operations), Construction Permits issued after January 17, 1997, and Minor Permits issued after October 1, 2004.

Owner Requested Limits to Avoid Classification as PSD Major Source

12. **Operational Hour Limits for EU IDs 1 through 10.** The Permittee shall limit the combined hours of operation of EU IDs 1 through 10 to no more than 1,680 hours per 12-month rolling period when firing ultra-low sulfur diesel (ULSD) exclusively.

    12.1. The Permittee shall burn only natural gas and ULSD in EU IDs 1 through 10.

    12.2. Install and maintain a non-resettable hour meter on EU IDs 1 through 10.

    12.3. Monitor and record the hours of operation each month for each of EU IDs 1 through 10 when firing ULSD exclusively.

    12.4. By the end of each calendar month, calculate and record the combined hours of operation for EU IDs 1 through 10 during the previous month, then calculate the 12-month rolling combined hours for EU IDs 1 through 10 when firing ULSD exclusively.

    12.5. Report in the operating report under Condition 63 the rolling 12-month combined hours of operation for EU IDs 1 through 10 when firing ULSD exclusively.

    12.6. Notify the Department under Condition 62 if the consecutive 12-month combined hours of operation for EU IDs 1 through 10, when firing ULSD exclusively, exceed 1,680 hours.

[Condition 5, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)]

13. **Operational Hour Limits for EU ID 11:** The Permittee shall limit the operation of EU ID 11 to no more than 500 hours per year.

    13.1. Install and maintain a non-resettable hour meter on EU ID 11.

    13.2. Monitor and record the monthly hours of operation for EU ID 11.

    13.3. By the end of each month, calculate and record the operating hours of EU ID 11 for the previous month.

    13.4. Report in the operating report under Condition 63 the rolling 12-month hours of operation for EU ID 11.

    13.5. Notify the Department under Condition 62 if the rolling 12-month hours of operation for EU ID 11 exceed 500 hours.

[Condition 6, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)]

14. **Operational Hour Limits for EU IDs 13 and 14:** The Permittee shall limit the combined hours of operation of EU IDs 13 and 14 to no more than 1,000 hours per rolling 12-month period when firing ULSD exclusively.

    14.1. The Permittee shall fire only natural gas and ULSD in EU IDs 13 and 14.

14.2. Install and maintain a non-resettable hour meter on each of EU IDs 13 and 14.

14.3. Monitor and record the monthly operating hours for each of EU IDs 13 and 14 when firing ULSD exclusively.

14.4. By the end of each month, calculate and record the combined operating hours of EU IDs 13 and 14 during the previous month, then calculate the rolling 12-month combined hours for EU IDs 13 and 14 when firing ULSD exclusively.

14.5. Report in the operating report under Condition 63 the rolling 12-month combined operating hours for EU IDs 13 and 14 when firing ULSD exclusively.

14.6. Notify the Department under Condition 62 if the rolling 12-month combined hours of operation for EU IDs 13 and 14, when firing ULSD exclusively, exceed 1,000 hours.

[Condition 7, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)]

15. **Control Equipment:** The Permittee shall operate and maintain a combined selective catalytic reduction (SCR) and catalytic oxidation (CATOX) control equipment downstream of each of EU IDs 1 through 10 according to the manufacturer's instructions and as follows:

15.1. For the combined control equipment[4], while operating on natural gas, monitor and record hourly:

a. the rate of injection of the reducing aqueous ammonia reagent into the flue gas leaving the emission unit. The 3-hour rolling average ammonia injection rate shall be no less than 1.0 gallons per hour (gal/hr) and no more than 38.5 gal/hr[5], except during startup and shutdown.

b. the temperature of the flue gas leaving the combined control equipment. The 3-hour rolling average temperature of the flue gas leaving the combined control equipment shall be no less than 536°F and no more than 997°F[6], except during startup and shutdown.

c. the pressure drop across the combined control equipment. The 3-hour rolling average pressure drop shall be no less than 1.5 inches of water and no more than 10 inches of water, except during startup and shutdown.

15.2. Keep on site the necessary manufacturer-recommended spare parts, reagents, catalysts, and operation manual for the control equipment.

15.3. In case of equipment malfunction, implement manufacturer-recommended corrective actions and record:

a. complete description of the corrective action; and

b. date(s) of the corrective action

[4] SCR and CATOX with the CATOX downstream of the SCR.
[5] The minimum injection rate is from the permit application; maximum injection rate is from the manufacturer's specifications.
[6] The temperature rates are from the manufacturer specifications.

15.4. Keep records of:

a. all control equipment system repairs;

b. hourly operating parameters established in Condition 15.1, dates and times each control equipment is started up or shut down;

c. system alarm logs including time and date of occurrence; and

d. receipts for all aqueous ammonia purchases (with dates and quantities).

15.5. Report under Condition 62 all:

a. control equipment malfunctions and associated corrective actions;

b. operating parameters that are outside the ranges in Condition 15.1; and

c. periods (starting and ending hour) during which a control equipment was not operating within the ranges established in Condition 15.1 while its associated generator was operating.

[Condition 8, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)]

Limit to Avoid Classification as HAP Major Source

16. Formaldehyde (CH_2O) Emission Limit: The Permittee shall limit CH_2O emissions from EU IDs 1 through 10 while firing natural gas to no more than 9.6 tpy during any consecutive 12 months by operating and maintaining the control equipment as described in Condition 15.

[Condition 9, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

Requirements for Ambient Air Quality Protection

17. Annual NO_2 Ambient Air Quality Protection: To protect the annual NO_2 ambient air quality standard, the Permittee shall:

17.1. For EU IDs 1 through 10, the Permittee shall maintain a release height for each stack that equals or exceeds 30.0 meters above grade.

[Condition 13, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

18. Annual NO_2 and 24-hr PM-10 Ambient Air Quality Protection: To protect the annual NO_2 and 24-hr PM-10, the combined operating hours for EU IDs 12 and 18 shall not exceed 1,000 hours per rolling 12-month period.

18.1. Install and maintain a non-resettable hour meter on each of EU IDs 12 and 18.

18.2. Monitor and record the hours of operation of each emission unit and the combined hours of operation for EU IDs 12 and 18 for each month.

18.3. At the end of each month, calculate and record for the previous month, the combined hours of operation for EU ID 12 and EU ID 18 during the month, then calculate the combined 12-month rolling total hours of operation by adding the hours of operation for the previous 11 months.

18.4. Report in the operating report under Condition 63 the combined rolling 12-month hours of operation for EU IDs 12 and 18.

18.5. Notify the Department under Condition 62 should the combined consecutive 12-month operating hours for EU IDs 12 and 18 exceed 1,000 hours.

[Condition 14, Minor Permit AQ1086MSS03, 11/6/2015]
[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(a)(1) & (a)(3)]

Insignificant Emission Units

19. For emission units at the stationary source that are insignificant as defined in 18 AAC 50.326(d)-(i) that are not listed in this permit, the following apply:

19.1. The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, emitted from an industrial process, fuel-burning equipment, or an incinerator to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

[18 AAC 50.050(a) & 50.055(a)(1)]

19.2. The Permittee shall not cause or allow particulate matter emitted from an industrial process or fuel-burning equipment to exceed 0.05 grains per cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

[18 AAC 50.055(b)(1)]

19.3. The Permittee shall not cause or allow sulfur compound emissions, expressed as SO_2, from an industrial process or fuel-burning equipment, to exceed 500 ppm averaged over three hours.

[18 AAC 50.055(c)]

19.4. General MR&R for Insignificant Emission Units

a. The Permittee shall submit the certification of compliance of Condition 64 based on reasonable inquiry;

b. The Permittee shall comply with the requirements of Condition 45;

c. The Permittee shall report in the operating report required under Condition 63 if an emission unit is insignificant because of actual emissions less than the thresholds of 18 AAC 50.326(e) and actual emissions become greater than any of those thresholds; and

d. No other monitoring, recordkeeping or reporting is required.

[18 AAC 50.346(b)(4)]

Section 4. Federal Requirements

40 C.F.R. Part 60 New Source Performance Standards (NSPS)

Subpart A – General Provisions

20. NSPS Subpart A Notification. For any affected facility[7] or existing facility[8] regulated under NSPS requirements in 40 C.F.R. 60, the Permittee shall furnish the Department and EPA written notification or, if acceptable to both the EPA and the Permittee, electronic notification as follows:

[18 AAC 50.035 & 50.040(a)(1)]
[40 C.F.R. 60.7(a) & 60.15(d), Subpart A]

20.1. A notification of the date that construction (or reconstruction as defined under 40 C.F.R. 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in complete form.

[40 C.F.R. 60.7(a)(1), Subpart A]

20.2. A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

[40 C.F.R. 60.7(a)(3), Subpart A]

20.3. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies unless that change is specifically exempted under an applicable subpart or in 40 C.F.R. 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include:

a. information describing the precise nature of the change,

b. present and proposed emission control systems,

c. productive capacity of the facility before and after the change, and

d. the expected completion date of the change;

[40 C.F.R. 60.7(a)(4), Subpart A]

20.4. A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 C.F.R. 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

[40 C.F.R. 60.7(a)(5), Subpart A]

[7] *Affected facility* means, with reference to a stationary source, any apparatus to which a standard applies, as defined in 40 C.F.R. 60.2.

[8] *Existing facility* means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type, as defined in 40 C.F.R. 60.2.

20.5. A notification of the anticipated date for conducting the opacity observations required by 40 C.F.R. 60.11(e)(1). The notifications shall also include, if appropriate, a request for the EPA to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

[40 C.F.R. 60.7(a)(6), Subpart A]

20.6. If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify EPA and the Department of the proposed replacements. The notice must be postmarked as soon as practicable, but no less than 60 days before commencement of replacement, and must include the following information:

[40 C.F.R. 60.15(d), Subpart A]

a. name and address of owner or operator,

b. the location of the existing facility,

c. a brief description of the existing facility and the components that are to be replaced,

d. a description of the existing and proposed air pollution control equipment,

e. an estimate of the fixed capital cost of the replacements, and of constructing a comparable entirely new facility,

f. the estimated life of the existing facility after the replacements, and

g. a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

21. **NSPS Subpart A Startup, Shutdown, & Malfunction Requirements**. The Permittee shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of EU ID(s) 1 through 14 and 18, any malfunction of the air-pollution control equipment, or any periods during which a continuous monitoring system or monitoring device for EU ID(s) 1 through 14 and 18 is inoperative.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.7(b), Subpart A]

22. **NSPS Subpart A Performance (Source) Tests.** The Permittee shall conduct source tests according to Section 6 and as required in this condition on any affected facility.

[18 AAC 50.040(a)(1)]

22.1. Except as specified in paragraphs (a)(1), (a)(2), (a)(3), and (a)(4) of 40 C.F.R. 60.8, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by 40 C.F.R. Part 60, and at such other times as may be required by EPA, the owner or operator of such facility shall conduct performance test(s) and furnish EPA and the Department a written report of the results of such performance test(s).

[40 C.F.R. 60.8(a), Subpart A]

22.2. Conduct source tests and reduce data as set out in 40 C.F.R. 60.8(b), and provide the Department copies of any EPA waivers or approvals of alternative methods.

[40 C.F.R. 60.8(b), Subpart A]

22.3. Conduct source tests under conditions specified by EPA to be based on representative performance of EU ID(s) 1 through 10. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

[40 C.F.R. 60.8(c), Subpart A]

22.4. Provide the EPA and the Department at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the EPA and the Department the opportunity to have an observer present. If after a 30 day notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the Permittee shall notify the EPA and the Department as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the EPA and the Department by mutual agreement.

[40 C.F.R. 60.8(d), Subpart A]

22.5. Provide or cause to be provided, performance testing facilities as follows:

a. Sampling ports adequate for test methods applicable to EU ID(s) 1 through 14 and 18. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

b. Safe sampling platform(s),

c. Safe access to sampling platform(s), and

d. Utilities for sampling and testing equipment.

[40 C.F.R. 60.8(e), Subpart A]

22.6. Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the EPA's approval, be determined using the arithmetic mean of the results of the two other runs.

[40 C.F.R. 60.8(f), Subpart A]

23. **NSPS Subpart A Good Air Pollution Control Practice.** At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate EU ID(s) 13 and 14 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. The Administrator will determine whether acceptable operating and maintenance procedures are being used based on information available, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance records, and inspections of EU ID(s) 13 and 14.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.11(d), Subpart A]

24. **NSPS Subpart A Credible Evidence.** For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of the standards set forth in Condition 26, 27, or 28 nothing in 40 C.F.R. Part 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether EU IDs 1 through 14 and 18 would have been in compliance with applicable requirements of 40 C.F.R. Part 60 if the appropriate performance or compliance test or procedure had been performed.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.11(g), Subpart A]

25. **NSPS Subpart A Concealment of Emissions.** The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of a standard set forth in Condition 26, 27, or 28. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[18 AAC 50.040(a)(1)]
[40 C.F.R. 60.12, Subpart A]

NSPS Subpart Dc – Steam Generating Units

NSPS Subpart Dc Applicability

26. For EU IDs 13 and 14, the Permittee shall comply with any applicable requirement in 40 C.F.R. 60 Subpart Dc for small steam generating units for which construction is commenced after June 9, 1989 and that has a maximum design capacity of 100 MMBtu/hr or less but greater than or equal to 10 MMBtu/hr.

[18 AAC 50.040(a)(2)(D), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.40c(a), Subpart Dc]

NSPS Subpart Dc Sulfur Dioxide Standard

26.1. At all times, including periods of startup, shutdown, and malfunction, when EU IDs 13 and 14 combust fuel oil, the Permittee shall **either**:

a. emit no more than 0.5 lb SO_2/MMBtu (215 ng/J) heat input from fuel oil combusted, **or**

b. combust fuel oil that contains no more than 0.5 percent sulfur by weight.

[18 AAC 50.040(a)(2)(D)]
[40 C.F.R. 60.42c(d) & (i), Subpart Dc]

NSPS Subpart Dc Monitoring, Recordkeeping, and Reporting Requirements

26.2. Compliance with the emission limits or fuel oil sulfur limits under Condition 26.1 shall be determined based on a certification from the fuel supplier and demonstrated by complying with Condition 11.2.

[40 C.F.R. 60.42c(h)(1), 60.44c(h), & 60.46c(e), Subpart Dc]

26.3. The Permittee shall maintain records consistent with Condition 58 and shall submit reports to EPA as follows:

a. Include the calendar dates covered in the reporting period and a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

[40 C.F.R. 60.48c(d), (e)(l) & (11), Subpart De]

b. Fuel supplier certification shall include the following information:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in 40 C.F.R. 60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

[40 C.F.R. 60.48c(f)(l), Subpart De]

c. The reporting period for the reports required under Condition 26.3 is each six-month period. All reports shall be submitted to the EPA and shall be postmarked by the 30th day following the end of the reporting period.

[40 C.F.R. 60.48c(j), Subpart Dc]

26.4. Except as provided under Condition 26.5, for each of EU IDs 13 and 14, the Permittee shall record the amount of each fuel combusted during each operating day and maintain the records consistent with Condition 58,

26.5. As an alternative to meeting the requirements of Condition 26.4, the Permittee may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

[18 AAC 50.040(a)(2)(D)]
[40 C.F.R. 60.48c(g)(1) & (2), Subpart Dc]

NSPS Subpart IIII – Compression Ignition Internal Combustion Engines

NSPS Subpart IIII Applicability and Compliance Requirements

27. For EU IDs 11, 12, and 18, listed in Table A, the Permittee shall comply with all applicable requirements in 40 C.F.R. 60 Subpart IIII for stationary compression ignition (CI) internal combustion engine (ICE) whose construction[9] commences after July 11, 2005 where the stationary CI ICE is manufactured after April 1, 2006 (for emergency units, EU IDs 12 and 18) and manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006 (for fire pump engine, EU ID 11).

[18 AAC 50.040(a)(2)(OO), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4200(a)(2), Subpart IIII]

27.1. Comply with the applicable requirements of 40 C.F.R. 60.4208 for importing or installing stationary CI ICE.

[40 C.F.R. 60.4208, Subpart IIII]

27.2. Except as permitted under Condition 27.3, operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions over the entire life of the engine. In addition, the Permittee may only change those settings that are permitted by the manufacturer.

[40 C.F.R. 60.4206 & 60.4211(a), Subpart IIII]

27.3. If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

[40 C.F.R. 60.4211(g), Subpart IIII]

[9] For the purposes of NSPS Subpart IIII, the date that construction commences is the date the engine is ordered by the owner or operator as defined in 40 C.F.R. 60.4200(a).

a. For EU IDs 11, 12, and 18, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrated compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

[40 C.F.R. 60.4211(g)(2) & (g)(3), Subpart IIII]

b. For EU IDs 12 and 18, conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[40 C.F.R. 60.4211(g)(3), Subpart IIII]

27.4. Operate EU IDs 11, 12, and 18 according to the requirements in 40 C.F.R. 60.4211(f)(1) through 40 C.F.R. 60.4211(f)(3). In order for the engine to be considered an emergency stationary ICE under NSPS Subpart IIII, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in 40 C.F.R. 60.4211(f)(1) through 40 C.F.R. 60.4211(f)(3), is prohibited. If you do not operate the engine according to the requirements in 40 C.F.R. 60.4211(f)(1) through 40 C.F.R. 60.4211(f)(3), the engine will not be considered an emergency engine under 40 C.F.R. 60 Subpart IIII and must meet all requirements for non-emergency engines.

[40 C.F.R. 60.4211(f), Subpart IIII]

27.5. Comply with the applicable provisions of NSPS Subpart A as specified in Table 8 to Subpart IIII.

[40 C.F.R. 60.4218 & Table 8, Subpart IIII]

NSPS Subpart IIII Fuel Requirements

27.6. For EU IDs 11, 12, and 18, the Permittee must use diesel fuel that meets the requirements of 40 C.F.R. 80.510(b) for nonroad diesel fuel with the following specifications:

a. a maximum sulfur content of 15 ppmw,

b. cetane index or aromatic content, as follows

(i) a minimum cetane number of 40, or

(ii) a maximum aromatic content of 35 percent by volume

[18 AAC (a)(2)(OO) & 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4207(b), Subpart IIII]
[40 C.F.R. 80.510(b), Subpart I]

NSPS Subpart IIII Emission Standards

27.7. The Permittee shall comply with the emission standards in Conditions 27.8 and 27.9 by purchasing an engine certified according to the emission standards specified in 40 C.F.R. 60.4205(b)(for EU IDs 12 and 18) and 60.4205(c) (for EU ID 11), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted under Condition 27.3.[10]

[18 AAC 50.040(a)(2)(OO), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]

27.8. [40 C.F.R. 60.4211(c), Subpart IIII]For EU IDs 12 and 18, the Permittee shall not exceed the following applicable exhaust emission standards for new nonroad CI engines in 40 C.F.R. 89.112 and 89.113 for all pollutants, for the same displacement and maximum engine power (i.e., Tier 2 emission standards):

a. 6.4 g/kW-hr for NMHC + NOx;

b. 3.5 g/KW-hr for CO;

c. 0.2 g/kW-hr for PM; and

d. Exhaust opacity from EU IDs 12 and 18 must not exceed:

(i) 20 percent during the acceleration mode;

(ii) 15 percent during the lugging mode; and

(iii) 50 percent during the peaks in either the acceleration or lugging modes.

18 AAC 50.040(a)(2)(OO), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4205(b) & 60.4202(a)(2), Subpart IIII]
[40 C.F.R. 89.112(a) & Table A-1 and 89.113(a), Subpart B]

27.9. For EU ID 11, the Permittee shall comply with the applicable emission standards in Table 4 to NSPS Subpart IIII, for all pollutants.

a. 4.0 g/kW-hr for NMHC + NOx;

b. 3.5 g/kW-hr for CO; and

c. 0.20 g/kW-hr for PM

[40 C.F.R. 60.4205(c) & Table 4, Subpart IIII]

[10] EU IDs 11, 12, and 18 were identified in the application as certified engines.

NSPS Subpart IIII Monitoring and Recordkeeping Requirements

27.10. For EU IDs 11, 12, and 18, the Permittee shall meet the monitoring and recordkeeping requirements as follows:

[18 AAC 50.040(a)(2)(OO), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)& (a)(3)]

a. If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine, if one is not already installed.

[40 C.F.R. 60.4209(a), Subpart IIII]

b. If you are an owner or operator of an emergency stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in Conditions 27.7 and 27.9, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

(i) Keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

[40 C.F.R. 60.4209(b) & 60.4214(c), Subpart IIII]

c. If the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

[40 C.F.R. 60.4214(b), Subpart IIII]

NSPS Subpart IIII Reporting Requirements

27.11. Include with the operating report under Condition 63 records of the operational hours and the reason the engine was in operation as required in Condition 27.10.c for the period covered by the report.

27.12. Report in accordance with Condition 62 if any of the requirements in Conditions 27.1 through 27.10 were not met.

[18 AAC 50.040(j)(4) & 50.326(j)(4)]
[40 C.F.R. 71.6(a)(3)(iii) & (c)(6)]

NSPS Subpart JJJJ – Spark Ignition Internal Combustion Engines

NSPS Subpart JJJJ Applicability and Compliance Requirements

28. For EU IDs 1 through 10, the Permittee shall comply with all applicable requirements of NSPS Subpart JJJJ for stationary spark ignition (SI) internal combustion engine whose construction, modification, or reconstruction commences after June 12, 2006.

[18 AAC 50.040(a)(2)(PP), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 60.4230, Subpart JJJJ]

28.1. Operate and maintain stationary SI ICE that achieve the emission standards as required in Condition 28.4 over the entire life of the engine.

[40 C.F.R. 60.4234, Subpart JJJJ]

28.2. Comply with the applicable provisions of NSPS Subpart A as specified in Table 3 to Subpart JJJJ.

[40 C.F.R. 60.4246 & Table 3, Subpart JJJJ]

28.3. For EU ID 1 through 10, the Permittee shall comply with the following:

a. You must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance with the emission standards in Condition 28.4.

[40 C.F.R. 60.4243(b)(2)(ii), Subpart JJJJ]

NSPS Subpart JJJJ Emission Standards

28.4. For EU IDs 1 through 10, the Permittee must meet the following emission standards:

[40 C.F.R. 60.4233(e), Subpart JJJJ]

a. 1.0 g/hp-hr (82 ppmvd at 15 percent O_2) for NOx

b. 2.0 g/hp-hr (270 ppmvd at 15 percent O_2) for CO

c. 0.7 g/hp-hr (60 ppmvd at 15 percent O_2) for VOC[11]

[40 C.F.R. 60.4233(e) & Table 1, Subpart JJJJ]

NSPS Subpart JJJJ Testing Requirements

28.5. For EU ID 1 through 10, the Permittee shall comply with the following:

[11] For purposes of NSPS Subpart JJJJ, when calculating emissions of volatile organic compounds from EU IDs 1-10, emissions of formaldehyde should not be included.[Table 1 Footnote d, Subpart JJJJ]

a. Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in Conditions 28.5.a(i) through 28.5.a(vii) below.

[40 C.F.R. 60.4244, Subpart JJJJ]

(i) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in 40 C.F.R. 60.8 and under the specific conditions that are specified by Table 2 to NSPS Subpart JJJJ.

(ii) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in 40 C.F.R. 60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.

(iii) You must conduct three separate test runs for each performance test required in this section, as specified in 40 C.F.R. 60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(iv) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 1 of 40 C.F.R. 60.4244.

(v) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of 40 C.F.R. 60.4244.

(vi) For purposes of NSPS Subpart JJJJ, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of 40 C.F.R. 60.4244.

(vii) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of 40 C.F.R. 60.4244. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of 40 C.F.R. 60.4244.

[40 C.F.R. 60.4244(a) through (g), Subpart JJJJ]

NSPS Subpart JJJJ Notification, Reporting, and Recordkeeping Requirements

28.6. For EU ID 1 through 10, the Permittee must meet the following notification, reporting and recordkeeping requirements.

[40 C.F.R. 60.4245, Subpart JJJJ]

a. Owners and operators of all stationary SI ICE must keep records of the information in Conditions 28.6.a(i) through 28.6.a(iii) of this permit.

[40 C.F.R. 60.4245(a), Subpart JJJJ]

(i) All notifications submitted to comply with NSPS Subpart JJJJ and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary SI ICE is not a certified engine, documentation that the engine meets the emission standards.

[40 C.F.R. 60.4245(a)(1), (2) & (4), Subpart JJJJ]

b. Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in Condition 28.5.a within 60 days after the test has been completed. Performance test reports using EPA Method 18, EPA Method 320, or ASTM D6348-03 (incorporated by reference - see 40 CFR 60.17) to measure VOC require reporting of all QA/QC data. For Method 18, report results from sections 8.4 and 11.1.1.4; for Method 320, report results from sections 8.6.2, 9.0, and 13.0; and for ASTM D6348-03 report results of all QA/QC procedures in Annexes 1-7

[40 C.F.R. 60.4245(d), Subpart JJJJ]

28.7. Report in accordance with Condition 62 if any of the requirements in Conditions 28.1 through 28.6 were not met.

40 C.F.R. Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Engines Subject to Federal NESHAP Subpart ZZZZ

29. NESHAP Subpart ZZZZ Applicability. For EU IDs 1 through 12 and 18, the Permittee shall comply with all applicable requirements of NESHAP Subpart ZZZZ for stationary reciprocating internal combustion engines (RICE) located at an area source of hazardous air pollutant (HAP) emissions.

[18 AAC 50.040(c)(23), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 63.6585(c) & 63.6590(a)(2)(iii), Subpart ZZZZ]

29.1. For EU IDs 11, 12, and 18, the Permittee shall meet the requirements of 40 C.F.R. 63 by meeting the requirements of 40 C.F.R. 60 Subpart IIII, for CI ICE, as set out in Conditions 27.1 through 27.12. No further requirements apply for EU IDs 11, 12, and 18 under 40 C.F.R. 63.

[18 AAC 50.040(c)(23), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 63.6590(c), Subpart ZZZZ]

29.2. For EU IDs 1 through 10, the Permittee shall meet the requirements of 40 C.F.R. 63 by meeting the requirements of 40 C.F.R. 60 Subpart JJJJ, for SI ICE, as set out in Conditions 28.1 through 28.6. No further requirements apply for EU IDs 1 through 10 under 40 C.F.R. 63.

[18 AAC 50.040(c)(23), (j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(1)]
[40 C.F.R. 63.6590(c)(1), Subpart ZZZZ]

40 C.F.R. Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Subpart A – General Provisions & Subpart M – Asbestos

30. The Permittee shall comply with the requirements set forth in 40 C.F.R. 61.145, 61.150, and 61.152 of Subpart M, and the applicable sections set forth in 40 C.F.R. 61, Subpart A and Appendix A.

[18 AAC 50.040(b)(1) & (2)(F), & 50.326(j)]
[40 C.F.R. 61, Subparts A & M, and Appendix A]

40 C.F.R. Part 82 Protection of Stratospheric Ozone

Subpart F – Recycling and Emissions Reduction

31. The Permittee shall comply with the standards for recycling and emission reduction of refrigerants set forth in 40 C.F.R. 82, Subpart F.

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82, Subpart F]

Subpart G – Significant New Alternatives Policy (Halon)

32. The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.174 (b)-(d) (Protection of Stratospheric Ozone Subpart G – Significant New Alternatives Policy Program).

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82.174(b)-(d), Subpart G]

Subpart H – Halon Emission Reduction

33. The Permittee shall comply with the applicable prohibitions set out in 40 C.F.R. 82.270 (b)-(f) (Protection of Stratospheric Ozone Subpart H – Halon Emission Reduction).

[18 AAC 50.040(d) & 50.326(j)]
[40 C.F.R. 82.270(b)-(f), Subpart H]

General NSPS and NESHAP Requirements

34. NESHAP Applicability Determinations. The Permittee shall determine rule applicability and designation of affected sources under National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories (40 C.F.R. 63) in accordance with the procedures described in 40 C.F.R. 63.1(b) and 63.10(b)(3). If a source becomes affected by an applicable subpart of 40 C.F.R. 63, the Permittee shall comply with such standard by the compliance date established by the Administrator in the applicable subpart, in accordance with 40 C.F.R. 63.6(c).

34.1. After the effective date of any relevant standard promulgated by the Administrator under this part, an owner or operator who constructs a new affected source that is not major-emitting or reconstructs an affected source that is not major-emitting that is subject to such standard, or reconstructs a source such that the source becomes an affected source subject to the standard, must notify the Administrator and the Department of the intended construction or reconstruction. The notification must be submitted in accordance with the procedures in 40 C.F.R. 63.9(b).

[18 AAC 50.040(c)(1), 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(ii)]
[40 C.F.R. 63.1(b), 63.5(b)(4), 63.6(c)(1), & 63.10(b)(3)]

35. NSPS and NESHAP Reports. The Permittee shall:

35.1. **Reports:** Except for federal reports and notices submitted through EPA's CDX/CEDRI on-line reporting system, attach to the operating report required under Condition 63 for the period covered by the report, a copy of any NSPS and NESHAPs reports submitted to the U.S. Environmental Protection Agency (EPA) Region 10; and

35.2. **Waivers**: Upon request by the Department, provide a written copy of any EPA-granted alternative monitoring requirement, custom monitoring schedule or waiver of the federal emission standards, recordkeeping, monitoring, performance testing, or reporting requirements. The Permittee shall keep a copy of each U.S. EPA issued monitoring waiver or custom monitoring schedule with the permit.

[18 AAC 50.326(j)(4) & 50.040(j)]
[40 C.F.R. 60.13, 63.10(d) & (f), & 71.6(c)(6)]

Section 5. General Conditions

Standard Terms and Conditions

36. 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.

[18 AAC 50.326(j)(3), 50.345(a) & (e)]

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

[18 AAC 50.326(j)(3), 50.345(a) & (f)]

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

[18 AAC 50.326(j)(3), 50.345(a) & (g)]

39. Administration Fees. The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400-403.

[18 AAC 50.326(j)(1), 50.400, & 50.403]
[AS 37.10.052(b), 11/04; AS 46.14.240, 6/7/03]

40. 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. 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

40.1. the stationary source's assessable potential to emit of **796 tpy**; or

40.2. 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; or

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

[18 AAC 50.040(j)(3), 50.035, 50.326(j)(1), 50.346(b)(1), 50.410, & 50.420]
[40 C.F.R. 71.5(c)(3)(ii)]

41. Assessable Emission Estimates. Emission fees will be assessed as follows:

41.1. no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., P.O. Box 111800, Juneau, AK 99811-1800; the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

41.2. 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 40.1.

[18 AAC 50.040(j)(3), 50.326(j)(1), 50.346(b)(1), 50.410, & 50.420]
[40 C.F.R. 71.5(c)(3)(ii)]

42. Good Air Pollution Control Practice. The Permittee shall do the following for EU IDs 13, 14, and 17:

42.1. perform regular maintenance considering the manufacturer's or the operator's maintenance procedures;

42.2. keep records of any maintenance that would have a significant effect on emissions; the records may be kept in electronic format; and

42.3. keep a copy of either the manufacturer's or the operator's maintenance procedures.

[18 AAC 50.030; 18 AAC 50.326(j)(3); 18 AAC 50.346(b)(5)]

43. Dilution. The Permittee shall not dilute emissions with air to comply with this permit. Monitoring shall consist of an annual certification that the Permittee does not dilute emissions to comply with this permit.

[18 AAC 50.045(a)]

44. Stack Injection. The Permittee shall not release materials other than process emissions, products of combustion, or materials introduced to control pollutant emissions from a stack at a source constructed or modified after November 1, 1982, except as authorized by a construction permit, Title V permit, or air quality control permit issued before October 1, 2004.

[18 AAC 50.055(g)]

45. 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.

[18 AAC 50.110, 50.040(e), 50.326(j)(3), and 50.346(a)]
[40 C.F.R. 71.6(a)(3)]

45.1. Monitoring, Recordkeeping, and Reporting for Condition 45:

a. If emissions present a potential threat to human health or safety, the Permittee shall report any such emissions according to Condition 62.

b. 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 45.

45.2. 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 an investigation because of a complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 45; or

b. the Department notifies the Permittee that it has found a violation of Condition 45.

45.3. The Permittee shall keep records of

a. the date, 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 45; and

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

45.4. With each operating report under Condition 63, the Permittee shall include a brief summary report 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.

45.5. 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.

46. Technology-Based Emission Standard. If an unavoidable emergency, malfunction, or non-routine repair, as defined in 18 AAC 50.235(d), causes emissions in excess of a technology-based emission standard[12] listed in Condition 26, 27, 28, or 31 (refrigerants), the Permittee shall take all reasonable steps to minimize levels of emissions that exceed the standard. Excess emissions reporting under Condition 62 requires information on the steps taken to minimize emissions. Monitoring of compliance for this condition consists of the report required under Condition 62.

[18 AAC 50.235(a), 50.326(j)(4), & 50.040(j)(4)]
[40 C.F.R. 71.6(c)(6)]

Open Burning Requirements

47. Open Burning. If the Permittee conducts open burning at this stationary source, the Permittee shall comply with the requirements of 18 AAC 50.065.

47.1. The Permittee shall keep written records to demonstrate that the Permittee complies with the limitations in this condition and the requirements of 18 AAC 50.065. Upon request by the Department, submit copies of the records.

47.2. Compliance with this condition shall be an annual certification conducted under Condition 64.

[18 AAC 50.065, 50.040(j), & 50.326(j)]
[40 C.F.R. 71.6(a)(3)]

[12] *Technology-based emission standard* means a best available control technology standard (BACT); a lowest achievable emission rate standard (LAER); a maximum achievable control technology standard established under 40 C.F.R. 63, Subpart B, adopted by reference in 18 AAC 50.040(c); a standard adopted by reference in 18 AAC 50.040(a) or (c); and any other similar standard for which the stringency of the standard is based on determinations of what is technologically feasible, considering relevant factors.

Section 6. General Source Testing and Monitoring Requirements

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

[18 AAC 50.220(a) & 50.345(a) & (k)]

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

[18 AAC 50.220(b)]

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

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

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

50.1. Source testing for compliance with requirements adopted by reference in 18 AAC 50.040(c) must be conducted in accordance with the source test methods and procedures specified in 40 C.F.R. 63.

[18 AAC 50.040(c) & 50.220(c)(1)(C)]
[40 C.F.R. 63]

50.2. Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in Reference Method 9 and may use the form in Section 11 to record data.

[18 AAC 50.030 & 50.220(c)(1)(D)]

50.3. 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.

[18 AAC 50.040(a)(3) & 50.220(c)(1)(E)]
[40 C.F.R. 60, Appendix A]

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

[18 AAC 50.035(b)(2) & 50.220(c)(1)(F)]
[40 C.F.R. 51, Appendix M]

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

[18 AAC 50.040(c)(24) & 50.220(c)(2)]
[40 C.F.R. 63, Appendix A, Method 301]

51. **Excess Air Requirements.** To determine compliance with this permit, standard exhaust gas volumes must include only the volume of gases formed from the theoretical combustion of the fuel, plus the excess air volume normal for the specific emission unit type, corrected to standard conditions (dry gas at 68° F and an absolute pressure of 760 millimeters of mercury).

[18 AAC 50.220(c)(3) & 50.990(102)]

52. **Test Exemption.** The Permittee is not required to comply with Conditions 54, 55 and 56 when the exhaust is observed for visible emissions by Method 9 Plan (Condition 2.1) or Smoke/No Smoke Plan (Condition 2.2).

[18 AAC 50.345(a)]

53. **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.

[18 AAC 50.345(a) & (l)]

54. **Test Plans.** Except as provided in Condition 52, 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 emission unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete plan within 60 days after receiving a request under Condition 48 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 performed without resubmitting the plan.

[18 AAC 50.345(a) & (m)]

55. **Test Notification.** Except as provided in Condition 52, at least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and the time the source test will begin.

[18 AAC 50.345(a) & (n)]

56. **Test Reports.** Except as provided in Condition 52, within 60 days after completing a source test, the Permittee shall submit two copies 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 in the manner set out in Condition 59. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

[18 AAC 50.345(a) & (o)]

57. Particulate Matter Calculations. In source testing for compliance with the particulate matter standards in Conditions 5 and 19.2, the three-hour average is determined using the average of three one-hour test runs. The source testing must account for those emissions caused by soot blowing, grate cleaning, or other routine maintenance activities by ensuring that at least one test run includes the emissions caused by the routine maintenance activity and is conducted under conditions that lead to representative emissions from that activity. The emissions must be quantified using the following equation:

$$E = E_M\left[(A+B)\times\frac{S}{R\times A}\right]+E_{NM}\left[\frac{R-S}{R}-B\times\frac{S}{R\times S}\right]$$

Where:

E	=	the total PM emissions of the emission unit in grains per dry standard cubic foot ((gr.)/dscf)
E_M	=	the PM emissions in (gr.)/dscf measured during the test that included the routine maintenance activity
E_{NM}	=	the arithmetic average of PM emissions in (gr.)/dscf measured during the test runs that did not include the maintenance activity
A	=	the period of routine maintenance activity occurring during the test run that included routine maintenance activity, expressed to the nearest hundredth of an hour
B	=	the total period of the test run, less A
R	=	the maximum period of emission unit operation per 24 hours, expressed to the nearest hundredth of an hour
S	=	the maximum period of routine maintenance activity per 24 hours, expressed to the nearest hundredth of an hour

[18 AAC 50.220(f)]

Section 7. General Recordkeeping and Reporting Requirements

Recordkeeping Requirements

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

[18 AAC 50.040(a)(1) & 50.326(j)]
[40 C.F.R 60.7(f), Subpart A, 40 C.F.R 71.6(a)(3)(ii)(B)]

58.1. Copies of all reports and certifications submitted pursuant to this section of the permit; and

58.2. Records of all monitoring required by this permit, and information about the monitoring including:

a. the date, place, and time of sampling or measurements;

b. the date(s) analyses were performed;

c. the company or entity that performed the analyses;

d. the analytical techniques or methods used;

e. the results of such analyses; and,

f. the operating conditions as existing at the time of sampling or measurement.

Reporting Requirements

59. 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 emission 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.

59.1. 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 59.1.a, that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.

[18 AAC 50.345(a) & (j), 50.205, & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

60. Submittals. Unless otherwise directed by the Department or this permit, the Permittee shall submit one copy of each report, compliance certification, and/or other submittal required by this permit, certified in accordance with Condition 59, to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The documents may be submitted either by hard copy or electronically.

60.1. Electronic submittals may be provided, upon consultation with the Compliance Technician or Department website regarding software compatibility, as follows:

a. send by E-mail under a cover letter using dec.aq.airreports@alaska.gov; or

b. use the Department's Air Online Services at http://dec.alaska.gov/applications/air/airtoolsweb/.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

61. 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 and 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.

[18 AAC 50.345(a) & (i), 50.200, & 50.326(a) & (j)]
[40 C.F.R. 71.5(a)(2) & 71.6(a)(3)]

62. Excess Emissions and Permit Deviation Reports.

62.1. Except as provided in Condition 45, 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 non-routine repair that causes emissions in excess of a technology based emission standard;

c. report all other excess emissions and permit deviations

(i) within 30 days of the end of the month in which the excess emissions or deviation occurred, except as provided in Conditions 62.1.c(ii) and 62.1.c(iii);

(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 62.1.c(i); and

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

62.2. When reporting excess emissions or permit deviations, the Permittee shall report using either the Department's on-line form, which can be found at http://www.dec.state.ak.us/air/ap/site.htm or if the Permittee prefers, the form contained in Section 12 of this permit. The Permittee must provide all information called for by the form that is used.

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

[18 AAC 50.235(a)(2), 50.240(c), 50.326(j)(3), & 50.346(b)(2) & (3)]

63. Operating Reports. During the life of this permit[13], the Permittee shall submit to the Department an operating report by August 1 for the period January 1 to June 30 of the current year and by February 1 for the period July 1 to December 31 of the previous year.

63.1. 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.

63.2. When excess emissions or permit deviations that occurred during the reporting period are not included with the operating report under Condition 63.1, 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 preventive measures taken and the date(s) of such actions; or

63.3. when excess emissions or permit deviations have already been reported under Condition 62 the Permittee shall cite the date or dates of those reports.

63.4. The operating report must include a listing of emissions monitored under Conditions 2.1.e and 2.2.c, which trigger additional testing or monitoring, whether or not the emissions monitored exceed an emission standard. The Permittee shall include in the report.

a. the date of the emissions;

b. the equipment involved;

c. the permit condition affected; and

[13] *Life of this permit* is defined as the permit effective dates, including any periods of reporting obligations that extend beyond the permit effective dates. For example if a permit expires prior to the end of a calendar year, there is still a reporting obligation to provide operating reports for the periods when the permit was in effect.

d. the monitoring result which triggered the additional monitoring.

[18 AAC 50.346(a) & 50.326(j)]
[40 C.F.R. 71.6(a)(3)(iii)(A)]

64. Annual Compliance Certification. Each year by March 31, the Permittee shall compile and submit to the Department an annual compliance certification report.

64.1. Certify the compliance status of the stationary source over the preceding calendar year consistent with the monitoring required by this permit, as follows:

a. identify each term or condition set forth in Section 3 through Section 9, that is the basis of the certification;

b. briefly describe each method used to determine the compliance status

c. state whether compliance is intermittent or continuous; and

d. identify each deviation and take it into account in the compliance certification;

64.2. In addition, submit a copy of the report directly to the EPA-Region 10, Office of Air Quality, M/S OAQ-107, 1200 Sixth Avenue, Seattle, WA 98101.

[18 AAC 50.205, 50.345(a) & (j), & 50.326(j)]
[40 C.F.R. 71.6(c)(5)]

65. Emission Inventory Reporting. The Permittee shall submit to the Department reports of actual emissions, by emission unit, of CO, NH_3, NO_X, PM-10, PM-2.5, SO_2, VOCs and Lead (Pb) (and lead compounds) using the form in Section 13 of this permit, as follows:

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

a. 250 tons per year (tpy) of NH_3, PM-10, PM-2.5_5 or VOCs; or

b. 2500 tpy of CO, NO_X or SO_2.

65.2. Every third year by April 30 if the stationary source's potential to emit for the previous calendar year equals or exceeds:

a. 5 tons per year of lead (Pb), or

b. 1000 tpy of CO; or

c. 100 tpy of SO_2, NH_3, PM-10, PM-2.5_5, NO_X or VOCs.

65.3. For reporting under Condition 65, the Permittee shall report in 2015 for calendar year 2014, 2018 for calendar year 2017, 2021 for calendar year 2020, etc., in accordance with the Environmental Protection Agency set schedule.

65.4. Include in the report required by this condition, the required data elements contained within the form in Section 13 or those contained in Table 2A of Appendix A to Subpart A of 40 C.F.R. 51 for each stack associated with an emission unit.

[18 AAC 50.346(b)(8) & 50.200]
[40 C.F.R. 51.15, 51.30(a)(1) & (b)(1) & 40 C.F.R. 51, Appendix A to Subpart A]

Section 8. Permit Changes and Renewal

66. Permit Applications and Submittals. The Permittee shall comply with the following requirements for submitting application information to the EPA Region 10:

66.1. The Permittee shall provide a copy of each application for modification or renewal of this permit, including any compliance plan, or application addenda, at the time the application or addendum is submitted to the Department[14];

66.2. The information shall be submitted to the same address as in Condition 64.2.

66.3. To the extent practicable, the Permittee shall provide to EPA applications in portable document format (PDF); MS Word format (.doc); or other computer-readable format compatible with EPA's national database management system; and

66.4. The Permittee shall maintain records as necessary to demonstrate compliance with this condition.

[18 AAC 50.040(j)(7) & 50.326(b)]
[40 C.F.R. 71.10(d)(1)]

67. Emissions Trading. No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in the permit.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(8)]

68. Off Permit Changes. The Permittee may make changes that are not addressed or prohibited by this permit other than those subject to the requirements of 40 C.F.R. Part 72 through 78 or those that are modifications under any provision of Title I of the Act to be made without a permit revision, provided that the following requirements are met:

68.1. Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition;

68.2. Provide contemporaneous written notice to EPA and the Department of each such change, except for changes that qualify as insignificant under 18 AAC 50.326(d) – (i). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change;

68.3. The change shall not qualify for the shield under 40 C.F.R. 71.6(f);

[14] The documents required in Condition 66.1 are submitted to the Department's Anchorage office. The current address for the Anchorage office is: ADEC, 555 Cordova Street, Anchorage, AK 99501.

68.4. The Permittee shall keep a record describing changes made at the stationary source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(12)]

69. Operational Flexibility. The Permittee may make Section 502(b)(10)[15] changes within the permitted stationary source without requiring a permit revision if the changes are not modifications under any provision of Title I of the Act and the changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emissions or in terms of total emissions):

69.1. The Permittee shall provide EPA and the Department with a notification no less than 7 days in advance of the proposed change.

69.2. For each such change, the written notification required above shall include a brief description of the change within the permitted stationary source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change.

69.3. The permit shield described in 40 C.F.R. 71.6(f) shall not apply to any change made pursuant to Condition 69.

[18 AAC 50.040(j)(4) & 50.326(j)]
[40 C.F.R. 71.6(a)(13)]

70. Permit Renewal. To renew this permit, the Permittee shall submit an application under 18 AAC 50.326 no sooner than July 26, 2020 and no later than July 26, 2021. The renewal application shall be complete before the permit expiration date listed on the cover page of this permit. Permit expiration terminates the stationary source's right to operate unless a timely and complete renewal application has been submitted consistent with 40 C.F.R. 71.7(b) and 71.5(a)(1)(iii).

[18 AAC 50.040(j)(3), 50.326(c)(2) & (j)(2)]
[40 C.F.R. 71.5(a)(1)(iii) & 71.7(b) & (c)(1)(ii)]

[15] As defined in 40 C.F.R. 71.2, Section 502(b)(10) changes are changes that contravene an express permit term. Such changes do not include changes that would violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements.

Section 9. Compliance Requirements

General Compliance Requirements

71. Compliance with permit terms and conditions is considered to be compliance with those requirements that are

71.1. included and specifically identified in the permit; or

71.2. determined in writing in the permit to be inapplicable.

[18 AAC 50.326(j)(3) & 50.345(a) & (b)]

72. 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

a. an enforcement action;

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

c. denial of an operating permit renewal application.

[18 AAC 50.040(j), 50.326(j) & 50.345(a) & (c)]

73. For applicable requirements with which the stationary source is in compliance, the Permittee shall continue to comply with such requirements.

[18 AAC 50.040(j) & 50.326(j)]
[40 C.F.R. 71.6(c)(3) & 71.5(c)(8)(iii)(A)]

74. 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.

[18 AAC 50.326(j)(3) & 50.345(a) & (d)]

75. 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

75.1. enter upon the premises where a source subject to the permit is located or where records required by the permit are kept;

75.2. have access to and copy any records required by the permit;

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

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

[18 AAC 50.326(j)(3) & 50.345(a) & (h)]

Section 10. Permit As Shield from Inapplicable Requirements

In accordance with AS 46.14.290, and based on information supplied in the permit application, this section of the permit contains the requirements determined by the Department not to be applicable to the stationary source.

76. Nothing in this permit shall alter or affect the following:

76.1. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section; or

76.2. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(f)(3)(i)) & (ii)]

77. Table B identifies the emission units that are not subject to the specified requirements at the time of permit issuance. If any of the requirements listed in Table B becomes applicable during the permit term, the Permittee shall comply with such requirements on a timely basis including, but not limited to, providing appropriate notification to EPA, obtaining a construction permit and/or an operating permit revision.

[18 AAC 50.326(j)]
[40 C.F.R. 71.6(f)(1)(ii)]

Table B - Permit Shields Granted

EU ID	Non-Applicable Requirements	Reason for Non-Applicability
1 - 10	40 C.F.R. 60 Subpart IIII – Standards of Performance for Stationary CI ICE	EUs are dual fuel, spark ignition engines, not compression ignition.
13 & 14	40 C.F.R. 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units	EUs have a heat input less than 250 MMBtu/hr and are therefore exempt per 40 C.F.R. 60.40Da(e)(1).
13 & 14	40 C.F.R. 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	EUs have a heat input less than 100 MMBtu/hr and are therefore exempt per 40 C.F.R. 60.40b(a).
13, 14, & 17	40 C.F.R. 63 Subpart DDDDD – NESHAP for major sources: industrial, commercial, and institutional boilers and process heaters	EUs are not located at a major source of HAP and are therefore exempt per 40 C.F.R. 63.7485.
13 & 14	40 C.F.R. 60 Subpart JJJJJJ – NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources	EUs meet definition of gas fired boiler and are therefore exempt per 40 C.F.R. 63.11195(e).
15 & 16	40 C.F.R. 60 Subpart K – Standards of Performance for Storage Vessels for Petroleum Liquids	Tanks were constructed after the 1978 applicability date.
15 & 16	40 C.F.R. 60 Subpart Ka – Standards of Performance for Storage Vessels for Petroleum Liquids	Tanks were constructed after the 1984 applicability date.
15 & 16	40 C.F.R. 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage	Tanks are exempt per 40 C.F.R. 60.110b(b)

EU ID	Non-Applicable Requirements	Reason for Non-Applicability
	Vessels)	
Stationary source-wide	40 CFR 60 Subparts C, Cb, Cc, Cd, Ce, D, Da, Db, E, Ea, Eb, Ec, F, G, Ga, H, I, J, Ja, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, VVa, WW, XX, AAA, BBB, DDD, FFF, GGG, GGGa, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, WWW, AAAA, BBB, CCCC, DDD, EEEE, FFFF, KKKK, LLLL, MMMM, OOOO, QQQQ, TTTT, UUUU	Not an affected stationary source, operation, or industry.
Stationary source-wide	40 CFR 61 Subpart A, B, C, D, E, F, H, I, J, K, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF	No affected EUs within the stationary source.
Stationary source-wide	40 C.F.R. 63 Subpart B, F, G, H, I, J, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, YYYY, AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS, TTTTT, UUUUU, WWWWW, YYYYY, ZZZZZ, BBBBBB, CCCCCC, DDDDDD, EEEEEE, FFFFFF, GGGGGG, HHHHHH, JJJJJJ, LLLLLL, MMMMMM, NNNNNN, OOOOOO, PPPPPP, QQQQQQ, RRRRRR, SSSSSS, TTTTTT, VVVVVV, WWWWWW, XXXXXX, YYYYYY, ZZZZZZ, AAAAAAA, BBBBBBB, CCCCCCC, DDDDDDD, EEEEEEE, HHHHHHH	Not an affected stationary source, operation, or industry.
Stationary source-wide	40 C.F.R. 68 Subpart C	Stationary source does not use aqueous ammonia with a concentration of 20% or greater.
Stationary source-wide	40 C.F.R. 51.308(e) and 40 C.F.R. 51 Appendix Y Guidelines for BART Determinations under the Regional Haze Rule	Stationary source is not an “existing stationary facility” as defined in 40 C.F.R. 51.301.
Stationary source-wide	40 C.F.R. 82 Subpart B	Stationary source and its employees do not perform service on motor vehicle air conditioners, for consideration or otherwise.
Stationary source-wide	18 AAC 50.055(a)(2)-(a)(9)	The stationary source does not contain any EUs subject to these opacity standards.
Stationary source-wide	18 AAC 50.055(b)(2)-(b)(6)	The stationary source does not contain any EUs subject to these particulate matter standards.
Stationary source-wide	18 AAC 50.055(d)-(f)	The stationary source does not contain any EUs subject to these sulfur standards.
Stationary source-wide	18 AAC 50.060, 50.070, 50.075, 50.076, 50.077, 50.085, 50.090	The stationary source is not an affected source regulated by these standards.

[18 AAC 50.326(j)][40 C.F.R. 71.6(f)(1)(ii)]

Section 11. Visible Emissions Forms

VISIBLE EMISSION OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, "Visual Determination of the Opacity of Emissions form 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.
- Stationary 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 clinometer.
- 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 PERMITS PROGRAM - VISIBLE EMISSIONS OBSERVATION FORM

Page No.___________

Stationary Source Name | Type of Emission Unit

Emission Unit Location

City | State | Zip

Phone # (Key Contact) | Stationary Source ID Number

Process Equipment | Operating Mode

Control Equipment | Operating Mode

Describe Emission Point/Location

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

Distance From Observer (Start / End) | Direction From Observer (Start / End)

Describe Emissions & Color (Start / End)

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

Point in Plume at Which Opacity Was Determined

Describe Plume Background (Start / End) | Background Color (Start / End)

Sky Conditions: (Start / End)

Wind Speed (Start / End) | Wind Direction From (Start / End)

Ambient Temperature | Wet Bulb Temp | RH percent

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

Observation Date | Start Time | End Time

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
Observer's Affiliation:
Certifying Organization
Certified By: | Date

Data Reduction:

Duration of Observation Period (minutes):	Duration Required by Permit (minutes):
Number of Observations:	Highest Six–Minute Average Opacity (%):
Number of Observations exceeding 20%:	
In compliance with six-minute opacity limit? (Yes or No)	Highest 18-Consecutive –Minute Average Opacity (%)(engines and turbines only)

Average Opacity Summary:

Set Number	Time			Opacity		Comments
	Start	End		Sum	Average	

Section 12. ADEC Notification Form

Eklutna Generation Station	AQ1086TVP01
Stationary Source (Facility) Name	**Air Quality Permit Number**
Matanuska Electric Association, Inc.	
Company Name	**Date**

When did you discover the Excess Emissions/Permit Deviation?

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

When did the event/deviation occur?

Begin Date: _____ / _____ / ________ Time: ______ : _______ (please use 24-hr clock)

End Date _____ / _____ / ________ Time: ______ : _______ (please 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 Condition – Complete Section 2 and Certify

☐ Deviations 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 ☐ Schedule Maintenance/Equipment Adjustment

☐ 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) Emissions Units Involved:
Identify the emission unit involved in the event, using the same identification number and name <u>as in the permit</u>. 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 ☐ Recordkeeping

☐ Marine Vessel Opacity ☐ 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

☐ Failure to Monitor/Report

☐ General Source Test/Monitoring Requirements

☐ Recordkeeping/Reporting/Compliance Certification

☐ Standard Conditions Not Included in the Permit

☐ Generally Applicable Requirements

☐ Reporting/Monitoring for Diesel Engines

☐ Insignificant Emission Unit

☐ Stationary Source Wide

☐ Other Section: ______________________________________ (Title of section and section number of your permit).

(b) Emission Unit Involved:

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

EU ID	EU 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. Fax to: 907-451-2187; or

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

If faxed or emailed, the report must be certified within the Operating Report required for the same reporting period per Condition 63.

Or

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

Or

4. Phone Notifications: 907-451-5173

Phone notifications require a written follow-up report.

Or

5. Submission of information contained in this report can be made electronically at the following website: *http://dec.alaska.gov/Applications/Air/airtoolsweb/*

If submitted online, report must be submitted by an authorized E-Signer for the stationary source.

[18 AAC 50.346(b)(3)]

Section 13. Emission Inventory Form

<table>
<tr><td colspan="2">ADEC Reporting Form
Emission Inventory Reporting

State of Alaska Department of Environmental Conservation
Division of Air Quality</td><td colspan="2">Emission Inventory
Year-[ ]</td></tr>
<tr><td colspan="4">Mandatory information is highlighted in bright yellow. Make additional copies as needed.</td></tr>
<tr><td colspan="4">Stationary Source Detail</td></tr>
<tr><td>Inventory start date</td><td colspan="3"></td></tr>
<tr><td>Inventory end date</td><td colspan="3"></td></tr>
<tr><td>ADEC ID or Permit Number</td><td colspan="3"></td></tr>
<tr><td>EPA ID:</td><td colspan="3"></td></tr>
<tr><td>Census Area/ Community</td><td colspan="3"></td></tr>
<tr><td>Facility Name</td><td colspan="3"></td></tr>
<tr><td rowspan="5">Facility Physical Location</td><td colspan="3">Address:</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">City, State, Zip Code:</td></tr>
<tr><td>Latitude:</td><td colspan="2">Longitude:</td></tr>
<tr><td colspan="3">Legal Description:</td></tr>
<tr><td rowspan="3">Owner Name & Address & contact number</td><td colspan="3">Owner Name:</td></tr>
<tr><td colspan="3">Owner Address:</td></tr>
<tr><td colspan="3">Phone Number:</td></tr>
<tr><td rowspan="3">Mailing Contact Information</td><td colspan="3">Mailing Address:</td></tr>
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<tr><td>Line of Business (NAICS)</td><td colspan="3"></td></tr>
<tr><td>Line of Business (SIC)</td><td colspan="3"></td></tr>
<tr><td>Facility Status:</td><td colspan="3"></td></tr>
</table>

Emission Unit Data			
Specifications			
ID		**Design Capacity**	
Description			
Emission 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 (%)	H_2S 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 Source	Tons
Carbon Monoxide (CO)					
Nitrogen Oxides NOx					
PM10 Primary (PM10-PRI)					
PM2.5 Primary (PM25-PRI)					
Sulfur Dioxide (SO2)					
Ammonia (NH3)					
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 (%)**	**H_2S 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 Source**	**Tons**
Carbon Monoxide (CO)					
Nitrogen Oxides NOx					
PM10 Primary (PM10-PRI)					
PM2.5 Primary (PM25-PRI)					
Sulfur Dioxide (SO2)					
Ammonia (NH3)					
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 (acfm)	
> 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. Fax this form to: 907-465-5129; or
2. E-mail to: DEC.AQ.airreports@alaska.gov; or
3. Mail to: ADEC
   Air Permits Program
   410 Willoughby Ave., Suite 303
   PO Box 111800
   Juneau, AK 99811-1800

Or

4. Submission of information can be made via a full electronic batch submittal (XML files). This will require each data element to be tagged with XML (Extensible Markup Language) code before it can be uploaded to ADEC database.
   http://dec.alaska.gov/Applications/Air/airtoolsweb/

[18 AAC 50.346(b)(9)]

MATANUSKA ELECTRIC ASSOCIATION

March 26, 2019

ADEC AIR QUALITY
RECEIVED
MAR 29 2019
ANCHORAGE

CERTIFIED MAIL 7016 3010 0000 6810 7091
Return Receipt Requested

Alaska Department of Environmental Conservation
Air Permits Program
ATTN: Assessable Emissions Estimate
410 Willoughby Avenue
P.O. Box 111800
Juneau, AK 99811-1800

Subject: FY 2020 Assessable Emissions Estimate
Matanuska Electric Association – Eklutna Generation Station
Air Quality Operating Permit No. AQ1086TVP01

To Whom It May Concern,

Matanuska Electric Association (MEA) is submitting the enclosed fiscal year (FY) 2020 assessable emissions estimate for the Eklutna Generation Station in accordance with Condition 41.1 of Air Quality Operating Permit Number AQ1086TVP01. Based on the attached calculations, MEA estimates the assessable emissions fee at $5,045.35.

If you have any questions regarding this submittal, please contact Traci Bradford by phone at 907-761-9374 or by email at traci.bradford@mea.coop.

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.

Sincerely,

Michael Mann
Plant Manager
Eklutna Generation Station

Enclosure: Assessable Emissions Estimate

cc: Tony Izzo, MEA
Tony Zellers, MEA
Traci Bradford, MEA
Jamie Brewer, SLR

Table A-1. Matanuska Electric Association - Eklutna Generation Station
FY 2020 Assessable Emissions Estimate

Pollutant	Assessable Potential to Emit[1]	CY 2018 Actual Emissions[2, 3]	Assessable Emissions[4]
Oxides of Nitrogen (NO_X)	188 tpy	43 tpy	43 tons
Carbon Monoxide (CO)	209 tpy	23 tpy	23 tons
Particulate Matter less than 10 micrometers in diameter (PM_{10})	221 tpy	12 tpy	12 tons
Volatile Organic Compounds (VOC)	157 tpy	29 tpy	29 tons
Sulfur Dioxide (SO_2)	21 tpy	10 tpy	10 tons
Total	**796 tpy**	**117 tpy**	**117 tons**

Assessable Emissions Fee[5] $ 5,045.35

Notes:

1. From Condition 40.1 of AQ1086TVP01 and Table C of the Statement of Basis for AQ1086TVP01.
2. Regulated air pollutant calculations are based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying emission tables.
3. Table A-2 provides a summary of 2018 actual operating hours by fuel type.
4. Fee not calculated for pollutant totals less than 10 tons.
5. Assessable emission fee is $42.95 per ton per 18 AAC 50.410(b)(1).

Table A-2. Matanuska Electric Association - Eklutna Generation Station
Emission Unit Inventory

Emission Unit			Fuel Type	Installation Date	CY 2018 Actual Operation	Maximum Capacity
ID	Description	Make/Model				
1	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	1,917 hr/yr	17.1 MW
2	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	7,208 hr/yr	17.1 MW
3	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	5,628 hr/yr	17.1 MW
4	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	3,427 hr/yr	17.1 MW
5	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	5,405 hr/yr	17.1 MW
6	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	5,398 hr/yr	17.1 MW
7	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	4,866 hr/yr	17.1 MW
8	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	3,655 hr/yr	17.1 MW
9	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	3,035 hr/yr	17.1 MW
10	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	2,563 hr/yr	17.1 MW
1-10 (combined)	Generator Engine	Wartsila 18V50DF	Diesel	N/A	226 hr/yr	17.1 MW (each)
11	Firewater Pump Engine	John Deere JU6H-UFADN0	Diesel	October 2014	25 hr/yr	197 hp
12	Black Start Generator Engine	Cummins 1000DQFAD	Diesel	April 2015	7.6 hr/yr	1,490 hp
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	NG	October 2014	2,304 hr/yr	15.75 MMBtu/hr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	NG	October 2014	1,785 hr/yr	15.75 MMBtu/hr
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	Diesel	October 2014	0.9 hr/yr	15.75 MMBtu/hr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	Diesel	October 2014	0.9 hr/yr	15.75 MMBtu/hr
15	Diesel Storage Tank	Rockford Corporation	Diesel	November 2014	8,760 hr/yr	509,000 gallons
16	Diesel Storage Tank	Rockford Corporation	Diesel	November 2014	8,760 hr/yr	509,000 gallons
17	Natural Gas Fuel Heater	DBA Aether C5-G30	NG	August 2017	8,760 hr/yr	8.3 MMBtu/hr
18	Black Start Generator Engine	Cummins 1000DQFAD	Diesel	April 2015	7 hr/yr	1,490 hp

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. An off-permit change notification was submitted on August 30, 2017 to inform ADEC that EU ID 17 is rated at 8.3 MMBtu/hr instead of 7.0 MMBtu/hr as initially permitted.

Table A-3. Matanuska Electric Association - Eklutna Generation Station
FY 2020 NO_X Emissions Calculations

Emission Unit			Fuel	Factor	NO_X Emission	CY 2018 Actual	CY 2018 Actual NO_X
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	1.61 lb/hr	1,917 hr/yr	1.5 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	1.85 lb/hr	7,208 hr/yr	6.7 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/16/17	1.15 lb/hr	5,628 hr/yr	3.2 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/21/17	1.56 lb/hr	3,427 hr/yr	2.7 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/18	1.2 lb/hr	5,405 hr/yr	3.2 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/18	1.2 lb/hr	5,398 hr/yr	3.2 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/17/17	1.30 lb/hr	4,866 hr/yr	3.2 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/17/17	1.32 lb/hr	3,655 hr/yr	2.4 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	1.09 lb/hr	3,035 hr/yr	1.7 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	1.47 lb/hr	2,563 hr/yr	1.9 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	19.95 lb/hr	226 hr/yr	2.3 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	2.7 g/hp-hr	25.3 hr/yr	1.5E-02 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	5.20 g/hp-hr	7.6 hr/yr	6.5E-02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	1.297 lb/hr	2,304 hr/yr	1.5 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	1.297 lb/hr	1,785 hr/yr	1.2 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	2.180 lb/hr	0.9 hr/yr	9.8E-04 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	2.180 lb/hr	0.9 hr/yr	9.8E-04 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.091 lb/MMBtu	8,760 hr/yr	3.3 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	5.20 g/hp-hr	7.4 hr/yr	6.3E-02 tpy
						Total CY 2018 Actual NO_X Emissions	**43.3 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Sample Calculations:
Emissions (tpy) = (Emission factor, lb/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, g/hp-hr) x (Rating, hp) x (Operation, hr/yr) / (Conversion, 453.59 g/lb) / (Conversion, 2,000 lb/ton)

Table A-4. Matanuska Electric Association - Eklutna Generation Station
FY 2020 CO Emissions Calculations

Emission Unit			Fuel	Factor	CO Emission	CY 2018 Actual	CY 2018 Actual CO
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	0.62 lb/hr	1,917 hr/yr	5.9E-01 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	0.93 lb/hr	7,208 hr/yr	3.4 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/16/17	0.61 lb/hr	5,628 hr/yr	1.7 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/21/17	0.87 lb/hr	3,427 hr/yr	1.5 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/18	0.93 lb/hr	5,405 hr/yr	2.5 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/18	0.96 lb/hr	5,398 hr/yr	2.6 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/17/17	0.82 lb/hr	4,866 hr/yr	2.0 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/17/17	0.76 lb/hr	3,655 hr/yr	1.4 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	0.84 lb/hr	3,035 hr/yr	1.3 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	0.58 lb/hr	2,563 hr/yr	7.4E-01 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	6.78 lb/hr	226 hr/yr	7.7E-01 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.9 g/hp-hr	25.3 hr/yr	4.9E-03 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.66 g/hp-hr	7.6 hr/yr	8.2E-03 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.575 lb/hr	2,304 hr/yr	6.6E-01 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.575 lb/hr	1,785 hr/yr	5.1E-01 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.564 lb/hr	0.9 hr/yr	2.5E-04 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.564 lb/hr	0.9 hr/yr	2.5E-04 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.037 lb/MMBtu	8,760 hr/yr	1.3 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.66 g/hp-hr	7.4 hr/yr	8.0E-03 tpy
Total CY 2018 Actual CO Emissions							**23.1 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Sample Calculations:
Emissions (tpy) = (Emission factor, lb/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, g/hp-hr) x (Rating, hp) x (Operation, hr/yr) / (Conversion, 453.59 g/lb) / (Conversion, 2,000 lb/ton)

Table A-5. Matanuska Electric Association - Eklutna Generation Station
FY 2020 PM_{10} Emissions Calculations

Emission Unit			Fuel	Factor	PM_{10} Emission	CY 2018 Actual	CY 2018 Actual PM_{10}
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	EU ID 10 Source Test 2/3/15	0.48 lb/hr	1,917 hr/yr	4.6E-01 tpy
2	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	7,208 hr/yr	1.7 tpy
3	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,628 hr/yr	1.4 tpy
4	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	3,427 hr/yr	8.2E-01 tpy
5	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,405 hr/yr	1.3 tpy
6	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,398 hr/yr	1.3 tpy
7	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	4,866 hr/yr	1.2 tpy
8	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	3,655 hr/yr	8.8E-01 tpy
9	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	3,035 hr/yr	7.3E-01 tpy
10	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	2,563 hr/yr	6.2E-01 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	10.92 lb/hr	226 hr/yr	1.2 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.1 g/hp-hr	25.3 hr/yr	5.5E-04 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.19 g/hp-hr	7.6 hr/yr	2.4E-03 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.095 lb/hr	2,304 hr/yr	1.1E-01 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.095 lb/hr	1,785 hr/yr	8.5E-02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.324 lb/hr	0.9 hr/yr	1.5E-04 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.324 lb/hr	0.9 hr/yr	1.5E-04 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.0048 lb/MMBtu	8,760 hr/yr	1.7E-01 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.19 g/hp-hr	7.4 hr/yr	2.3E-03 tpy
						Total CY 2018 Actual PM_{10} Emissions	**12.1 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Sample Calculations:
Emissions (tpy) = (Emission factor, lb/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, g/hp-hr) x (Rating, hp) x (Operation, hr/yr) / (Conversion, 453.59 g/lb) / (Conversion, 2,000 lb/ton)

Table A-6. Matanuska Electric Association - Eklutna Generation Station
FY 2020 VOC Emissions Calculations

Emission Unit			Fuel	Factor	VOC Emission	CY 2018 Actual	CY 2018 Actual VOC
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	1.02 lb/hr	1,917 hr/yr	1.0 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	1.53 lb/hr	7,208 hr/yr	5.5 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/16/17	1.24 lb/hr	5,628 hr/yr	3.5 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/21/17	1.23 lb/hr	3,427 hr/yr	2.1 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/2018	1.1 lb/hr	5,405 hr/yr	3.0 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/2018	1.3 lb/hr	5,398 hr/yr	3.5 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/17/17	1.21 lb/hr	4,866 hr/yr	2.9 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/17/17	1.51 lb/hr	3,655 hr/yr	2.8 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	1.54 lb/hr	3,035 hr/yr	2.3 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	1.11 lb/hr	2,563 hr/yr	1.4 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	7.91 lb/hr	226 hr/yr	8.9E-01 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.1 g/hp-hr	25.3 hr/yr	5.5E-04 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.12 g/hp-hr	7.6 hr/yr	1.5E-03 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.063 lb/hr	2,304 hr/yr	7.3E-02 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.063 lb/hr	1,785 hr/yr	5.6E-02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.062 lb/hr	0.9 hr/yr	2.8E-05 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.062 lb/hr	0.9 hr/yr	2.8E-05 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	See Table A-9	Not Applicable	8,760 hr/yr	1.0E-02 tpy
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	1.0E-02 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.003 lb/MMBtu	8,760 hr/yr	1.1E-01 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.12 g/hp-hr	7.4 hr/yr	1.5E-03 tpy
						Total CY 2018 Actual VOC Emissions	**28.9 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Sample Calculations:
Emissions (tpy) = (Emission factor, lb/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, g/hp-hr) x (Rating, hp) x (Operation, hr/yr) / (Conversion, 453.59 g/lb) / (Conversion, 2,000 lb/ton)

Table A-7. Matanuska Electric Association - Eklutna Generation Station
FY 2020 SO_2 Emissions Calculations

Emission Unit			Fuel	Factor	SO_2 Emission	CY 2018 Actual	CY 2018 Actual SO_2
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	1,917 hr/yr	4.4E-01 tpy
2	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	7,208 hr/yr	1.7 tpy
3	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,628 hr/yr	1.3 tpy
4	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	3,427 hr/yr	7.9E-01 tpy
5	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,405 hr/yr	1.2 tpy
6	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,398 hr/yr	1.2 tpy
7	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	4,866 hr/yr	1.1 tpy
8	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	3,655 hr/yr	0.8 tpy
9	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	3,035 hr/yr	7.0E-01 tpy
10	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	2,563 hr/yr	5.9E-01 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	ULSD	15 ppmw S	226 hr/yr	7.6E-02 tpy
11	Firewater Pump Engine	197 hp	Diesel	ULSD	15 ppmw S	25.3 hr/yr	2.7E-05 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	ULSD	15 ppmw S	7.6 hr/yr	5.7E-05 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	NG	20 ppmv H_2S	2,304 hr/yr	6.1E-02 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	NG	20 ppmv H_2S	1,785 hr/yr	4.7E-02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	ULSD	15 ppmw S	0.9 hr/yr	1.0E-05 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	ULSD	15 ppmw S	0.9 hr/yr	1.0E-05 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.0005 lb/MMBtu	8,760 hr/yr	1.8E-02 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	ULSD	15 ppmw S	7.4 hr/yr	5.5E-05 tpy
						Total CY 2018 Actual SO_2 Emissions	**10.1 tpy**

Notes:
1. NG is natural gas. ULSD is ultra-low sulfur diesel.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel. SO_2 emissions from diesel are included in the EU ID 1-10 combined diesel use emissions.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.
4. Conversions and Vendor Data:

EU IDs 1-10 natural gas (with 1% diesel) heat rate:	8,153 kJ/kW-hr (NG)	EU IDs 13 and 14 fuel consumption rate:	15,752 scf/hr
EU IDs 1-10 natural gas (with 1% diesel) fuel consumption rate:	2 g/kW-hr (diesel)	EU IDs 13 and 14 fuel consumption rate:	110.31 gal/hr
EU IDs 1-10 diesel fuel consumption rate:	204 g/kW-hr	Natural Gas Heat Content:	1,020 Btu/scf
EU ID 11 fuel consumption rate:	10.3 gal/hr	Standard Molar Volume:	359 scf/lb-mole
EU IDs 12 and 18 fuel consumption rate:	72.2 gal/hr	Diesel Heat Content:	138,000 Btu/gallon
Diesel Density:	6.9 lb/gallon	Energy Conversion:	1.055056 kJ/Btu
Mass Conversion:	453.6 g/lb		

Sample Calculations:
Emissions (tpy) = (H_2S Content, ppmv) / (Conversion, 1,000,000 parts) x (Rating, MW) x (Conversion, 1,000 kW/MW) x (Heat Rate, kJ/kW-hr) x (Operation, hr/yr) / (Natural Gas Heat Content, Btu/scf) / (Energy Conversion, kJ/Btu) / (Standard Molar Volume, scf/lb-mole) x (Molar Mass, lb H_2S/lb-mole H_2S) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Sulfur Content, ppmw) / (Conversion, 1,000,000 parts) x (Fuel Consumption, gal/hr) x (Operation, hr/yr) x (Diesel Density, lb/gal) x (Atomic Mass Conversion, Atomic Mass Product/Atomic Mass Reactant) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (H2S Content, ppmv) / (Conversion, 1,000,000 parts) / (Conversion, 379.9 scf/lb-mole) * (Molar Mass, lb H_2S/lb-mole H_2S) * (Operation, hr/yr) * (Fuel Consumption, scf/hr) / (Conversion 2000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)

Table A-8. Matanuska Electric Association - Eklutna Generation Station
FY 2020 Emissions Calculations - Wartsila 18V50DF Manufacturer Data

Engine Operation[1,2]							
Percent Load	100	75	50		100	75	50
Engine Output, kW	17,076	12,974	8,494		17,076	12,974	8,494
Inlet Temperature, °C	15.6	15.6	15.6		26.7	26.7	26.7
Natural Gas[3]							
Natural Gas Fuel Consumption, kJ/kW-hr	7,258	7,562	8,153		7,258	7,562	8,153
Diesel Fuel Consumption, g/kW-hr	1.0	1.5	2.4		1.0	1.5	2.4
Flue Gas Temperature, °C ±15°C	399	435	443		397	433	441
Flue Gas Flow, kg/s ±5%	27.6	21.3	15.9		27.6	21.3	15.9
Flue Gas Flow, Nm^3/s (Dry)	19.7	15.2	11.3		19.6	15.1	11.3
Flue Gas Flow, Nm^3/s (Wet)[4]	21.9	16.9	12.6		21.8	16.8	12.6
Flue Gas Flow, m^3/s (Actual)	51.0	41.4	31.1		50.6	41.0	31.1
Flue Gas Velocity, m/s	25.7	20.9	15.8		24.8	20.9	15.8
NO_X, ppmvd @ 15% O_2	6	9	9		6	9	9
NO_X, g/kW-hr	0.08	0.12	0.13		0.08	0.12	0.13
NO_X, lb/hr	3.01	3.43	2.43		3.01	3.43	2.43
CO, ppmvd @ 15% O_2	15	15	15		15	15	15
CO, g/kW-hr	0.12	0.12	0.13		0.12	0.12	0.13
CO, lb/hr	4.52	3.43	2.43		4.52	3.43	2.43
PM_{10}, mg/Nm^3 @ 15% O_2 (Dry)	20	25	30		20	25	30
PM_{10}, g/kW-hr	0.13	0.16	0.21		0.13	0.16	0.21
PM_{10}, lb/hr	4.89	4.58			4.89	4.58	3.93
VOC, ppmvd @ 15% O_2	20	25	25		20	25	25
VOC, g/kW-hr	0.09	0.12	0.13		0.09	0.12	0.13
VOC, lb/hr	3.39	3.43	2.43		3.39	3.43	2.43
CH_2O, ppmvd @ 15% O_2	0.70	NA	NA		0.70	NA	NA
CH_2O, lb/hr [6]	0.23	NA	NA		0.23	NA	NA
Diesel							
Fuel Consumption, g/kW-hr	189	192	204		189	192	204
Flue Gas Temperature, °C ±15°C	355	355	389		368	368	402
Flue Gas Flow, kg/s ±5%	34.5	27.4	18.9		33.3	26.4	18.3
Flue Gas Flow, Nm^3/s (Dry)	25.1	20	13.8		24.1	19.2	13.3
Flue Gas Flow, Nm^3/s (Wet)[5]	26.4	21.1	14.5		25.4	20.2	14.0
Flue Gas Flow, m^3/s (Actual)	57.5	45.8	33.3		56.3	44.9	32.7
Flue Gas Velocity, m/s	30.1	23.9	17.4		29.6	23.5	17.1
NO_X, ppmvd @ 15% O_2	35	40	40		35	40	40
NO_X, g/kW-hr	0.53	0.61	0.64		0.53	0.61	0.64
NO_X, lb/hr	19.95	17.45	11.98		19.95	17.45	11.98
CO, ppmvd @ 15% O_2	20	20	20		20	20	20
CO, g/kW-hr	0.18	0.19	0.19		0.18	0.19	0.19
CO, lb/hr	6.78	5.43	3.56		6.78	5.43	3.56
PM_{10}, mg/Nm^3 @ 15% O_2 (Dry)	40	50	60		40	50	60
PM_{10}, g/kW-hr	0.29	0.37	0.46		0.29	0.37	0.46
PM_{10}, lb/hr	10.92	10.58	8.61		10.92	10.58	8.61
VOC, ppmvd @ 15% O_2	40	40	40		40	40	40
VOC, g/kW-hr	0.21	0.21	0.22		0.21	0.21	0.22
VOC, lb/hr	7.91	6.01	4.12		7.91	6.01	4.12
CH_2O, ppmvd @ 15% O_2	0.70	NA	NA		0.70	NA	NA
CH_2O, lb/hr [7]	0.28	NA	NA		0.28	NA	NA

Table A-8. Matanuska Electric Association - Eklutna Generation Station
FY 2020 Emissions Calculations - Wartsila 18V50DF Manufacturer Data

Notes:
1. Values at 25 percent load are not provided, because this load is normally below manufacturer guaranteed stable operation.
2. Emission rates represent source test data measured after Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CATOX) emission control systems. SCR control efficiency is estimated at 93 to 94 percent. CATOX control efficiency is estimated at 93 to 94 percent for carbon monoxide and 70 percent for volatile organic compounds.
3. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
4. Normal flue gas flow for natural gas combustion assumes 10 percent moisture content. Actual pressure is conservatively estimated as standard pressure.
5. Normal flue gas flow for diesel combustion assumes 5 percent moisture content. Actual pressure is conservatively estimated as standard pressure.
6. Based on F_d factor of 8,710 for natural gas (40 CFR 60, Appendix A, Method 19).
7. Based on F_d factor of 9,190 for diesel (40 CFR 60, Appendix A, Method 19).

Table A-9. Matanuska Electric Association - Eklutna Generation Station
FY 2020 Emissions Calculations - Fuel Storage Tank Calculations

Fuel Storage Tank Detail	
Tank Identification	
Location:	Anchorage, AK
Orientation:	Vertical Fixed Roof
Contents:	Diesel
Tank Dimensions	
Capacity:	509,000 gallons
Diameter (D):	52 ft
Radius (R_S):	26 ft
Shell Height (H_S):	32 ft
Average Liquid Height (H_L):	20 ft
Maximum Liquid Height (H_{LX}):	30.0 ft
Diesel Throughput:	161,562 gal/yr
Paint Characteristics	
Paint Condition:	Good
Tank Color:	White
Roof Characteristics	
Type:	Cone
Slope (S_R):	0.06 ft/ft
Breather Vent Settings	
Vacuum Setting:	-0.03 psig
Pressure Setting:	0.03 psig

Standing Loss

Standing Loss (L_S) = $365 \times K_E \times (\pi / 4 \times D^2) \times H_{VO} \times K_S \times W_V$ (AP-42, Section 7.1, Equation 1-4)

$K_E = 0.0018 \times \Delta T_V = 0.0018 \times [0.72 \times (T_{AX} - T_{AN}) + 0.028 \times \alpha \times I]$ (AP-42, Section 7.1, Equation 1-5)

where:

T_{AX} = 43.6 °F (AP-42, Section 7.1, Table 7.1-7 for Homer AK)

T_{AN} = 29.5 °F (AP-42, Section 7.1, Table 7.1-7 for Homer AK)

T_{AX} = 503.6 °R

T_{AN} = 489.5 °R

α = 0.17 (dimensionless) (AP-42, Section 7.1, Table 7.1-6)

I = 838 Btu/ft^2-d (AP-42, Section 7.1, Table 7.1-7 for Homer AK)

K_E = 0.0255 (dimensionless)

$H_{vo} = H_S - H_L + H_{RO}$ (AP-42, Section 7.1, Equation 1-15)

where:

H_{RO}= (1/3) x H_R (AP-42, Section 7.1, Equation 1-16)

where:

$H_R = S_R \times R_S$ (AP-42, Section 7.1, Equation 1-17)

H_R= 1.56 ft

H_{RO}= 0.52 ft

H_{vo} = 12.5 ft

$K_S = 1 / (1 + 0.053 \times P_{va} \times H_{vo})$ (AP-42, Section 7.1, Equation 1-20)

where:

$T_{LA} = 0.44 \times T_{AA} + 0.56 \times T_B + 0.0079 \times \alpha \times I$ (AP-42, Section 7.1, Equation 1-26)

where:

$T_{AA} = (T_{AX} + T_{AN})/2$ (AP-42, Section 7.1, Equation 1-27)

T_{AA} = 496.55 °R

$T_B = T_{AA} + 6 \times \alpha - 1$ (AP-42, Section 7.1, Equation 1-28)

T_B = 496.57 °R

T_{LA} = 497.69 °R

P_{VA} = 0.0031 psi (AP-42, Section 7.1, Table 7.1-2)

K_S = 0.99795 (dimensionless)

$W_V = (M_V \times P_{VA}) / (10.731 \times T_{LA})$ (AP-42, Section 7.1, Equation 1-21)

where:

M_V = 130 lb/lb-mole (AP-42, Section 7.1, Table 7.1-2)

W_v = 7.55E-05 lb/ft^3

L_s = 18.60 lb/yr

Working Loss	
Working Loss (L_W) = $0.0010 / 5.614 \times 10.731 \times T_{LA} \times N \times H_{LX} \times (\pi / 4 \times D^2) \times K_N \times K_P \times W_V$	(AP-42, Section 7.1, Equation 1-34)
$N = 5.614 \times Q / V_{LX}$	(AP-42, Section 7.1, Equation 1-30)
where:	
Q = 3,847 bbl/yr	(Throughput converted from gal/yr to bbl/yr)
$V_{LX} = \pi / 4 \times D^2 \times H_{LX}$	(AP-42, Section 7.1, Equation 1-31)
V_{LX} = 63,711 ft^3	
N = 0.3 (dimensionless)	
K_N = 1 (dimensionless)	
K_p = 1 (dimensionless)	(AP-42, Section 7.1, Notes under Equation 1-35)
L_w= 1.65 lb/yr	
Total Loss	
Total Loss (L_T) = $L_s + L_w$	(AP-42, Section 7.1, Equation 1-1)
L_T = 20.26 lb/yr	

MATANUSKA ELECTRIC ASSOCIATION

March 19, 2020

CERTIFIED MAIL 7016 3010 0000 6810 7206
Return Receipt Requested

Alaska Department of Environmental Conservation
Air Permits Program
ATTN: Assessable Emissions Estimate
410 Willoughby Avenue
P.O. Box 111800
Juneau, AK 99811-1800

Subject: FY 2021 Assessable Emissions Estimate
Matanuska Electric Association – Eklutna Generation Station
Air Quality Operating Permit No. AQ1086TVP01

To Whom It May Concern,

Matanuska Electric Association (MEA) is submitting the enclosed fiscal year (FY) 2021 assessable emissions estimate for the Eklutna Generation Station in accordance with Condition 41.1 of Air Quality Operating Permit Number AQ1086TVP01. Based on the attached calculations, MEA estimates the assessable emissions fee at $5,912.60.

If you have any questions regarding this submittal, please contact Traci Bradford by phone at 907-761-9374 or by email at traci.bradford@mea.coop.

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.

Sincerely,

Michael Mann
Plant Manager
Eklutna Generation Station

Enclosure: Assessable Emissions Estimate

cc: Tony Izzo, MEA
Tony Zellers, MEA
Traci Bradford, MEA
Jeanette Brena, SLR

Table A-1. Matanuska Electric Association - Eklutna Generation Station
FY 2021 Assessable Emissions Estimate

Pollutant	Assessable Potential to Emit[1]	CY 2019 Actual Emissions[2, 3]	Assessable Emissions[4]
Oxides of Nitrogen (NO_X)	188 tpy	46 tpy	46 tons
Carbon Monoxide (CO)	209 tpy	30 tpy	30 tons
Particulate Matter less than 10 micrometers in diameter (PM_{10})	221 tpy	14 tpy	14 tons
Volatile Organic Compounds (VOC)	157 tpy	36 tpy	36 tons
Sulfur Dioxide (SO_2)	21 tpy	12 tpy	12 tons
Total	**796 tpy**	**138 tpy**	**138 tons**

Assessable Emissions Fee[5] $ 5,912.60

Notes:

1. From Condition 40.1 of AQ1086TVP01 and Table C of the Statement of Basis for AQ1086TVP01.
2. Regulated air pollutant calculations are based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying emission tables.
3. Table A-2 provides a summary of 2019 actual operating hours by fuel type.
4. Fee not calculated for pollutant totals less than 10 tons.
5. Assessable emission fee is $42.95 per ton per 18 AAC 50.410(b)(1).

Table A-2. Matanuska Electric Association - Eklutna Generation Station
Emission Unit Inventory

Emission Unit			Fuel Type	Installation Date	CY 2019 Actual Operation	Maximum Capacity
ID	Description	Make/Model				
1	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	4,727 hr/yr	17.1 MW
2	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	5,323 hr/yr	17.1 MW
3	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	5,191 hr/yr	17.1 MW
4	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	4,926 hr/yr	17.1 MW
5	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	5,054 hr/yr	17.1 MW
6	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	6,155 hr/yr	17.1 MW
7	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	5,296 hr/yr	17.1 MW
8	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	5,251 hr/yr	17.1 MW
9	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	5,162 hr/yr	17.1 MW
10	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	5,560 hr/yr	17.1 MW
1-10 (combined)	Generator Engine	Wartsila 18V50DF	Diesel	N/A	212 hr/yr	17.1 MW (each)
11	Firewater Pump Engine	John Deere JU6H-UFADN0	Diesel	October 2014	26 hr/yr	197 hp
12	Black Start Generator Engine	Cummins 1000DQFAD	Diesel	April 2015	6.3 hr/yr	1,490 hp
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	NG	October 2014	1,827 hr/yr	15.75 MMBtu/hr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	NG	October 2014	1,387 hr/yr	15.75 MMBtu/hr
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	Diesel	October 2014	0.0 hr/yr	15.75 MMBtu/hr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	Diesel	October 2014	0.0 hr/yr	15.75 MMBtu/hr
15	Diesel Storage Tank	Rockford Corporation	Diesel	November 2014	8,760 hr/yr	509,000 gallons
16	Diesel Storage Tank	Rockford Corporation	Diesel	November 2014	8,760 hr/yr	509,000 gallons
17	Natural Gas Fuel Heater	DBA Aether C5-G30	NG	August 2017	8,760 hr/yr	8.3 MMBtu/hr
18	Black Start Generator Engine	Cummins 1000DQFAD	Diesel	April 2015	6.2 hr/yr	1,490 hp

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. An off-permit change notification was submitted on August 30, 2017 to inform ADEC that EU ID 17 is rated at 8.3 MMBtu/hr instead of 7.0 MMBtu/hr as initially permitted.

Table A-3. Matanuska Electric Association - Eklutna Generation Station
FY 2021 NO_X Emissions Calculations

Emission Unit			Fuel	Factor	NO_X Emission	CY 2019 Actual	CY 2019 Actual NO_X
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	1.61 lb/hr	4,727 hr/yr	3.8 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	1.85 lb/hr	5,323 hr/yr	4.9 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/16/17	1.15 lb/hr	5,191 hr/yr	3.0 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/21/17	1.56 lb/hr	4,926 hr/yr	3.8 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/18	1.2 lb/hr	5,054 hr/yr	3.0 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/18	1.2 lb/hr	6,155 hr/yr	3.7 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/25/19	0.87 lb/hr	5,296 hr/yr	2.3 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/25/19	0.71 lb/hr	5,251 hr/yr	1.9 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	1.09 lb/hr	5,162 hr/yr	2.8 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	1.47 lb/hr	5,560 hr/yr	4.1 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	19.95 lb/hr	212 hr/yr	2.1 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	2.7 g/hp-hr	26 hr/yr	1.5E-02 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	5.20 g/hp-hr	6.3 hr/yr	5.4E-02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	1.297 lb/hr	1,827 hr/yr	1.2 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	1.297 lb/hr	1,387 hr/yr	0.9 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	2.180 lb/hr	0.0 hr/yr	0.0E+00 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	2.180 lb/hr	0.0 hr/yr	0.0E+00 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.091 lb/MMBtu	8,760 hr/yr	3.3 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	5.20 g/hp-hr	6.2 hr/yr	5.3E-02 tpy
						Total CY 2019 Actual NO_X Emissions	45.6 tpy

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Sample Calculations:
Emissions (tpy) = (Emission factor, lb/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, g/hp-hr) x (Rating, hp) x (Operation, hr/yr) / (Conversion, 453.59 g/lb) / (Conversion, 2,000 lb/ton)

Table A-4. Matanuska Electric Association - Eklutna Generation Station
FY 2021 CO Emissions Calculations

Emission Unit			Fuel	Factor	CO Emission	CY 2019 Actual	CY 2019 Actual CO
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	0.62 lb/hr	4,727 hr/yr	1.5E+00 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	0.93 lb/hr	5,323 hr/yr	2.5 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/16/17	0.61 lb/hr	5,191 hr/yr	1.6 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/21/17	0.87 lb/hr	4,926 hr/yr	2.1 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/18	0.93 lb/hr	5,054 hr/yr	2.4 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/18	0.96 lb/hr	6,155 hr/yr	3.0 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/25/19	1.41 lb/hr	5,296 hr/yr	3.7 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/25/19	1.67 lb/hr	5,251 hr/yr	4.4 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	0.84 lb/hr	5,162 hr/yr	2.2 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	0.58 lb/hr	5,560 hr/yr	1.6E+00 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	6.78 lb/hr	212 hr/yr	7.2E-01 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.9 g/hp-hr	26 hr/yr	5.1E-03 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.66 g/hp-hr	6.3 hr/yr	6.8E-03 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.575 lb/hr	1,827 hr/yr	5.3E-01 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.575 lb/hr	1,387 hr/yr	4.0E-01 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.564 lb/hr	0.0 hr/yr	0.0E+00 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.564 lb/hr	0.0 hr/yr	0.0E+00 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.037 lb/MMBtu	8,760 hr/yr	1.3 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.66 g/hp-hr	6.2 hr/yr	6.7E-03 tpy
Total CY 2019 Actual CO Emissions							**29.6 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Sample Calculations:
Emissions (tpy) = (Emission factor, lb/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, g/hp-hr) x (Rating, hp) x (Operation, hr/yr) / (Conversion, 453.59 g/lb) / (Conversion, 2,000 lb/ton)

Table A-5. Matanuska Electric Association - Eklutna Generation Station
FY 2021 PM_{10} Emissions Calculations

Emission Unit			Fuel	Factor	PM_{10} Emission	CY 2019 Actual	CY 2019 Actual PM_{10}
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	EU ID 10 Source Test 2/3/15	0.48 lb/hr	4,727 hr/yr	1.1E+00 tpy
2	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,323 hr/yr	1.3 tpy
3	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,191 hr/yr	1.2 tpy
4	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	4,926 hr/yr	1.2E+00 tpy
5	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,054 hr/yr	1.2 tpy
6	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	6,155 hr/yr	1.5 tpy
7	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,296 hr/yr	1.3 tpy
8	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,251 hr/yr	1.3E+00 tpy
9	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,162 hr/yr	1.2E+00 tpy
10	Generator Engine	17.1 MW	NG/Diesel		0.48 lb/hr	5,560 hr/yr	1.3E+00 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	10.92 lb/hr	212 hr/yr	1.2 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.1 g/hp-hr	26.0 hr/yr	5.6E-04 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.19 g/hp-hr	6.3 hr/yr	2.0E-03 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.095 lb/hr	1,827 hr/yr	8.7E-02 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.095 lb/hr	1,387 hr/yr	6.6E-02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.324 lb/hr	- hr/yr	0.0E+00 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.324 lb/hr	- hr/yr	0.0E+00 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.0048 lb/MMBtu	8,760 hr/yr	1.7E-01 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.19 g/hp-hr	6.2 hr/yr	1.9E-03 tpy
						Total CY 2019 Actual PM_{10} Emissions	**14.2 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Sample Calculations:
Emissions (tpy) = (Emission factor, lb/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, g/hp-hr) x (Rating, hp) x (Operation, hr/yr) / (Conversion, 453.59 g/lb) / (Conversion, 2,000 lb/ton)

Table A-6. Matanuska Electric Association - Eklutna Generation Station
FY 2021 VOC Emissions Calculations

Emission Unit			Fuel	Factor	VOC Emission	CY 2019 Actual	CY 2019 Actual VOC
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	1.02 lb/hr	4,727 hr/yr	2.4 tpy
2	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/15/17	1.53 lb/hr	5,323 hr/yr	4.1 tpy
3	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/16/17	1.24 lb/hr	5,191 hr/yr	3.2 tpy
4	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/21/17	1.23 lb/hr	4,926 hr/yr	3.0 tpy
5	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/2018	1.1 lb/hr	5,054 hr/yr	2.8 tpy
6	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/5/2018	1.3 lb/hr	6,155 hr/yr	4.0 tpy
7	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/25/19	1.55 lb/hr	5,296 hr/yr	4.1 tpy
8	Generator Engine	17.1 MW	NG/Diesel	Source Test 6/25/19	1.79 lb/hr	5,251 hr/yr	4.7 tpy
9	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	1.54 lb/hr	5,162 hr/yr	4.0 tpy
10	Generator Engine	17.1 MW	NG/Diesel	Source Test 3/20/17	1.11 lb/hr	5,560 hr/yr	3.1 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table A-8	7.91 lb/hr	212 hr/yr	8.4E-01 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.1 g/hp-hr	26.0 hr/yr	5.6E-04 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.12 g/hp-hr	6.3 hr/yr	1.2E-03 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.063 lb/hr	1,827 hr/yr	5.8E-02 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.063 lb/hr	1,387 hr/yr	4.4E-02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.062 lb/hr	- hr/yr	0.0E+00 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.062 lb/hr	- hr/yr	0.0E+00 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	See Table A-9	Not Applicable	8,760 hr/yr	1.0E-02 tpy
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	1.0E-02 tpy
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.003 lb/MMBtu	8,760 hr/yr	1.1E-01 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.12 g/hp-hr	6.2 hr/yr	1.2E-03 tpy
						Total CY 2019 Actual VOC Emissions	**36.0 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Sample Calculations:
Emissions (tpy) = (Emission factor, lb/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)
Emissions (tpy) = (Emission factor, g/hp-hr) x (Rating, hp) x (Operation, hr/yr) / (Conversion, 453.59 g/lb) / (Conversion, 2,000 lb/ton)

Table A-7. Matanuska Electric Association - Eklutna Generation Station
FY 2021 SO_2 Emissions Calculations

Emission Unit			Fuel	Factor	SO_2 Emission	CY 2019 Actual	CY 2019 Actual SO_2
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	4,727 hr/yr	1.1E+00 tpy
2	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,323 hr/yr	1.2 tpy
3	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,191 hr/yr	1.2 tpy
4	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	4,926 hr/yr	1.1E+00 tpy
5	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,054 hr/yr	1.2 tpy
6	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	6,155 hr/yr	1.4 tpy
7	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,296 hr/yr	1.2 tpy
8	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,251 hr/yr	1.2 tpy
9	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,162 hr/yr	1.2E+00 tpy
10	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	5,560 hr/yr	1.3E+00 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	ULSD	15 ppmw S	212 hr/yr	8.5E-02 tpy
11	Firewater Pump Engine	197 hp	Diesel	ULSD	15 ppmw S	26.0 hr/yr	2.8E-05 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	ULSD	15 ppmw S	6.3 hr/yr	4.7E-05 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	NG	20 ppmv H_2S	1,827 hr/yr	4.8E-02 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	NG	20 ppmv H_2S	1,387 hr/yr	3.7E-02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	ULSD	15 ppmw S	0.0 hr/yr	0.0E+00 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	ULSD	15 ppmw S	0.0 hr/yr	0.0E+00 tpy
15	Diesel Storage Tank	509,000 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	509,000 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	8.3 MMBtu/hr	NG	Manufacturer Data	0.0005 lb/MMBtu	8,760 hr/yr	1.8E-02 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	ULSD	15 ppmw S	6.2 hr/yr	4.6E-05 tpy
						Total CY 2019 Actual SO_2 Emissions	12.3 tpy

Notes:

1. NG is natural gas. ULSD is ultra-low sulfur diesel.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel. SO_2 emissions from diesel are included in the EU ID 1-10 combined diesel use emissions.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.
4. Conversions and Vendor Data:

EU IDs 1-10 natural gas (with 1% diesel) heat rate:	8,153 kJ/kW-hr (NG)	EU IDs 13 and 14 fuel consumption rate:	15,752 scf/hr
EU IDs 1-10 natural gas (with 1% diesel) fuel consumption rate:	2 g/kW-hr (diesel)	EU IDs 13 and 14 fuel consumption rate:	110.31 gal/hr
EU IDs 1-10 diesel fuel consumption rate:	204 g/kW-hr	Natural Gas Heat Content:	1,020 Btu/scf
EU ID 11 fuel consumption rate:	10.3 gal/hr	Standard Molar Volume:	359 scf/lb-mole
EU IDs 12 and 18 fuel consumption rate:	72.2 gal/hr	Diesel Heat Content:	138,000 Btu/gallon
Diesel Density:	6.9 lb/gallon	Energy Conversion:	1.055056 kJ/Btu
Mass Conversion:	453.6 g/lb		

Sample Calculations:

Emissions (tpy) = (H_2S Content, ppmv) / (Conversion, 1,000,000 parts) x (Rating, MW) x (Conversion, 1,000 kW/MW) x (Heat Rate, kJ/kW-hr) x (Operation, hr/yr) / (Natural Gas Heat Content, Btu/scf) / (Energy Conversion, kJ/Btu) / (Standard Molar Volume, scf/lb-mole) x (Molar Mass, lb H_2S/lb-mole H_2S) / (Conversion, 2,000 lb/ton)

Emissions (tpy) = (Sulfur Content, ppmw) / (Conversion, 1,000,000 parts) x (Fuel Consumption, gal/hr) x (Operation, hr/yr) x (Diesel Density, lb/gal) x (Atomic Mass Conversion, Atomic Mass Product/Atomic Mass Reactant) / (Conversion, 2,000 lb/ton)

Emissions (tpy) = (H2S Content, ppmv) / (Conversion, 1,000,000 parts) / (Conversion, 379.9 scf/lb-mole) * (Molar Mass, lb H_2S/lb-mole H_2S) * (Operation, hr/yr) * (Fuel Consumption, scf/hr) / (Conversion 2000 lb/ton)

Emissions (tpy) = (Emission factor, lb/MMBtu) x (Rating, MMBtu/hr) x (Operation, hr/yr) / (Conversion, 2,000 lb/ton)

Table A-8. Matanuska Electric Association - Eklutna Generation Station
FY 2021 Emissions Calculations - Wartsila 18V50DF Manufacturer Data

Engine Operation[1,2]							
Percent Load	100	75	50		100	75	50
Engine Output, kW	17,076	12,974	8,494		17,076	12,974	8,494
Inlet Temperature, °C	15.6	15.6	15.6		26.7	26.7	26.7
Natural Gas[3]							
Natural Gas Fuel Consumption, kJ/kW-hr	7,258	7,562	8,153		7,258	7,562	8,153
Diesel Fuel Consumption, g/kW-hr	1.0	1.5	2.4		1.0	1.5	2.4
Flue Gas Temperature, °C ±15°C	399	435	443		397	433	441
Flue Gas Flow, kg/s ±5%	27.6	21.3	15.9		27.6	21.3	15.9
Flue Gas Flow, Nm^3/s (Dry)	19.7	15.2	11.3		19.6	15.1	11.3
Flue Gas Flow, Nm^3/s (Wet)[4]	21.9	16.9	12.6		21.8	16.8	12.6
Flue Gas Flow, m^3/s (Actual)	51.0	41.4	31.1		50.6	41.0	31.1
Flue Gas Velocity, m/s	25.7	20.9	15.8		24.8	20.9	15.8
NO_X, ppmvd @ 15% O_2	6	9	9		6	9	9
NO_X, g/kW-hr	0.08	0.12	0.13		0.08	0.12	0.13
NO_X, lb/hr	3.01	3.43	2.43		3.01	3.43	2.43
CO, ppmvd @ 15% O_2	15	15	15		15	15	15
CO, g/kW-hr	0.12	0.12	0.13		0.12	0.12	0.13
CO, lb/hr	4.52	3.43	2.43		4.52	3.43	2.43
PM_{10}, mg/Nm^3 @ 15% O_2 (Dry)	20	25	30		20	25	30
PM_{10}, g/kW-hr	0.13	0.16	0.21		0.13	0.16	0.21
PM_{10}, lb/hr	4.89	4.58			4.89	4.58	3.93
VOC, ppmvd @ 15% O_2	20	25	25		20	25	25
VOC, g/kW-hr	0.09	0.12	0.13		0.09	0.12	0.13
VOC, lb/hr	3.39	3.43	2.43		3.39	3.43	2.43
CH_2O, ppmvd @ 15% O_2	0.70	NA	NA		0.70	NA	NA
CH_2O, lb/hr[6]	0.23	NA	NA		0.23	NA	NA
Diesel							
Fuel Consumption, g/kW-hr	189	192	204		189	192	204
Flue Gas Temperature, °C ±15°C	355	355	389		368	368	402
Flue Gas Flow, kg/s ±5%	34.5	27.4	18.9		33.3	26.4	18.3
Flue Gas Flow, Nm^3/s (Dry)	25.1	20	13.8		24.1	19.2	13.3
Flue Gas Flow, Nm^3/s (Wet)[5]	26.4	21.1	14.5		25.4	20.2	14.0
Flue Gas Flow, m^3/s (Actual)	57.5	45.8	33.3		56.3	44.9	32.7
Flue Gas Velocity, m/s	30.1	23.9	17.4		29.6	23.5	17.1
NO_X, ppmvd @ 15% O_2	35	40	40		35	40	40
NO_X, g/kW-hr	0.53	0.61	0.64		0.53	0.61	0.64
NO_X, lb/hr	19.95	17.45	11.98		19.95	17.45	11.98
CO, ppmvd @ 15% O_2	20	20	20		20	20	20
CO, g/kW-hr	0.18	0.19	0.19		0.18	0.19	0.19
CO, lb/hr	6.78	5.43	3.56		6.78	5.43	3.56
PM_{10}, mg/Nm^3 @ 15% O_2 (Dry)	40	50	60		40	50	60
PM_{10}, g/kW-hr	0.29	0.37	0.46		0.29	0.37	0.46
PM_{10}, lb/hr	10.92	10.58	8.61		10.92	10.58	8.61
VOC, ppmvd @ 15% O_2	40	40	40		40	40	40
VOC, g/kW-hr	0.21	0.21	0.22		0.21	0.21	0.22
VOC, lb/hr	7.91	6.01	4.12		7.91	6.01	4.12
CH_2O, ppmvd @ 15% O_2	0.70	NA	NA		0.70	NA	NA
CH_2O, lb/hr[7]	0.28	NA	NA		0.28	NA	NA

Table A-8. Matanuska Electric Association - Eklutna Generation Station
FY 2021 Emissions Calculations - Wartsila 18V50DF Manufacturer Data

Notes:

1. Values at 25 percent load are not provided, because this load is normally below manufacturer guaranteed stable operation.
2. Emission rates represent source test data measured after Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CATOX) emission control systems. SCR control efficiency is estimated at 93 to 94 percent. CATOX control efficiency is estimated at 93 to 94 percent for carbon monoxide and 70 percent for volatile organic compounds.
3. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
4. Normal flue gas flow for natural gas combustion assumes 10 percent moisture content. Actual pressure is conservatively estimated as standard pressure.
5. Normal flue gas flow for diesel combustion assumes 5 percent moisture content. Actual pressure is conservatively estimated as standard pressure.
6. Based on F_d factor of 8,710 for natural gas (40 CFR 60, Appendix A, Method 19).
7. Based on F_d factor of 9,190 for diesel (40 CFR 60, Appendix A, Method 19).

Table A-9. Matanuska Electric Association - Eklutna Generation Station
FY 2021 Emissions Calculations - Fuel Storage Tank Calculations

Fuel Storage Tank Detail

Tank Identification	
Location:	Anchorage, AK
Orientation:	Vertical Fixed Roof
Contents:	Diesel
Tank Dimensions	
Capacity:	509,000 gallons
Diameter (D):	52 ft
Radius (R_S):	26 ft
Shell Height (H_S):	32 ft
Average Liquid Height (H_L):	20 ft
Maximum Liquid Height (H_{LX}):	30.0 ft
Diesel Throughput:	161,562 gal/yr
Paint Characteristics	
Paint Condition:	Good
Tank Color:	White
Roof Characteristics	
Type:	Cone
Slope (S_R):	0.06 ft/ft
Breather Vent Settings	
Vacuum Setting:	-0.03 psig
Pressure Setting:	0.03 psig

Standing Loss

Standing Loss (L_S) = $365 \times K_E \times (\pi / 4 \times D^2) \times H_{VO} \times K_S \times W_V$ (AP-42, Section 7.1, Equation 1-4)

$K_E = 0.0018 \times \Delta T_V = 0.0018 \times [0.72 \times (T_{AX} - T_{AN}) + 0.028 \times \alpha \times I]$ (AP-42, Section 7.1, Equation 1-5)

where:

T_{AX} = 43.6 °F (AP-42, Section 7.1, Table 7.1-7 for Homer AK)

T_{AN} = 29.5 °F (AP-42, Section 7.1, Table 7.1-7 for Homer AK)

T_{AX} = 503.6 °R

T_{AN} = 489.5 °R

α = 0.17 (dimensionless) (AP-42, Section 7.1, Table 7.1-6)

I = 838 Btu/ft^2-d (AP-42, Section 7.1, Table 7.1-7 for Homer AK)

K_E = 0.0255 (dimensionless)

$H_{vo} = H_S - H_L + H_{RO}$ (AP-42, Section 7.1, Equation 1-15)

where:

$H_{RO} = (1/3) \times H_R$ (AP-42, Section 7.1, Equation 1-16)

where:

$H_R = S_R \times R_S$ (AP-42, Section 7.1, Equation 1-17)

H_R = 1.56 ft

H_{RO} = 0.52 ft

H_{vo} = 12.5 ft

$K_S = 1 / (1 + 0.053 \times P_{va} \times H_{vo})$ (AP-42, Section 7.1, Equation 1-20)

where:

$T_{LA} = 0.44 \times T_{AA} + 0.56 \times T_B + 0.0079 \times \alpha \times I$ (AP-42, Section 7.1, Equation 1-26)

where:

$T_{AA} = (T_{AX} + T_{AN})/2$ (AP-42, Section 7.1, Equation 1-27)

T_{AA} = 496.55 °R

$T_B = T_{AA} + 6 \times \alpha - 1$ (AP-42, Section 7.1, Equation 1-28)

T_B = 496.57 °R

T_{LA} = 497.69 °R

P_{VA} = 0.0031 psi (AP-42, Section 7.1, Table 7.1-2)

K_S = 0.99795 (dimensionless)

$W_V = (M_V \times P_{VA}) / (10.731 \times T_{LA})$ (AP-42, Section 7.1, Equation 1-21)

where:

M_V = 130 lb/lb-mole (AP-42, Section 7.1, Table 7.1-2)

W_v = 7.55E-05 lb/ft^3

L_s = 18.60 lb/yr

Working Loss			
Working Loss (L_W) =	$0.0010 / 5.614 \times 10.731 \times T_{LA} \times N \times H_{LX} \times (\pi / 4 \times D^2) \times K_N \times K_P \times W_V$		(AP-42, Section 7.1, Equation 1-34)
	$N = 5.614 \times Q / V_{LX}$		(AP-42, Section 7.1, Equation 1-30)
	where:		
	Q =	3,847 bbl/yr	(Throughput converted from gal/yr to bbl/yr)
	$V_{LX} = \pi / 4 \times D^2 \times H_{LX}$		(AP-42, Section 7.1, Equation 1-31)
	V_{LX} =	63,711 ft^3	
	N =	0.3 (dimensionless)	
	K_N =	1 (dimensionless)	
	K_p =	1 (dimensionless)	(AP-42, Section 7.1, Notes under Equation 1-35)
L_w=	1.65 lb/yr		

Total Loss		
Total Loss (L_T) = $L_s + L_w$		(AP-42, Section 7.1, Equation 1-1)
L_T =	20.26 lb/yr	

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P.O. Box 2929 • Palmer, Alaska 99645
907.761.9300

Received
MAR 23 2020
JNU SOA/DEC/DAS

Alaska Department of Environmental Conservation
Air Permits Program
ATTN: Assessable Emissions Estimate
410 Willoughby Avenue
P.O. Box 111800
Juneau, AK 99811-1800

DOYON UTILITIES LLC

714 Fourth Avenue, Suite 100 • Fairbanks, AK 99701
PO Box 74040 • Fairbanks, AK 99707
Phone (907) 455-1500 • Fax (907) 455-6788

August 25, 2021

Sent via email to:
Jentgen.matthew@epa.gov

Environmental Protection Agency
Matthew Jentgen
U.S. Environmental Protection Agency Region 10
1200 Sixth Avenue, Suite 155
Seattle, Washington 98101

RE: Revised Wainwright BACT SO_2 Emission Control Study

Dear Mr. Jentgen,

Doyon Utilities (DU) completed a revised sulfur dioxide (SO_2) emission study on its Fort Wainwright Central Heat and Power Plant (FWA CHPP). The study adopts and applies the five-step Best Available Control Technology (BACT) analysis, considers cost and safety concerns along with collateral environmental impacts, and concludes that the only cost-effective BACT solution for the FWA CHPP is the installation of a Dry Sorbent Injection (DSI) system to address the presumptive emissions control level of 0.12 lb SO_2/MMBtu. The study confirms ADEC's determination that DSI is BACT for reducing SO_2 emissions from [redacted] boilers at the FWA CHPP.

DU submitted its draft SO_2 study to the EPA on May 27, 2021. DU received EPA's comments on the draft on June 17, 2021. DU's Contractor, Black & Veatch, undertook additional research and made significant revisions to address EPA's comments. EPA's comments are attached hereto for easy reference.

The cost-effectiveness of all technically feasible emission control options is presented in Section 5.2.1. After considering the base costs of all five control technologies and the likely economic impact of mitigating environmental effects of implementation, the DSI system is the only cost-effective technology and therefore the only economically feasible control technology. Collateral environmental impacts for wet systems, if considered, give rise to safety concerns for the facility and the surrounding community due to ice fog events. Wet systems contribute to a 53-percent increase in flue gas moisture content. Ice fog has directly contributed to accidents on the neighboring highway and a crashed plane at the nearby airfield. Mitigation efforts, if feasible, would make these wet control technologies more costly, further increasing the cost per ton of SO_2 removed and reinforcing that these technologies as not cost-effective. In addition, wet systems would generate a 31 percent increase to the current FWA CHPP wastewater flow and would burden the local (and only) wastewater treatment plant. Additional technologies would require research and manage the increase wastewater flow and sulfide concentrations.

DSI is the only cost-effective option by a large margin and poses no additional safety risks towards ice fog events or considerable management of waste byproducts. DU believes that we have presented sufficient information to raise the concern that if a wet scrubber was installed, it would create [redacted] environmental collateral impact [redacted]

Please advise if you have any questions or concerns.

Sincerely,

Shayne Coiley
Senior Vice President
Doyon Utilities, LLC

Attachment: 25 August 2021 Wainwright SO_2 Emission Control Study
Doyon Utilities Response to EPA 17 June 2021 Comments

cc:
S. Kimble, Contracting Officer DLA
R. Paxton, Contract Specialist, DLA Energy
J. Meyer, Operations and Maintenance Chief, FWA Garrison
F. Sandgren, COR, FWA Garrison
P. Marvin, Utilities Chief, FWA Garrison
E. Dick, FWA Garrison
L. Florence, President, Doyon Utilities
E. Stevenson, Vice President of Operations, DU
K. Hook, Director of Environment, DU
T. Howard, Director of Engineering Project Devpmnt, DU
Z. Hedgpeth, EPA
L. Sorrels, EPA
A. Edwards, ADEC
C. Heil, ADEC
J. Plosay, ADEC
A. Simpson, ADEC

Doyon Utilities (DU) has responded to each of the EPA's specific cost analysis comments, numbered 1-12 below. A brief summary of DU's position and supporting information is provided along with the location of the full response in the revised report.

EPA Cost Analysis Comments:

1) EPA Comment: Greater O&M Staffing Hours

The Doyon cost analysis includes between 6 and 10 full-time operators plus an equal number of full- time maintenance staff dedicated to the various SO_2 control devices. Only operation and maintenance costs necessary for the additional control equipment under analysis may be included. The EPA Cost Manual default value for necessary labor for the various SO2 control devices attributes 0.5 hours per 8-hour shift each for operation and maintenance. This default value was recently reviewed and underwent public comment as part of the release of the new wet and dry scrubbers chapter in the EPA Cost Manual and found in Table 1.9 of that chapter. Higher labor rates cited in the chapter originate in the U.S. The EPA Integrated Planning Model that is applicable to much larger units than those operated at Fort Wainwright.

DU's Response: See Section 2.2.2 – Operating Labor Costs

Experience and research does not agree with the EPA's position that only 0.5 hours per 8 hour shift is required for operations and maintenance. To confirm the manpower requirements, Black & Veatch reached out to several clients that own and operate FGD systems. Three clients responded, all of which say that well more than 0.5 hours per 8-hour shift are required. This agrees with pages 1-34 and 1-54 of the updated EPA Cost Control Manual (CCM) for Wet and Dry Scrubbers for Acid Gas Control: "…[A WFGD requires] 12 additional full-time personnel for units equal to or less than 500 MW," and, "generally, eight additional full-time personnel are required to operate an SDA FGD system."

The final cost analysis plans for eight full-time employees to operate a limestone-WFGD and six full-time employees for a caustic-WFGD, CDS, or SDA.

2) EPA Comment: Use of Capital Cost Factors not from CCM

The Doyon cost analysis uses much higher capital cost factors in a number of instances in place of the EPA Cost Manual default cost factors that are discussed in Section 5, Chapter 1 of the Manual. For example, the Doyon cost analysis assumes erection cost will be [redacted] percent of the purchased equipment cost, while the EPA Cost Manual default value is 40 percent. These cost factors result in construction/installation and indirect capital costs that are much higher as a proportion of PEC than other recent cost analysis projects the EPA has reviewed in Alaska, including the prior cost analyses submitted as part of the Fairbanks SIP. The specific basis for each of these increased cost factors with appropriate supporting data was not provided for the EPA's review.

DU's Response: See Section 2.2.1 – Site Specific Capital Cost Factors:

Black & Veatch used industry accepted Lang/Guthrie factors modified with data from previous projects to develop a more accurate project estimate. The following items are included in the estimate, that are not captured by the EPA Cost Manual approach to estimating. Thorough descriptions of these adjustments are included in the report:

1. Adjustments for Alaskan wage rates
2. Adjustments for Alaskan labor productivity

3. Interconnecting duct work and supports
4. Electrical equipment
5. New common stack
6. Construction Management & Startup costs are based on staff count and duration
7. Buildings are sized and priced on a $/SF basis

3) EPA Comment: Excluded Pneumatic CDS Design

For circulating dry scrubbers (CDS), one vendor provided an alternative design approach and cost estimate based on utilizing the existing baghouse (as opposed to installing a new baghouse). The vendor estimate for this control option was approximately 1/3 the capital cost of CDS when a new baghouse is included. In response to the EPA's comments on the draft report which requested the basis for rejection of this design option, Doyon provided a general statement that this design option differed from traditional CDS designs and cited concerns over plugging related to pneumatic transport of the fly ash and hydrated lime. The evaluation of the proposed design to utilize the existing baghouse must be based on more specific information such as whether the proposed pneumatic conveyance approach for CDS has ever been installed by the vendor as proposed, as well as specific concerns regarding pneumatic conveyance and its application as proposed in the vendor design. In summary, the record must include the detailed basis for any technical infeasibility determination.

DU's Response: See Section 4.1 – Budgetary Quote Review

A new circulating dry scrubber system (CDS) cannot reuse the existing pulsed jet fabric filter (PJFF) baghouse for two reasons. First, a CDS system generates additional particulate loading which the existing baghouse is not equipped to handle. Secondly, CDS systems cannot use the existing baghouse because the reactor vessel requires solids recirculation from an elevated baghouse via trough hoppers and air slides. This has been defended by both Andritz and LDX Solutions.

The alternative CDS approach proposed by Tri-Mer that reuses the existing baghouse is a pneumatic design that differs significantly from traditional CDS designs offered by other vendors. This difference warrants additional consideration of the vendor reference list and potential design flaws for the CHPP installation. The vendor reference list provided for this variation showed that the pneumatic design had only been installed in one other US coal-fired boiler facility. This installation injected into a slip stream without a reactor vessel and had significantly shorter duct runs for recirculation. This facility ceased combusting coal approximately four years ago and this control device is no longer in use at the facility. The design proposed for the CHPP would have a reactor vessel and duct runs [redacted] longer due to the proposed location of the CDS system across the street. The alternative pneumatic design is not considered technically feasible for the CHPP facility due to a lack of successful installations, especially at similar facilities. DU is hesitant to consider this technology as "available" for purposes of the BACT analysis because this control device was only installed at one similar facility and is no longer in use.

4) **EPA Comment: Attribution of Electricity Increase in Cost Analysis**

In the cost analysis for CDS where a new baghouse is required, only the increase in electricity use as compared to the operation of the current control system may be attributed to the CDS.

DU's Response: See Section 5.1 – Control Effectiveness

The auxiliary and ID fan power was reevaluated for the CDS technology. The pressure drop across the existing baghouse corresponds with a fan power draw of 105 kW. The total reduction in auxiliary power across all [redacted] systems is [redacted] kW. This was subtracted from the cost-analysis for electricity usage.

5) **EPA Comment: Average of Vendor Bids**

The EPA maintains that the lowest vendor cost estimates should be used for the cost effectiveness analyses. The EPA does not have a basis to question the veracity of any of the estimates provided, and the lowest cost estimates do not appear to be outliers compared to the other estimates. The cost averaging approach used in the EPA Cost Manual was used to support the development of cost algorithms for particular control technologies applicable to a broad set of emission sources and is not applicable to projects where site-specific equipment quotes have been obtained.

DU's Response: See Section 4.1 – Budgetary Quote Review

While there is no basis to question the veracity of any of the estimates provided, it is important to note that each quote was budgetary in nature. Because the EPA approved work scope was for a ±30% study, the quotes developed by the vendors were not based on a complete specification and a thorough evaluation and equalization of the proposals was not performed. Due to the potential for inaccuracy in the proposals and the lack of time to fully equalize all bids, the use of an average value provides a more reliable estimate that is expected to be more accurate.

The approach presented in this analysis is an appropriate method to develop a study-level cost estimate reflective of actual expected costs to the owner. Black & Veatch believes that this approach is not inconsistent with the CCM or other related documentation regarding cost estimates.

6) **EPA Comment: Cost of Electricity in Cost Analysis**

Since the facility will be producing its own electricity and this will be used to power the controls and not sold to the grid, it is not appropriate to use the general market electricity cost since the facility will not actually incur this cost. The electricity cost used in the analysis should be the busbar cost, or the cost to the plant to generate the electricity.

DU's Response: See Section 5.1 – Control Effectiveness, and Tables 5-5 & 5-6

This facility is designed and operated to provide steam for the Army base with power generation being a secondary benefit. As the primary focus is steam production, redundancy, and the ability to rapidly respond to upset conditions, multiple units are typically in operation resulting in a higher than normal electrical generation cost. Cost summary breakdown was provided for both CHPP produced power (Table 5-5) and the imported power (Table 5-6). DU typically imports [redacted] of their power needs from outside utilities; thus, a weighted average of [redacted] kWh has been selected for electricity costs.

7) **EPA Comment: Owner's Costs Line Item**

Regarding line items included by Doyon in owner's costs, the EPA Cost Manual estimates for indirect installation costs such as engineering, construction and field expenses include many of these line items as discussed in Section 1, Chapter 2 of the EPA Cost Manual. Thus, the line items included as owner's costs in Doyon's report are likely to be double counting costs that should already be in the engineering, construction and field expenses cost items. In addition, a number of items offered by Doyon as legitimate expenses under owner's costs are not included in the Cost Manual methodology. The EPA maintains that such items should not be included in the cost analysis.

DU's Response: See Section 2.2.1 – Capital Costs Estimate, Owner's Costs

Because owner's costs are not allowed by the EPA cost methodology, this line item has been removed and is no longer included in the cost estimates.

8) **EPA Comment: Specification of 10:1 Turndown Ratio in Design**

The Request for Proposals (RFP) Doyon sent to the air pollution control vendors specified a turndown ratio of 10:1 on an individual boiler basis. The EPA questions the necessity of such an extremely high turndown, requiring that the control equipment be designed to operate down to an individual boiler operating at only 10 percent of its rated capacity. Vendors and Doyon's consultant indicate in the project documentation how rare and unusual this turndown requirement is and that this does not appear to be representative of how the plant actually operates. It is clear from the documentation that this requirement has precluded more cost-efficient control equipment design configurations. In response to this comment by the EPA, Doyon cited wintertime conditions with extremely low temperatures, but this operating scenario would reflect high-end operation of multiple boilers and does not explain the need to operate a single boiler at 10 percent capacity. Based on the project information, the EPA considers the vendor cost estimates to generally be conservative due to the RFP requirements.

DU's Response: See Section 2.1 – Design Basis and Criteria

A turndown ratio of 10:1 was specified in the RFP for multiple reasons due to anticipated permit compliance and the unique demands placed on the CHPP. DU's CHPP boiler operation[redacted] to meet Fort Wainwright's critical infrastructure steam and electric demand is to have one additional boiler online beyond the actual number required to meet the facilities operating requirements. In addition, emission compliance with future permits is anticipated to begin at minimum turndown when the boilers are online and steam is entering the CHPP header system, which is at[redacted] pounds. The design and installation of any CHPP emission control equipment demands the ability to support operations which allows flexibility and operability between[redacted] boilers through all ambient conditions.

Regarding the effect on vendor bids, vendors were queried on this concern, asking if reducing the turndown requirement from 10:1 to 5:1 would significantly impact the overall bid. Andritz expected cost reductions between 0 and 1.2 percent for each of their technologies, Tri-Mer expected 1 to 3 percent reduction in cost for both offered caustic-WFGD and CDS technologies, while B&W Environmental expected no change in cost for the SDA, and slight but unknown reductions in cost for the caustic-WFGD and CDS. The 10:1 turndown basis for this analysis is appropriate to the DU CHPP operational requirements. Costs for a lower turndown ratio would not differ significantly from the cost estimates developed in this analysis based on a 10:1 ratio, further justifying that the costs based on a 10:1 turndown are realistic and appropriate for the analysis.

9) EPA Comment: Lower BACT Limit

The controlled emission rate of 0.04 lb/MMBtu reflects a relatively low control efficiency as SO_2 BACT (93.1 percent), considering the capabilities of both wet scrubbing technologies and CDS. One vendor specifically stated that caustic wet scrubbing can achieve 98 percent control for this application. The EPA considers 0.04 lb/MMBtu conservative and easily attainable by these technologies. Based on the project record and vendor statements, a lower limit is likely achievable as BACT.

DU's Response: See Sections 5.1 and 5.2.3 – Control Effectiveness

The emission rate of 0.04 lb/MMBtu is equivalent to 93.1-percent removal. While control technologies have demonstrated removal rates of well over 90 percent, it is erroneous to universally apply these reduction percentages. There is a floor to the pollution concentration that control technologies can achieve, and if a power plant starts with a low concentration (e.g., the DU FWA CHPP and other facilities that burn low-sulfur coal), the achievable removal percentage will be lower.

Some control technologies, such as a WFGD and CDS have achieved removal rates upwards of 98 percent on units emitting high levels of sulfur. If a 98-percent SO_2 removal rate was applied to the CHPP's baseline emission rate, this would equal an SO_2 emission rate of 0.01 lb/MMBtu or lower depending on the actual sulfur of the coal. The 0.01 lb/MMBtu emission rate is an unattainable mass emission rate, because it is lower than what FGD systems have been able to achieve on a consistent basis. Process upset conditions, startup, shutdown, and maintenance periods, and variability in fuel sulfur content further affect the achievability of meeting a 0.01 lb/MMBtu rate.

Vendors were queried for minimum emission rates for each technology. The rates varied between vendors, but the lowest emission rates were for caustic-WFGD and CDS at 0.02 lb/MMBTU (96.6-percent control). Average values from the Air Markets Program Database (AMPD) cast uncertainty on how achievable these rates are in practice. The rate of 0.04 lb/MMBtu best represents the lowest achievable emission rate for the facility.

10) EPA Comment: AFUDC Line Item

The EPA maintains that allowance for funds used during construction (AFUDC) is not an allowed cost as per the methodology in the EPA Cost Manual.

DU's Response: See Report Section 2.2.1 – Capital Costs Estimate, AFUDC

Because AFUDC are not allowed by the EPA cost methodology, this line item has been removed and is no longer included in the cost estimates.

11) EPA Comment: Weighted Cost of Capital

Doyon needs to provide references and documentation to support their weighted average cost of capital (WACC) [redacted] and the report should be revised to cite this information as the basis for the interest rate used. The documents must provide references and basis for the equity rate and the debt rate used to calculate the WACC.

DU's Response: See Section 2.2.1 – Site Specific Capital Cost Factors, Table 2-4

An interest rate of [redacted] more accurately describes DU's deemed structure on total capitalization. DU is financed with a combination of debt and equity. The interest rate is calculated as a weighted cost of capital (WACC) from the return percentages from both debt and equity. DU's contracted debt/equity ratio is 60 percent debt and 40 percent equity or 60/40. The average debt return is 4.125 percent, while the equity return is set by DU's privatization contracts at 12.5 percent. Weighting these two return percentages by the 60/40 ratio results in a WACC interest rate[redacted].

DU has provided additional description and contract language in the report to support the capitalization structure and WACC[redacted]

12) EPA Comment: Vendor Quote Discrepancy

For caustic WFGD, Doyon's report cites the Tri-Mer quote for the capital cost as [redacted] (see Table 4-1). However, the quote provided by Tri-Mer is[redacted] per boiler, or [redacted] total. The value listed in the Doyon report is approximately 10 percent higher than the quote provided by Tri-Mer.

DU's Response: See Section 4.1 – Budgetary Quote Review

Tri-Mer's first budgetary proposal for the caustic-WFGD [redacted] did not include several necessary items: [redacted] interconnecting ductwork that would be required for the caustic WFGD to be located across the street of the current baghouse, ID fans, and motor VFDs needed to account for the added pressure drop of new equipment and ductwork, or the final stack.

In follow-up discussions with Tri-Mer, their representatives stated the ductwork and stack would be approximately [redacted] for each technology but could not yet provide an estimate for the ID fans and motor. Lacking a direct value from Tri-Mer, their quote was supplemented with the breakout cost of [redacted] provided by a different vendor (Andritz's quote provided this cost as a breakout). The stated value in the cost estimate from the report is thus [redacted] (the total of [redacted] and [redacted]).

<u>Other Items of Discussion:</u>

A) Potential Safety Risks from Ice Fog Formation: See Section 6.2 and Appendix F

Doyon Utilities has identified the generation of ice fog as a serious collateral environmental impact associated with the increased moisture in the exhaust gas. Ice fog can also be associated with frost formation which can accumulate on powerlines, aircrafts, roads, and other infrastructure. The CHPP is located within one mile of the Richardson Highway, a main thoroughfare in the Fairbanks area. The Richardson Highway connects Fairbanks to the Alcan highway through Canada, the only road connection between Alaska to the continental United States. In addition to problems with the Richardson Highway, ice fog has also led to visibility concerns for airplanes in the region. Fort Wainwright's Ladd Army Airfield is located less than 0.5 miles northeast of the CHPP.

B) WFGDs Potential for New Landfill and Wastewater Treatment Facility: See Section 6.2

The cost estimates used a flat rate for disposing of solids and wastewater which is based on current costs for sending solids to the existing landfill and water to the site's wastewater treatment facility. Engineering efforts will be required for proper management of both these waste streams, which will have a significant impact on the cost effectiveness calculated as part of this analysis. Because neither item is included in the analysis, the cost-effectiveness values presented in the report are believed to be much lower than the actual incurred cost per ton of SO_2 removed if one of these technologies were to be implemented.

C) Discussion on GVEA Cost Effectiveness Precedent: **See Section 6.3**

DU believes that the DSI SO_2 removal cost effectiveness of [redacted] compared to the Caustic Wet Scrubber SO_2 removal cost effectiveness of [redacted] is not relevant in comparison to the analysis performed at GVEA.

There are three main points that highlight why EPA/ADEC's acceptance of a control measure with a relatively high-cost effectiveness should not be interpreted as justification for a control measure with a similar cost effectiveness at DU's FWA facility.

1. GVEA had no other feasible SO_2 control options.
2. The cost per ton of SO_2 removed at GVEA's NPPP was only determined cost effective because of the significant amount of SO_2 reduction to be realized.
3. ADEC ultimately determined that GVEA is only required to burn ULSD between October 1 and March 31 of each year, reducing the financial burden compared to the costs presented in the ADEC BACT determination.

FINAL

CHPP SO_2 REDUCTION ANALYSIS

Fort Wainwright

B&V PROJECT NO. 406418
B&V FILE NO. 40.1000

PREPARED FOR

DOYON UTILITIES LLC

Doyon Utilities

25 AUGUST 2021

BLACK & VEATCH

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Acronym List

AACE	Advancement of Cost Engineering
AQC	Air Quality Control
BACT	Best Available Control Technologies
B&W	Babcock & Wilcox
BOP	Balance-of-Plant
CAA	Clean Air Act
CDS	Circulating Dry Scrubber
cfm	Cubic Feet per Minute
CHPP	Central Heat and Power Plant
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DAC	Direct Annual Cost
DC	Direct Cost
DEC	Department of Environmental Conservation
DSI	Dry Sorbent Injection
DU	Doyon Utilities, LLC
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPA CCM	EPA Air Pollution Control Cost Manual
EPC	Engineering, Procurement, and Construction
ESP	Electrostatic Precipitator
FNSB	Fairbanks North Star Borough
FWA	Fort Wainwright
gpm	Gallons per Minute
HCl	Hydrochloric Acid
ID	Induced draft
IDAC	Indirect Annual Cost
klbm	Kilo-pound (mass) - 1000 x Pounds
kV	Kilovolts
kVA	Kilovolt-Amperes
kW	Kilowatt
lb/h	Pounds per Hour
MCR	Maximum Continuous Rating
MMBtu	Million British Thermal Unit
NAAQS	National Ambient Air Quality Standards
NO_x	Nitrogen Oxides
O&M	Operation and Maintenance
O_3	Ozone
Pb	Lead
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter

psig	Pounds per Square Inch Gauge
RFP	Request for Proposal
SBC	Sodium Bicarbonate
SDA	Spray Dry Absorber
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TAC	Total Annual Cost
TCI	Total Capital Investment
tph	Tons per Hour
UCC	United Conveyor Corp
V	Volts
VOC	Volatile Organic Compounds
WFGD	Wet Flue Gas Desulfurization
$\mu g/m^3$	Micrograms per Cubic Meter

Executive Summary

Doyon Utilities, LLC (DU) owns and operates the central heat and power plant (CHPP) that serves the United States Army base at Fort Wainwright (FWA), Alaska, which is situated within the Fairbanks North Star Borough (FNSB). A portion of the FNSB which includes the Garrison area of FWA has been categorized as a serious nonattainment area for meeting the 2006 National Ambient Air Quality Standards (NAAQS) for 24-hour fine particulate matter (PM)/$PM_{2.5}$. As a result, the Alaska Department of Environmental Conservation (DEC) developed a Serious State Implementation Plan (SIP) for identifying future steps to bring the FNSB into compliance with the NAAQS. The Serious SIP was submitted on December 13, 2019 and the US Environmental Protection Agency (EPA) determined the plan met the completeness criteria on January 9, 2020. The Serious SIP included a Best Available Control Technology (BACT) analysis for emissions sources in the area, and a dry sorbent injection (DSI) system was identified as a cost-effective solution for sulfur dioxide (SO_2) emissions, which contribute to overall PM emissions.

The EPA reviewed the Serious SIP and has requested additional information. This included a request for more thorough analysis and cost estimations of other alternative SO_2 control technologies, specifically caustic and limestone wet flue gas desulfurization (WFGD), a spray dry absorber (SDA), and a circulating dry scrubber (CDS). A “top down”, five-step BACT analysis was prepared to determine the appropriate emission control technology and emission limitation for [redacted] boilers at CHPP. The BACT analysis was conducted on [redacted] boilers in accordance with the EPA’s recommended methodology:

- Step 1 -- Identify All Available Control Technologies
- Step 2 -- Eliminate Technically Infeasible Options
- Step 3 -- Rank Remaining Control Technologies by Control Effectiveness.
- Step 4 -- Evaluate Most Effective Controls.
- Step 5 -- Select BACT.

The effectiveness of each control technology was selected from the average SO_2 removal rates of the top 20 and 50 percent of U.S. coal-fired power plants according to the EPA Air Pollution Control Cost Manual (CCM)[1]. Based on this information, the minimum emission rates for this study assumed 0.12 lb/MMBtu for DSI, 0.07 lb/MMBtu for CDS, 0.07 lb/MMBtu for SDA, and 0.04 for caustic/limestone-WFGD. Additional follow-up with SO_2 control technology vendors was performed to identify minimum emission rates for each technology within a 3-hour time-averaging period. The minimum rates varied between vendors, but the lowest emission rates were 0.02 lb/MMBtu for CDS, 0.04 lb/MMBtu for SDA, and 0.04 for limestone-WFGD, and 0.02 for caustic-WFGD. Black & Veatch believes that these rates are overly optimistic, particularly the CDS and caustic-WFGD technologies when compared with historical EPA emissions data from the Air

[1] 2020 EPA CCM, Section 5, Table 1.3: 12-month average SO_2 emission rates for 2019 coal-fired power plants

Markets Program Database (AMPD)[2]. A separate sensitivity study with these reduced emission rates is included for reference but does not affect the overall conclusions of this report.

Black & Veatch developed +/- 30 percent cost estimates with a desktop analysis for each of these technologies. All systems were designed as a 1:1 scrubber to boiler basis, except for the WFGD systems which have greater turndown capabilities and were designated as 2:1. This design is critical for the operation of the CHPP facility which demands the flexible load-sharing [redacted] through all ambient conditions. These estimates were based on information provided by DU, a virtual tour, and assumptions based on Black & Veatch's past projects and experiences. A request for proposal (RFP) was created and sent to six (6) SO_2 scrubber system providers (Andritz, B&W Environmental, LDX Solutions, Tri-Mer, General Electric, and MACH Engineering). Budgetary quotes and preliminary equipment sizes were returned from four (4) of the six vendors, and with consideration of comparable design, Andritz, B&W, and Tri-Mer were used as the basis for this study's cost estimate and engineering design. The cost estimates for WFGD, SDA, and CDS installation are aligned with the current design and installation plans.

Conceptual engineering and design efforts were used to develop a cost estimate for the installation of each emissions control system. The major equipment costs were taken from Andritz, B&W, and Tri-Mer's budgetary quotes, and supplementary materials costs were estimated using Black & Veatch's project database of recently completed projects and proposals or factored estimates as directed in the EPA CCM. Installation costs used prevailing wages for the state of Alaska, and the manhours required to install each component were estimated from Black & Veatch's project database. The manhours were adjusted for regional working conditions using factors from Compass International and B&V project experience (e.g. more manhours are required to perform equivalent tasks in cold environments than in warmer climates).

Table ES-1 summarizes the project costs calculated as part of this study. All costs presented represent SO_2 emissions control for [redacted] boilers.

Table ES-1 Capital Cost Summary (All Costs are in 2021$)

CATEGORY	WFGD – CAUSTIC	WFGD – LIMESTONE	SDA	CDS	DSI
Direct Costs (DC)					
Purchased Equipment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Installation Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Site Prep & Buildings	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Indirect Costs (IC)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

In addition to capital costs, annual operational and maintenance costs were developed. Direct annual costs (DAC) include fixed costs, such as labor and maintenance, and variable annual costs, such as reagents or other consumables. The number of full-time employees necessary to run

[2] Air Markets Program Data | Clean Air Markets | https://ampd.epa.gov/ampd/

each control technology varies, with as little as one (1) for DSI, or as many as eight (8) for a limestone WFGD system. Maintenance costs follow the EPA CCM recommendations for maintenance labor and materials. Variable annual costs are predominantly driven by the cost of the selected reagent. Water and sewer costs are included at [redacted] and [redacted] respectively per DU's information. The cost of power is included [redacted] cents/kilowatt-hour based on DU's 2020 average. Disposal costs for additional solids is assumed to be [redacted] based on past Black & Veatch projects, but this value could increase if the FWA landfill is no longer available for the CHPP.

For purposes of BACT, annual costs are adjusted by an operational capacity factor according to the facility's potential-to-emit (PTE). Based on the facility's overall coal consumption limit[3] [redacted] the corresponding PTE heat input of the plant[4] is [redacted]/yr. Given the unlimited plant operation of [redacted]/yr, the overall capacity factor is 39 percent. The cost per ton of SO_2 removed is based on [redacted] and a 30-year life of the scrubber system. Table ES-2 summarizes the annual costs and the overall cost effectiveness of each technology.

Table ES-2 Annual Cost Summary (All Costs are in 2021$)

CATEGORY	WFGD – CAUSTIC	WFGD – LIMESTONE	SDA	CDS	DSI
Direct Costs					
Fixed Annual Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Annual Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Indirect Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Annual Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tons of SO_2 Removed	1,369	1,369	1,293	1,293	1,167
$ / Ton SO_2 Removed*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* The summary costs per ton of SO_2 removed are budgetary in nature and will likely be more expensive, particularly for technologies that contribute significant collateral environmental impact in the form of ice fog, water and wastewater, and landfill waste. These effects are difficult to quantify but are discussed in further detail in Section 6.2.

Per the Annual Cost Summary, the DSI system represents the lowest-cost option at [redacted] annually followed by the WFGD-Caustic system at [redacted], the WFGD-Limestone system at [redacted], the SDA at [redacted] and the CDS at [redacted]. Typically, WFGDs have a higher capital cost than semi-dry scrubbers, but in this study, WFGD systems are cheaper than the SDA and CDS. This is because the WFGD systems are designed to have two boilers feed into one WFGD system compared to the SDA and CDS that are designed for one boiler feeding into one SDA/CDS. WFGD systems have a much lower turn down ratio compared to an SDA or CDS, allowing DU to retain their operational flexibility even with two boilers feeding a common vessel. The CDS is the most expensive because it requires the installation of a new pulse jet fabric filter (PJFF) system.

[3] CHPP Title V coal consumption limit
[4] Based on [redacted] coal heat content of 7,560 Btu/lb | [redacted]

This budgetary study has only considered the costs of equipment and installation and has not included costs for ancillary items that may need to be addressed. For instance, both WFGD technologies generate significant waste streams which may necessitate the construction of a new water treatment facility. WFGD technologies also pose a safety concern for the facility and surrounding community. The wet systems contribute to a 53-percent increase in flue gas moisture content which leads directly to more icing/frost accumulation in and around the facility. In addition, increased moisture exacerbates ice fog events which are common in the Fairbanks area. Ice fog has directly contributed to accidents on the neighboring highway and a crashed plane at the nearby airport. Increased moisture would likely worsen ice fog events by increasing the quantity and length of ice fog plumes in public areas. Mitigation of the increased moisture content would require expensive dewatering well beyond that of traditional flue gas treatment systems due to the strong low-level inversion typical of the weather event. Mitigation efforts would likely make these control technologies more costly, further increasing the cost per ton of SO_2 removed.

In Black & Veatch's experience, the cost-effectiveness values calculated for the caustic-WFGD, limestone-WFGD, CDS, and SDA technologies are greater than values found to be not-cost effective in other BACT analysis. After the application of the five-step BACT analysis, and consideration of further waste treatment costs, environmental hazards, and safety concerns, Black & Veatch believes that the only cost-effective BACT solution for Doyon Utilities' CHPP facility is the installation of a DSI system to the presumptive emissions control level of 0.12 lb SO_2/MMBtu. DSI is the most cost-effective option by a large margin and poses no additional safety risks towards ice fog events or considerable management of waste byproducts. The increased risk of collateral environmental impact of ice fog and waste byproducts are discussed further in Section 6.2.

1.0 Introduction

Doyon Utilities, LLC (DU) is a private, multi-service utility that owns and operates a coal-fired power plant located within the United States Army base at Fort Wainwright, Alaska. The power plant is termed the Central Heat and Power Plant (CHPP), and it provides heating steam and electric power for the base. The CHPP [redacted] boilers [redacted] designed to produce [redacted]

Due to elevated air pollution in the general Fairbanks area, the Alaska Department of Environmental Conservation (DEC) will require an additional air pollution control system to be installed at the CHPP. This report provides +/- 30 percent cost estimates for an SO_2 control system at the CHPP, along with the “study-level” (per EPA CCM) analysis that was performed to support this cost estimate.

1.1 PARTICULATE MATTER (PM) AND SULFUR DIOXIDE (SO_2)

PM and SO_2 are both criteria pollutants, and the scrubber system at FWA will control SO_2 emissions. PM can be classified in several ways. In terms of NAAQS, PM is segregated into two main categories: PM10, which is PM that is 10 microns or smaller, and PM2.5, which is PM that is 2.5 microns or smaller. PM2.5 is primarily from combustion processes, such as power plants, vehicular emissions, wood combustion for thermal heat, and secondary reactions of chemical compounds.

SO_2 is one of the chemical precursors to PM2.5 emissions; SO_2 can create PM2.5 by being oxidized into SO_3 and reacting with ammonia particles. Studies have also shown that SO_2 has a significant effect on the formation of secondary organic aerosols in the presence of NOx and volatile organic compounds (VOCs). For these reasons, even if a region meets the NAAQS for SO_2, SO_2 emissions must be evaluated for a region if it does not meet the NAAQS for PM2.5.

1.2 CLEAN AIR ACT AND NON-ATTAINMENT

The Clean Air Act (CAA), first passed by the US Congress in 1970 and significantly revised and expanded in 1990, sets limits on certain air pollutants’ ambient concentrations. The CAA requires the United States EPA to set limits for six criteria pollutants: carbon monoxide (CO), ozone (O_3), lead (Pb), nitrogen oxides (NOx), PM, and SO_2. These limits are referred to as the National Ambient Air Quality Standards (NAAQS) and must be met by all states, but the states can impose stricter limits if they so choose. States are also involved in implementing strategies to monitor and control air pollution to meet the NAAQS. These strategies are outlined in each state’s SIP.

Alaska submitted their first SIP in 1972, which addressed CO, SO_2, and PM. PM is a unique challenge for the state of Alaska because of the use of wood as a heating source by many communities. Further compounding the PM problem are unpaved roads and point sources in the state. Despite these challenges, Alaska was in compliance with the PM2.5 standards from 1997 to 2006. In 2006, the EPA tightened the regulation on the 24-hour fine particle standard (PM2.5, or PM that is 2.5 microns or smaller) from 65 $\mu g/m^3$ to 35 $\mu g/m^3$. In December 2009, a portion of the

FNSB, which includes the Garrison area of Fort Wainwright, was designated by the EPA as a moderate nonattainment area (an area that exceeds the EPA's ambient air quality limits for critical pollutants) for PM2.5. The ambient air concentrations in this portion of the FNSB consistently exceeded the new limit, with a 3-year average from 2006 to 2008 of 43 μg/m^3, with the highest pollution levels occurring during the winter months.

Following the EPA designation, the Alaska DEC developed a SIP to address the elevated pollution levels in the area. This "Moderate Area SIP" was submitted to the EPA in December 2014 and approved by the EPA in September of 2017. Unfortunately, a compliance date of December 31, 2015 could not be met by the DEC, and monitoring data showed that the offending portion of FNSB continued to be a nonattainment area. Therefore, the EPA reclassified the region as a serious nonattainment area. With the new designation, a new Serious SIP was developed to identify steps to lower the pollution levels below the NAAQS. On November 19, 2019, the ADEC approved its Serious SIP, which identified BACT for point sources in the area. Federal code requires the Serious SIP to identify and implement best available control measures (BACM) and BACT for applicable pollution sources. FWA was one of the facilities that was evaluated under the BACT process, and DSI was identified as a cost-effective solution for limiting SO_2 emissions. The DSI would control SO_2 emissions from the CHPP to 0.12 lb/MMBtu over a 3-hour average, and DU has been progressing in engineering efforts on the DSI system [redacted] with Black & Veatch [redacted]

At this time, the EPA has not yet proposed to approve the control strategy portion of the SIP. To better support this portion of the SIP, this follow-up BACT analysis was performed by DU and Black & Veatch and consisted of the following steps:

- Step 1 -- Identify All Available Control Technologies
- Step 2 -- Eliminate Technically Infeasible Options
- Step 3 -- Rank Remaining Control Technologies by Control Effectiveness.
- Step 4 -- Evaluate Most Effective Controls.
- Step 5 -- Select BACT.

1.3 BACT ANALYSIS

This report seeks to review the cost and effectiveness of the most stringent alternative SO_2 control technologies. A brief description of each of the five steps performed is provided in the following subsections.

1.3.1 Identify All Available Control Technologies (Step 1)

The first activity of the BACT analysis methodology is to identify all available control technologies. An emissions control technology is considered an available option if it has practical potential for application to the BACT-eligible source. An available option can be a system, technology, or change in operational method for the control of a pollutant. Technologies that have been successfully applied to similar sources or with similar gas stream characteristics shall also be considered as available. However, technologies that have not been applied to full or commercial scale operations are not considered to be available. If the source is equipped with existing control technologies, control options should include improvements or optimization of the existing control technologies. Section 3.0 addresses the requirements of Step 1 of the BACT analysis.

1.3.2 Eliminate Technically Infeasible Options (Step 2)

Step 2 of the BACT analysis involves the evaluation of all the identified available retrofit control technologies to determine its technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. Section 4.0 addresses the requirements of Step 2 of the BACT analysis.

A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage / research and patenting) and testing stages (bench scale / laboratory testing / pilot scale testing) are classified as not available. The commercially available technology is applicable if it has been previously installed and operated at a similar type of source of comparable size, or a source with similar gas stream characteristics. Section 4.0 addresses the requirements of Step 2 of the BACT analysis.

1.3.3 Rank Remaining Technologies by Control Effectiveness (Step 3)

The third step of the "top-down" analysis is to rank all the remaining control alternatives not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, it is not necessary to provide cost and other detailed information for other less effective control options.

The expected control effectiveness of a technology can be obtained by considering regulatory evaluations for the technology, performance data provided by manufacturer (usually in the form of a performance guarantee), engineering estimates, or demonstrated effectiveness of the technology at another facility. The most stringent level of control of each technology should be used for its control effectiveness but less stringent levels of control can be considered as additional options. Section 5.0 demonstrates the evaluations performed for Step 3 of the BACT analysis.

1.3.4 Evaluate Most Effective Controls (Step 4)

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed to make a BACT determination in Step 4. The impacts of the technology implementation on the viability of the control technology at the source are evaluated. The evaluation process of these impacts is also known as "Impact Analysis." The following impact analyses are performed for the remaining alternatives:

- Energy evaluation of alternatives.
- Environmental evaluation of alternatives.
- Economic evaluation of alternatives.

The first impact analysis addresses the energy evaluation of alternatives. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which affects the cost-effectiveness of the control technology.

The second impact analysis addresses the environmental effects of alternatives. Non-air quality environmental effects are evaluated to determine the cost to mitigate the environmental effects caused by the operation of a control technology. Examples of non-air quality environmental impacts include polluted water discharge and solids or waste generation. The procedure for conducting this analysis should be based on a consideration of site-specific circumstances.

The third and final impact analysis addresses the economic evaluation of alternatives. This analysis is performed to assess the cost to purchase and operate the control technology. The capital and operating/annual costs are estimated based on design parameters established. Information for the design parameters should be obtained from established sources that can be referenced. However, documented assumptions can be made in the absence of references for the design parameters.

The estimated cost of control is represented as an annualized cost ($/year), and with the estimated quantity of pollutant removed (tons/year), the cost effectiveness ($/tons) of the control technology is determined. The cost effectiveness describes the potential to achieve the required emissions reduction by the most economical means. The cost effectiveness compares the potential technologies on an economical basis. Two types of cost effectiveness are considered in a BACT analysis; average and incremental cost effectiveness. The average cost effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. It has a unit of ($/incremental ton removed). The incremental cost effectiveness is a good measure of economic viability when comparing technologies that have similar removal efficiencies.

1.3.5 Select BACT (Step 5)

The highest ranked control technology that is not eliminated in Step 4 is proposed as BACT for the pollutant and emission unit under review. As summarized in Table 1-1, the BACT analysis process resulted in the following control technology and emissions level determination for DU'[redacted]

Table 1-1 BACT Determination Summary[redacted]

POLLUTANT	CONTROL TECHNOLOGY	EMISSION BASIS	AVERAGING PERIOD
SO_2	DSI	0.12 lb/MMBtu	3-Hour Average

2.0 Plant Description

FWA, formerly known as Ladd Air Force Base, is an Army base located immediately east of Fairbanks, Alaska, within the FNSB. The base covers over seven (7) square miles and is home to about 12,000 people. The CHPP provides heating steam and electric power for the base.

The CHPP was originally constructed in two phases, in 1949-50 and 1954. Originally, two steam generators, a 2 MW non-condensing generator, and a 2 MW condensing turbine generator were installed. These steam generators were later abandoned, and [redacted] generators were installed along with [redacted] turbine generators rated at 5 MW each. At the same time, the old 2 MW condensing turbine generator was also replaced with a 5 MW condensing turbine generator.

Each steam generator is [redacted] designed to produce [redacted] The boilers' economizers reduce the flue gas temperature to about 277° F, and no air heater is installed. Flue gas is directed from the economizer to a set of PJFF compartments before exhausting out the stack.

2.1 DESIGN BASIS AND CRITERIA

Using information from DU, vendors, and virtual and local third-party walkdowns of the site (due to COVID-19 restrictions, in-person walkdowns by Black & Veatch personnel could not be executed), a design basis was developed for the facility. Black & Veatch provided the data included in Table 2-1 and Table 2-2 to multiple SO_2 scrubber vendors in an RFP to request budgetary costs and sizes for the three emission control technologies (wet scrubber, dry scrubber, and circulating dry scrubber). Their responses were used as a basis for the engineering design. The budgetary quotes are discussed in greater detail in Section 4.1.

The fuel source for the CHPP is coal [redacted]. Proximate coal analyses from January through September 2020 were averaged and converted to an ultimate analysis as shown in Table 2-1. The average sulfur content for this time period was 0.14 percent, but the calculations in this report reflect the permit limit of 0.25 percent coal sulfur content to account for maximum design conditions and reflect potential to emit. Black & Veatch developed combustion calculations based on the coal data and unit operating data to estimate flue gas characteristics. The referenced data and calculated results are summarized in Table 2-2 and align with values obtained from stack tests conducted in 2017.

Table 2-1 [redacted] Coal - 2020

FUEL PROPERTY (WET BASIS)	PROXIMATE ANALYSIS	ULTIMATE ANALYSIS
Carbon, %	27.00	48.65
Volatiles, %	35.45	NA
Hydrogen, %	NA	3.44
Sulfur, %	0.14	0.14
Nitrogen, %	NA	0.89
Oxygen, %	NA	9.22
Ash, %	7.53	7.53
Moisture, %	30.02	30.02
Total, %	100	100
Higher Heating Value, Btu/lb	7,510	7,510

Table 2-2 Boiler and Flue Gas Conditions (Single Boiler)

FUEL PROPERTY (WET BASIS)	UNIT	DESIGN VALUE
Boiler Data		
Main Steam Flow	lb / hr	150,000
Main Steam Pressure	psig	425
Main Steam Temperature	°F	700
Feedwater Pressure	psig	692
Feedwater Temperature	°F	240
Economizer Outlet Pressure	in w.g.	- 2.2
Economizer Outlet Temperature	°F	277
Flue Gas		
Oxygen	lb / hr	7,584
Nitrogen	lb / hr	154,954
Argon	lb / hr	2,587
Carbon Dioxide	lb / hr	48,049
Sulfur Dioxide	lb / hr	135
Chlorine	lb / hr	0
Total Dry Flue Gas	lb / hr	213,309
Moisture	lb / hr	18,513
Total Wet Flue Gas	lb / hr	231,823

A turndown ratio of 10:1 was specified in the Request for Proposals (RFP) sent to air pollution control vendors. This operational condition was selected for multiple reasons due to anticipated permit compliance and the unique demands placed on the CHPP. Fort Wainwright is a strategically significant Army installation with a focus on Arctic force projection. The CHPP is critical infrastructure, serving the installation's more than 400 buildings, maintenance facilities, hangars, and residences [redacted]

[redacted]

Resilience and reliability are key factors in the CHPP system design to ensure continued mission support during harsh winter conditions that routinely see temperatures reach -40 Fahrenheit or colder, as well as occasional temperature swings that may exceed 40 to 50 degrees in a 24-hour period. Such conditions require a significant degree of energy-assurance and an unusual flexibility of operations that this system is designed to meet.

In addition, emission compliance with future permits is anticipated to begin at minimum turndown when the boilers are online and steam is entering the CHPP header system, which is at [redacted] pounds. The CHPP's minor permit[6] states that the "feed rate of dry sorbent is proportional to the steam production rate at a ratio equal to or greater than the ratio recorded for the most recent source test…." No matter the selected control technology it is expected SO_2 emission compliance will be required at any load above [redacted]

[redacted]

The design and installation of any CHPP emission control equipment demands the ability to support operations which allows flexibility and operability between [redacted] boilers through all ambient conditions. A 10:1 turndown specification for WFGD, SDA, or CDS equipment supports the Department of Defense's strategy and is aligned with the existing design and installation plans for DSI.

Despite the need for a 10:1 turndown ratio to support the facilities' mission, there is a concern that the large turndown ratio may have affected the vendor designs increasing overall cost. Vendors were queried on this concern, asking if reducing the turndown requirement from 10:1 to 5:1 would significantly impact the overall bid. A 5:1 turndown does not fulfill the CHPP's need for

[5] Calculation from 2020 CHPP Energy Production Hourly Historian Data
[6] June 30, 2021 - FWA CHPP Minor Permit AQ1121MSS04 condition 6.1(a)

full range of operation but may represent typical operation based on historical data. Andritz expected no change in cost for the caustic-WFGD, a 0.5 percent reduction in costs for SDA, and a 1.2 percent reduction in costs for CDS. Tri-Mer estimated a 1 to 3 percent reduction in cost for both offered caustic-WFGD and CDS technologies. B&W Environmental expected no change in cost for the SDA, minor reductions in cost for the caustic-WFGD depending on the reduction of valves and reagent preparation equipment, and an unknown reduction in cost for the CDS depending on the reduction in size of recirculation flues and dampers and whether the boiler to scrubber ratio could be decreased. The 10:1 turndown basis for this analysis is appropriate to the DU CHPP operational requirements. Costs for a lower turndown ratio would not differ significantly from the cost estimates developed in this analysis based on a 10:1 ratio, further justifying that the costs based on a 10:1 turndown are realistic and appropriate for the analysis.

This study uses the control effectiveness ratings for each technology based on the removal rates of the top 20 and 50 percent of U.S. coal-fired power plants according to the EPA CCM[7]. The top 50 percent average of emission rates was targeted for the control technologies, which resulted in 0.04 lb/MMBtu for a WFGD, 0.06 lb/MMBtu for an SDA, and 0.12 lb/MMBtu for a CDS. However, Black & Veatch is aware of many CDS installations that are capable of achieving emission rates lower than 0.12 lb/MMBtu, so the top 20 percent value (0.07 lb/MMBtu) was chosen for the CDS. Black & Veatch has also observed CDS installations outperforming SDA installations at similar plants, so instead of using the top 20 percent value for an SDA (0.04 lb/MMBtu), the SDA has been set to 0.07 lb/MMBtu to be equal to the CDS target.

Average emission rates from the CCM are acceptable for a budgetary level study where it is assumed that the reliability and availability of the technology are high, and that the emission rate can be met for any reasonably expected averaging period. To better evaluate the extent of emissions reductions possible, Black & Veatch requested additional follow-up rates from vendors. In their responses, vendors provided the minimum emission rate within a three-hour time averaging period for their proposed design. The effect of these emission rates on impact and cost effectiveness are discussed further in Section 5.2.3. Vendors provided estimates on utility usage to reach the provided target emission rates and expected waste streams generated, as summarized in Table 2-3.

[7] EPA CCM, Section 5, Table 1.3

Table 2-3 SO_2 Scrubber System Design Criteria

PARAMETER	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS	DSI	SOURCE
SO_2 Emissions Rates, lb/MMBtu	0.04	0.04	0.07	0.07	0.12	See Note
Reagent Type	50% NaOH Solution	Limestone Slurry	CaO Pebble Lime	Hydrated Lime	Sodium Bicarbonate	Vendor Quote
Max Reagent Feed, lb/hr	1,980	1,290	762	1,194	2,550	Vendor Quote
Max Water Feed, gal/hr	11,899	7,200	7,224	7,209	900	Vendor Quote
Silo Storage Time, days	14	14	14	14	28	Doyon RFP
Waste/ Byproduct	Wastewater	Wastewater, $CaSO_4$, $CaSO_3 \bullet x$	Fly ash, $CaSO_4$, and $CaSO_3 \bullet x$	Fly ash, $CaSO_4$, and $CaSO_3 \bullet x$	Na_2SO_4	Vendor Quote
Max Wastewater Flow, gal/hr	3,173	180	-	-	900	Vendor Quote
Max Waste Flow, lb/hr	-	2,478	2,280	2,280	1,980	Vendor Quote
New PJFF necessary	No	No	No	Yes	No	Vendor Quote
Heated Enclosures	Yes	Yes	Yes	Yes	Yes	Doyon RFP

Notes:
1) Emission rates are on a per boiler basis. WFGD, SDA, and CDS emissions rates are from EPA CCM. The basis for selected EPA CCM rates are described in Section 2.1. Vendor-provided emission rates are discussed in Section 5.2.3.
2) Basis for Max Reagent Feed, Max Water Feed, Silo Storage Time, Max Wastewater Flow, and Max Waste Flow are based on [redacted] boilers in operation.

2.2 ECONOMIC DATA

2.2.1 Capital Costs Estimate

Capital costs were developed for retrofit control technologies that were identified as technically feasible for application of Doyon Utilities' [redacted] boilers. The capital cost estimates were based on cost data supplied by the equipment vendor (budgetary estimates) and estimates from previous in-house design/build projects. The capital cost estimates are comprised of direct and indirect costs and are stated in 2021 dollars. The capital cost accuracy is expected to be budgetary at +/- 30 percent. Direct costs consist of purchased equipment and its installation, as well as miscellaneous costs. Indirect costs are those costs that are not related to the equipment purchased but are associated with any engineering project such as the retrofit of an air quality control technology. Indirect costs included in this evaluation include engineering, construction management, start-up and spare parts, performance tests, and contingency. Descriptions of each category are given in the following sections.

Purchased Equipment and Installation Costs

The purchased equipment costs include the supply of all primary and support equipment of the control technology. A full list of the vendor-guaranteed scope, including taxes and freight, is provided in Table 5-3. The installation costs include retrofit related issues based on the existing site configuration and condition.

Miscellaneous Capital Costs

Miscellaneous costs account for additional items such as site preparation, buildings and other structures. The costs estimates were based on the following assumptions:

- Regulatory permitting has been authorized.
- Regular supply of construction craft labor and equipment is available.
- Normal lead-times for equipment deliveries are expected.
- Construction utilities (power, water, air) are provided by the Owner.

Engineering

Engineering costs include any services provided by an architect/engineer or other consultant for support, design, and procurement of the air quality control project.

Owner's Cost

Owner's Costs are not allowed by EPA's cost methodology and will not be included in these cost estimates.

Construction Management

Construction management services include field management staff such as supporting staff personnel, field contract administration, field inspection and quality assurance, project control, technical direction, and management of startup. It also includes cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, other required labor related insurance, performance bond, and liability insurance for equipment and tools.

Start-up and Spare Parts

Start-up services include the management of the startup planning and procedure, and training of personnel for the commissioning of the newly installed air quality control technology. Also included are the general low-cost spare parts required for each air quality control technology system. High cost and critical component spare parts are only kept if recommended by the manufacturer and are determined on a case-by-case basis.

Performance Tests

Performance test services are commissioned after every air quality control technology addition to validate the performance of the emissions reduction system. Typical performance tests are flue gas emissions testing that may be performed at various points of the flue gas flow path. The results of the performance tests are used to ensure compliance with performance guarantees and emissions limits.

Contingency

Contingency accounts for unpredictable events and costs that could not be anticipated during the normal cost development of a project. Costs assumed to be included in the contingency cost category are items such as possible redesign and equipment modifications, errors in estimation, unforeseen weather-related delays, strikes and labor shortages, escalation increases in equipment costs, increases in labor costs, delays encountered in start-up, etc.

The EPA CCM cites contingency from 5 to 15 percent of the total capital investment (TCI) for "mature control technologies." However, the CCM acknowledges that "Contingency is inversely proportional to the level of accuracy for a cost estimate. A study-level cost estimate, which is the level of analysis accuracy for estimates arrived at using the Control Cost Methodology, will have a higher contingency as compared for a more accurate (20-percent probable error) cost estimate that was arrived at with a greater amount of data and effort."

This analysis is considered a conceptual level analysis; no detailed design was performed, and quantities are based on takeoffs from similar systems. In addition, current market conditions are such that significant changes are being seen in material and labor costs at this time. Therefore, a slightly higher contingency of 20 percent is justified.

Allowance for Funds Used During Construction (AFUDC)

AFUDC are not allowed by EPA's cost methodology and will not be considered further and will not be included in these cost estimates.

Site Specific Capital Cost Factors

This study developed a project specific estimate. The project specific estimate is based on site specific information and proposals resulting in a more accurate estimate. Where factors are used in the estimate, they are based on industry accepted standards (Lang/Guthrie factors) modified with information from B&V's database, which have been developed from projects B&V has estimated and executed. The factors include costs such as piping, steel, concrete, electrical (cable, conduit, cable tray), instrumentation, insulation, paint, and labor.

The Doyon cost analysis calculates that the erection cost will be 119 percent of the purchased equipment cost, compared to the EPA CCM default value of 40 percent. These cost factors result in construction/installation and indirect capital costs that are much higher as a proportion of PEC than other recent cost analysis projects the EPA has reviewed in Alaska, including the prior cost analyses submitted as part of the Fairbanks SIP.

In reviewing the differences there are several reasons that contribute to the cost discrepancy between the Doyon estimate and the EPA CCM approach. The following items are included in the Doyon/B&V estimate, that are not captured by the EPA CCM approach to estimating (based on the B&V review of Section 1.3.3.2 of the EPA CCM):

1. Adjustments for Alaskan wage rates
2. Adjustments for Alaskan labor productivity
3. Interconnecting duct work and supports
4. Electrical equipment
5. New common stack
6. Construction Management & Startup costs are based on staff count and duration
7. Buildings are sized and priced on a $/SF basis

Material and installation for items such as engineering, inter-connecting pipe racks, piling, buildings, electrical power distribution systems, are based on determined bills of quantities. The hours used to determine the installation costs are based on actual hours required on previous projects and adjusted for Alaskan productivity rates. Below are additional details on why Doyon's cost estimate differs from the EPA CCM:

- Wage Rates

  The TIC Factors that are used in the B&V estimate reflect US Gulf Coast (USGC) craft labor costs. In order to make the estimate region-specific, it is necessary to adjust the wage rates to reflect Alaskan costs. The average burdened wage rate (across all major craft classifications) for the USGC is approximately [redacted] per hour. This was adjusted to reflect the state average of [redacted] per hour, according to the Davis-Bacon hourly labor rates data for Alaska[8]. Further breakdown of all labor types included in this average is available in Appendix G.

[8] Davis-Bacon Prevailing Wage Rates for Alaska | https://sam.gov/wage-determination/AK20210001/4

- Labor Productivity

  The TIC Factors that are used in the B&V estimate reflect USGC labor productivity. The labor productivity in Alaska is significantly lower than USGC primarily for two reasons - labor availability and weather conditions. Based on the Compass International Global Construction Costs Yearbook[9], in conjunction with B&V experience, a Productivity Factor of 1.50 (50-percent less productive than USGC) was incorporated in the B&V estimate to reflect this lower productivity for the Alaska market.

- Construction Indirect Costs

  B&V calculates Construction Indirect Costs (including scaffolding) as a percentage of Direct Labor Cost. Based on B&V project experience, this percentage typically ranges from approximately 80-percent (for non-union construction) to 100-percent (for union construction). Alaska is a heavy Union construction market; therefore the 100-percent rate was applied.

  - Interest Rates

  An interest rate of [redacted] percent is used for cost estimations, deviating from the default rate of 5 percent in the EPA CCM. This interest rate more accurately describes DU's deemed structure on total capitalization, typical for utilities. Under this structure, DU is financed with a combination of debt and equity. Debt includes short term bank debt (generally a 5-year facility) as well as long term notes (10 to 30 year) held by private investors, while equity includes investment by owners, whether shareholders of a corporation or members of an LLC. The interest rate is calculated as a weighted cost of capital (WACC) from the return percentages from both debt and equity. DU's utility privatization contracts with the government provide guidance related to the debt and equity financing structure as well as the allowed return on equity (ROE). The contract outlines General Financial Assumptions in J19-9 & J19-15:

    - *J19-9 "At the same time, inherent in Doyon Utilities price proposal to the Army is a 12.5% Return on Equity. Should Doyon Utilities Price Proposal beat the Army's costs, then as set forth in Doyon Utilities price proposal, the 12.5% will become a contractual term and a 12.5% rate of ROE and a 60% debt and 40% equity capital structure shall be incorporated in future rate filings and rates before the Regulatory Commission of Alaska."*

    - *J19-15 "The following are the key global financial/financing assumptions in the financial model and pricing proposal: • Long Term Capitalization Plan of Doyon Utilities, LLC shall be 60% Long-Term debt and 40% equity.*

  DU's contracted debt/equity ratio is 60 percent debt and 40 percent equity or 60/40. The debt return percent will vary based on the changing level of debt and the debt interest rate, but averages at 4.125 percent. The equity return percent is set by the return opportunity allowable in the contract at 12.5

[9] Compass 2021 Global Construction Costs | https://compassinternational.net/product/global-construction-costs/

percent. Weighting these two return percentages by the 60/40 ratio results in a WACC interest rate of [redacted] percent.

Table 2-4 DU Weighted Cost of Capital

WACC COMPONENT	DEBT/EQUITY RATIO	RETURN RATE %	WACC
Equity	[redacted]	[redacted]	[redacted]
Debt	[redacted]	[redacted]	[redacted]
AVERAGE WACC INTEREST RATE:			[redacted]

2.2.2 Annual Operating and Maintenance Costs Estimate

The costs of reagent, electric power, makeup water, wastewater, and byproduct disposal are variable annual costs and are dependent on the amount of pollutant removed. Operating and maintenance materials and labor are fixed annual costs that do not vary with these factors. Table 2-5 lists the major economic factors used to obtain annual operating and maintenance costs. The costs and factors were reviewed and agreed upon with Doyon Utilities.

Table 2-5 Economic Evaluation Factors (All Costs are in 2021$)

ECONOMIC FACTOR	UNIT	VALUE
Reagent Cost		
Limestone	$ / ton	[redacted]
Pebble Lime	$ / ton	[redacted]
Hydrated Lime	$ / ton	[redacted]
Sodium Bicarbonate	$ / ton	[redacted]
50% Solution of Sodium Hydroxide	$ / ton	[redacted]
Water Cost	$ / gal	[redacted]
Wastewater Disposal Cost	$ / 1,000 gal	[redacted]
Landfill Disposal Cost	$ / dry ton	[redacted]
Electric Power Cost	$ / kWh	[redacted]
Economic Plant Life	Years	[redacted]
Capital and O&M Escalation Factor	%	[redacted]
Capital Recovery Factor (annualize cap. cost)	%	[redacted]
Present Worth Discount	%	[redacted]
Interest Rate	%	[redacted]
Freight	% of Capital Cost	[redacted]
Contingency Cost	% of Installed Cost	[redacted]
Average Operator Labor Cost (per year)	$ / year	[redacted]

Reagent Costs

Reagent costs include the cost for the material and delivery to the facility. This study used budgetary costs for these reagents provided by the technology providers and reagent suppliers. Additional expenses such as mixing and preparation are not included in this category. Reagent costs are a function of the quantity of the reagent used and the price of the reagent and will vary with the quantity of pollutant that must be removed as well as the reagent utilization ratio for each control technology. Reagent costs were identified for the following reagents:

- Limestone Slurry – $CaCO_3$
- Pebble Lime – CaO
- Hydrated Lime – $Ca(OH)_2$
- Sodium Bicarbonate – $NaHCO_3$
- 50-percent Solution of Sodium Hydroxide – NaOH

Electric Power Costs

Additional auxiliary power will be required to run the new control technology systems applied to the facility. The power requirements vary depending on the type of technology and the complexity of the system. Additional power is also required to run the ID or booster fan to make up for the flue gas pressure losses through the new scrubber equipment. The additional power required for ID fan power was estimated with a basis of 90 percent fan efficiency and 80 percent motor efficiency.

This study used a value of [redacted]/kWh for electric costs. This is based on the cost of electricity that is purchased ([redacted]/kWh) and generated ([redacted]/kWh) by DU. Based on past figures, DU predicts that [redacted] power for a new AQC system will be purchased and [redacted] will be from the power generated by the facility. This results in a total of [redacted]/kWh. See Table 5-5 and

Table 5-6 for further breakdown.

Makeup and Service Water Costs

Makeup water or service water is required for some of the processes in the new control technology systems. Examples of water consumption in the new control technologies are reagent preparation for limestone forced oxidation or lime-based scrubbers. There might be some variation in the quality of water required for these processes and this can be controlled using water treatment systems. The current cost of water to the CHPP was used in this study.

Wastewater and Byproduct Disposal Costs

Some control technologies generate wastewater and/or byproduct that will require disposal. For example, a wet flue gas desulfurization (WFGD) system generates a wastewater stream during blowdown to regulate the level of chlorides in the slurry recirculation system (water introduced into the CDS and SDA will exit the system through the flue gas, and water consumption for the DSI is solely with maintenance activities). Additionally, byproducts are formed when the limestone reacts with the SO_2 in the flue gas to form calcium sulfate and calcium sulfite. Although it may be possible to sell the byproducts from the WFGD as gypsum, it is assumed that the byproducts must be disposed as landfill. The byproducts generated by the DSI and SDA have no commercial use and requires disposal. The current cost for disposing of solids waste could not be truly determined, so the EPA CCM's general rate of [redacted] /ton was used in this study.

Operating Labor Costs

Operating labor costs are determined by estimating the number of employees that are required to run the new Air Quality Control (AQC) equipment. This estimation is based on industry common practices and is only a suggested quantity. Final determination of the staffing levels will need to be determined after the installation of control technology. The annual maintenance materials and labor costs were estimated per the EPA CCM based on a fully loaded labor rate with the basis of 40 hours per work week. Typically, a complex emissions control technology will require the following personnel:

- Supervisor
- Control Room Operator
- Roving Operator
- Relief Operator
- Laboratory Technicians
- Equipment Operators

Per Page 1-33 and 1-34 of the updated EPA CCM for SO_2 and Acid Gas Control, "In general, 16 additional full-time personnel are required to operate a wet FGD system for combustion unit greater than 500 MW (5,000 MMBtu/hour) and 12 additional full-time personnel for units equal to or less than 500 MW." For SDAs, on page 1-54 of the same document, "Generally, eight additional full-time personnel are required to operate an SDA FGD system."

To confirm the manpower requirements, Black & Veatch reached out to several clients that own and operate FGD systems. Three clients responded (all declined to have their identity disclosed), all of whom operate WFGDs. The most thorough information came from a facility that has multiple units less than 500 MW and with one WFGD per unit. Dividing the charged operating hours between the units, an average of slightly over 12 full-time employees was calculated, matching the EPA CCM's guidance. However, these numbers exclude contractor hours, which were substantial but difficult to separate for operating hours attributable to the WFGD. This client estimates that the contractor hours for the WFGDs would match the full-time employees' value, doubling the manpower the WFGDs require. However, twenty-four full-time employees is much more than the EPA CCM advises, and the CHPP is much smaller than this facility. Three WFGD vessels are included in this study's WFGD analysis. All three clients recommend having one full time operator in the control room throughout the day, which would mean three full time employees splitting three, eight-hour shifts. One full time employee is recommended per WFGD system, or three employees to operate the WFGDs during the primary hours of the working day. Two more full time employees should be planned for night shifts, for a total of eight full time employees to operate the WFGDs at CHPP.

There is less equipment associated with a caustic WFGD, as the lime slaking and gypsum handling system are not required. The number of control room operators between the WFGD and caustic WFGD should remain the same, but it's reasonable to expect that one operator could oversee all three caustic WFGD systems instead of the three recommended for a WFGD. Night shift operators are still recommended, so a total of six operators for the caustic WFGD systems is used in this study. Black & Veatch does not have any past or current clients that operate a caustic WFGD, so this value could not be verified from real-world applications.

The same logic for the WFGDs could apply to the SDA and CDS systems. All three of the technologies have reagent handling/preparation systems, reactor vessels, and solids handling systems. However, the EPA CCM recommends eight full time employees for an SDA system, and the CHPP is smaller in size compared to other utilities. [redacted] eight full time employees are reasonable, but considering the EPA CCM and the CHPP's size, six full time employees are used in this study for the SDA and CDS systems.

2.3 BASELINE EMISSIONS

The proposed operating scenario for [redacted] boilers is based on the cumulative coal combustion operating limit [redacted] per rolling 12-month period[10] and AP-42 Table 1.1-3 emission factors. [redacted] boilers firing a sub-bituminous coal. Per AP-42 Table 1.1-3, the SO_2 emission factor is 35*S lb/ton, where S is the weight percent sulfur content of the coal. The SIP limit as of June, 2021 limits the sulfur content of the coal to 0.25 weight percent or less, so the potential emission factor is 35 x 0.25 lb/ton-coal which equals 8.75 lb SO_2/ton-coal. The heat content of the [redacted] coal is 7,510 Btu/lb of coal, or 15.02 MMBtu/ton of coal[11]. The

[10] Technical Analysis Report of Permit AQ1121MSS04
[11] [(7,510 Btu/lb) x (2000 lb/ton) x (1 MMBtu/1,000,000 Btu)] = 15.02 MMBtu/ton

[redacted] boilers SO_2 emission rate is 0.58 lb SO_2/MMBtu[12]. The uncontrolled baseline emissions for SO_2 are required to be established in the BACT analysis for the comparisons of the various control technology options.

Table 2-6 Doyon Utilities [redacted] Boiler Design Basis

DESIGN BASIS	
Size (Main Steam Flow) per Boiler	[redacted]
Maximum Heat Input per Boiler	[redacted] MMBtu/hr
Coal Combustion Operating Limit (all boilers)	[redacted] (per rolling 12-month period)
Fuel	[redacted] Coal

Table 2-7 Doyon Utilities Baseline Emissions

BASELINE EMISSIONS	
EMISSION PARAMETER	EMISSION LEVEL
SO_2 Emission Factor (lb/ton of coal)	8.75
SO_2 Emissions for all [redacted] (tons/yr)	[redacted]

[12] [(8.75 lb SO_2/ton-coal) / (15.02 MMBtu/ton-coal)] = 0.58 lb SO_2/MMBtu

3.0 Identification of Available Control Technologies (Step 1)

The first activity of the BACT analysis methodology is to identify all available retrofit control technologies. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission unit and the SO_2 emission limit that is being evaluated. Technologies that have been successfully applied to similar sources or with similar gas stream characteristics shall also be considered as available. However, technologies that have not been applied to full or commercial scale operations are not considered to be available. If the source is equipped with existing control technologies, control options should include improvements or optimization of the existing control technologies. The SO_2 control technologies that were identified as available for retrofit at the CHPP (which the first three are considered the most stringent SO_2 control technologies) are listed below with a short summary of each technology in the following sub-sections:

- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (SDA)
- Dry Flue Gas Desulfurization (CDS)
- Duct Reagent Injection -- Dry Sorbent Injection (DSI)

3.1 WET FLUE GAS DESULFURIZATION

3.1.1 Limestone Wet Scrubber

Although wet lime and ammonia FGD systems are available, wet limestone FGD processes is the most frequently applied FGD technology in the US when treating flue gas from combustion of medium- and high-sulfur coals (typically greater than 1.5 percent sulfur). Wet limestone FGD systems are also applicable for units burning low-sulfur bituminous and subbituminous coals but the economics typically favor the semi-dry lime FGD systems. However, wet limestone FGD systems can achieve higher SO_2 removal than semi-dry lime FGD systems. A typical wet limestone FGD system consists of reagent storage and handling system, FGD spray tower absorber and byproduct dewatering system as illustrated in Figure 3-1.

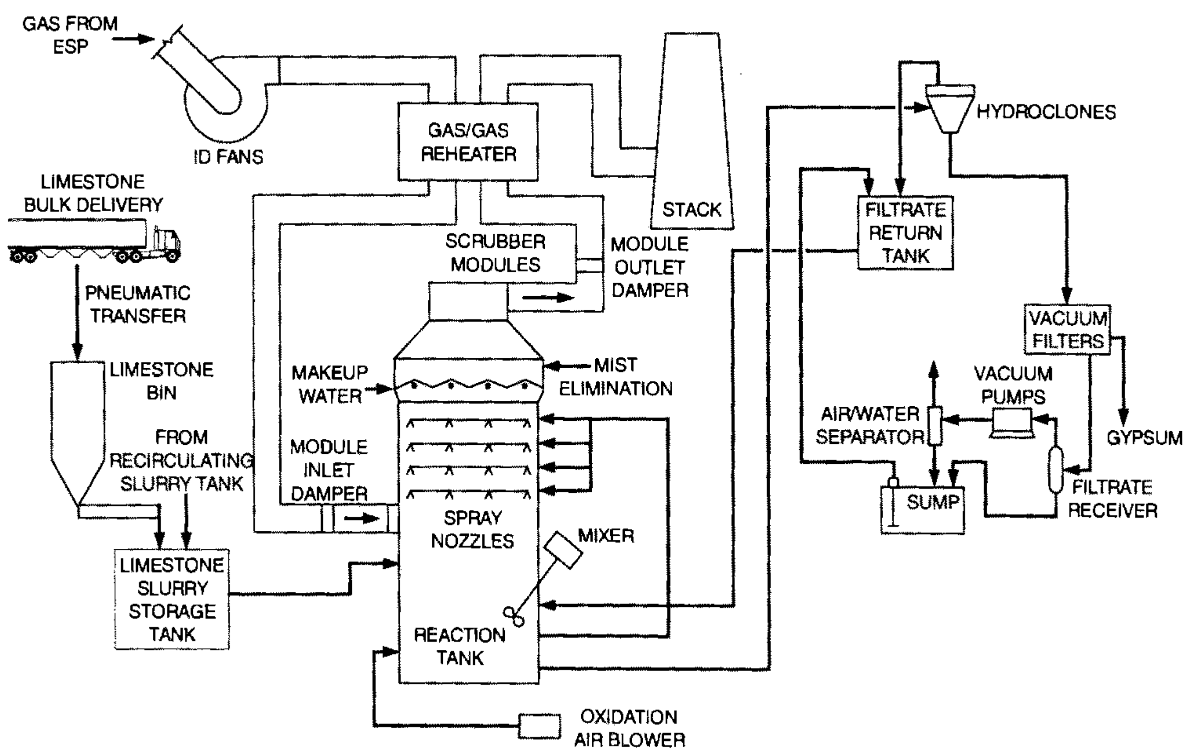

Image Source : Kentucky Public Service Commission 20110616 Appendix D | http://www.psc.ky.gov/PSCSCF/2011%20cases/2011-00161

Figure 3-1 Standard Layout of Spray Tower Wet FGD System

For most wet limestone FGD applications, the absorber module is located downstream of the Induced Draft (ID) fans (or booster ID fans, if required). If flue gas bypass or reheat is applied, the ID or ID booster fans could be located downstream of the FGD absorber module. For a wet FGD system, the flue gas enters the absorber and is contacted with a slurry containing reagent and byproduct solids. The SO_2 is absorbed into the slurry and reacts with the calcium to form $CaSO_3 \bullet 1/2H_2O$ and $CaSO_4 \bullet 2H_2O$.

There are several types of absorber modules, and each has characteristic advantages and disadvantages. FGD equipment vendors have specific designs for one or more types, and all compete on a capital/operating cost and guarantee basis. Depending on the process vendor, the absorber may be a co-current or countercurrent spray tower, with or without internal packing or trays. Other vendors use a unique absorber where the flue gas is bubbled into a reaction tank as illustrated in Figure 3-2. Regardless of the type of absorber used, the flue gas leaving the absorber is saturated with water and the stack will have a visible, persistent moisture plume. Generally, wet FGD systems do not remove significant quantities of SO_3 from the flue gas. Condensed SO_3, in the form of sulfuric acid mist, can be removed with a wet electrostatic precipitator (ESP).

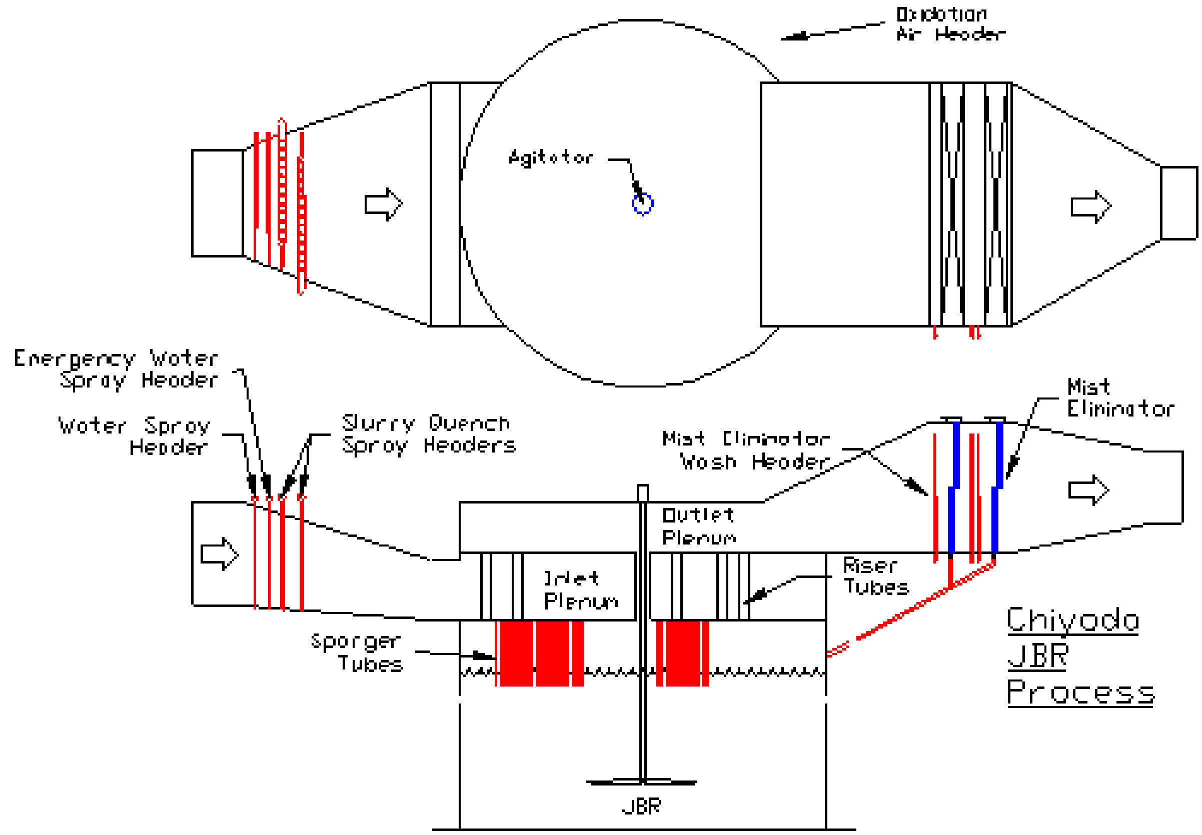

Image Source : Chiyoda Corporation

Figure 3-2 Cutaway View of a Jet Bubbling Reactor Wet FGD System

Because of the chlorides present in the mist carryover from the absorber and the pools of low pH condensate that can develop, the conditions downstream of the absorber are highly corrosive to most materials of construction. Highly corrosion-resistant materials are required for the downstream ductwork and for the stack flue. Careful design of the stack is needed to prevent "rainout" from condensation that occurs in the downstream ductwork and stack.

The reaction byproducts are typically dewatered by a combination of hydro-cyclones and vacuum filters. For natural oxidation wet limestone FGD systems, the resulting filter cake is suitable for landfill disposal. In some instances, the FGD byproduct requires mixing with fly ash and/or lime (fixation) to produce a physically stable material.

If air is bubbled through the reaction tank, practically all the $CaSO_3 \bullet 1/2H_2O$ can be converted to $CaSO_4 \bullet 2H_2O$, which is commonly known as gypsum. This oxidation step is termed "forced oxidation." Compared to calcium sulfite, gypsum has much superior dewatering and physical properties, and forced-oxidized systems tend to have few scaling problems in the absorber and mist eliminators. Dewatered gypsum can be landfilled without stabilization or fixation. Many wet FGD systems in the US are using the forced-oxidation process to produce commercial grade gypsum that can be used in the production of Portland cement or wallboard. Marketing of the gypsum can eliminate or greatly reduce the need to landfill FGD byproducts.

The wet FGD processes are characterized by high efficiency (typically between 92 to 98 percent) and high reagent utilization (95 to 97 percent). The absorber vessels are fabricated from corrosion-resistant materials such as epoxy/vinylester-lined carbon steel, rubber-lined carbon steel, stainless steel, or fiberglass. The absorbers handle large volumes of abrasive slurries. The reagent handling and byproduct dewatering equipment is also relatively complex and expensive. These factors result in relatively higher initial capital costs and lower annual operating costs compared to the semi-dry FGD alternatives.

3.1.2 Caustic Wet Scrubber

For smaller units such as the CHPP, a caustic based WFGD system may be considered. The base technology of the wet spray tower is identical, but with the substitution of caustic NaOH solution for the lime slurry. Caustic soda is more reactive than limestone and does not require the expensive equipment or the footprint of the limestone grinding, oxidation of the absorber, or dewatering systems to operate. The major pieces of equipment of the caustic wet scrubber are the absorber, make-up water pump, NaOH pump, mist eliminator, spray level(s), and storage tank. The reagent cost of NaOH is greater than limestone, but for small systems, the reduced complexity and associated installation and maintenance costs make up for this difference.

The typical concentration of caustic soda is 50 percent by weight, which has a notably high freezing point of 54 °F. This requires extensive heat tracing or HVAC support for most plant locations, particularly in Alaska. Additional considerations must be given for reagent supply and preparation. To avoid freezing en-route, NaOH will likely have to be supplied in a solid granular or pebble form to be dissolved on-site.

3.2 SPRAY DRY ABSORBER

The Semi-Dry FGD process is based on the spray drying of lime slurry into flue gas. This is performed in a Spray Dryer Absorber (SDA). There are numerous SDA FGD system installations on boilers using low-sulfur fuels. These installations, primarily located in the western US, use either lignite or sub-bituminous coals as boiler fuel and generally have spray dryer systems designed for a maximum fuel sulfur content of less than 2 percent.

There are several variations of this process, but the most prevalent is the installation of one or more spray dry vessels upstream of a supplied particulate control device as shown in Figure 3-3. The SDA absorber vessel is located between the air heater and the particulate removal device, most commonly a pulse jet fabric filter (PJFF).

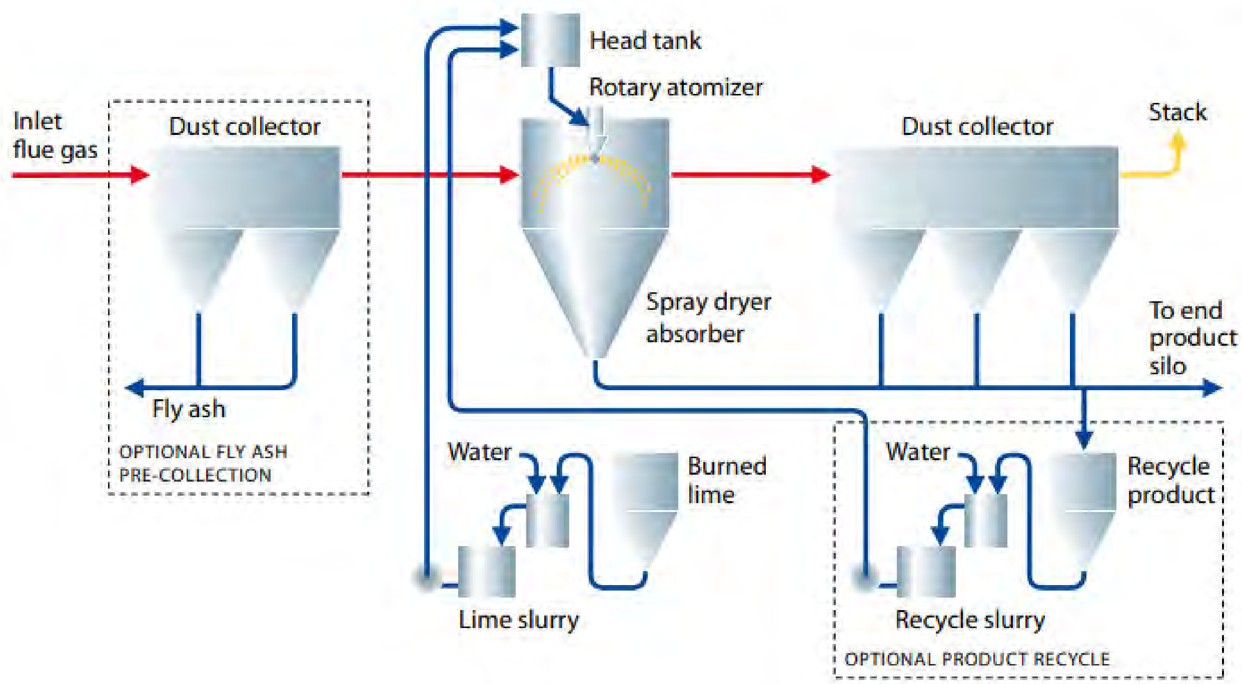

Image Source : GEA Process Engineering | https://www.gea.com/en/binaries/flue-gas-cleaning-spray-power-plants-gea_tcm11-34871.pdf

Figure 3-3 Standard SDA FGD System Layout

Although either quicklime slurry (CaO) or a sodium carbonate (soda ash) solution may be used as the scrubbing reagent, the current generation of SDA FGD processes uses primarily quicklime. The quicklime is first slaked with water to form a calcium hydroxide ($Ca(OH)_2$) slurry. The lime slurry is combined with the recycled solids from the PJFF to form the reagent slurry. The reagent slurry is injected in the absorber using either a rotary or dual-fluid atomizer, where the lime reacts with the SO_2 in the flue gas. Sufficient water is added with the reagent slurry to lower the flue gas temperature to within 18°C (32°F) of the adiabatic saturation temperature. The SO_2 is absorbed into the fine spray droplets and reacts with the lime slurry to form both calcium sulfite (~1/3) and calcium sulfate (~2/3). Before the droplet can reach the wall of the atomizer, the heat of the flue gas evaporates the droplet to a dry particle containing the byproduct solids and excess reagent. As the reagent slurry evaporates, a relatively dry powder remains.

The byproduct solids and fly ash are collected in the PJFF. The PJFF is always supplied as a system along with the SDA. The PJFF is an active component of the SO_2 removal system as a percentage of removal occurs as the flue gas passes through the dust cake on the bags. The vendor guarantee is based upon the total removal as measured at the exit of the PJFF. The byproducts and fly ash are conveyed pneumatically to the fly ash silo in the conventional manner. These solids are unloaded, conditioned with water, and transported to a landfill. Because of the level of free lime in the byproduct solids, the byproduct/fly ash mixture attains a very high bearing strength and low permeability in the landfill. Unlike a wet limestone FGD system, there is currently no commercial use for the byproduct/fly ash.

3.3 CIRCULATING DRY SCRUBBER

A Circulating Dry Scrubber is a form of Dry FGD for SO_2 removal. This technology is capable of removing 95 to 98 percent of the SO_2 in the flue gas. Hydrated lime ($Ca[OH]_2$) is the reagent used and is introduced as a dry, free flowing powder into the scrubber vessel. Flue gas is then flowed through the lime reagent in a circulation pattern for adsorption of SO_2 by the lime. A schematic of the process flow of a CDS process is shown in Figure 3-4.

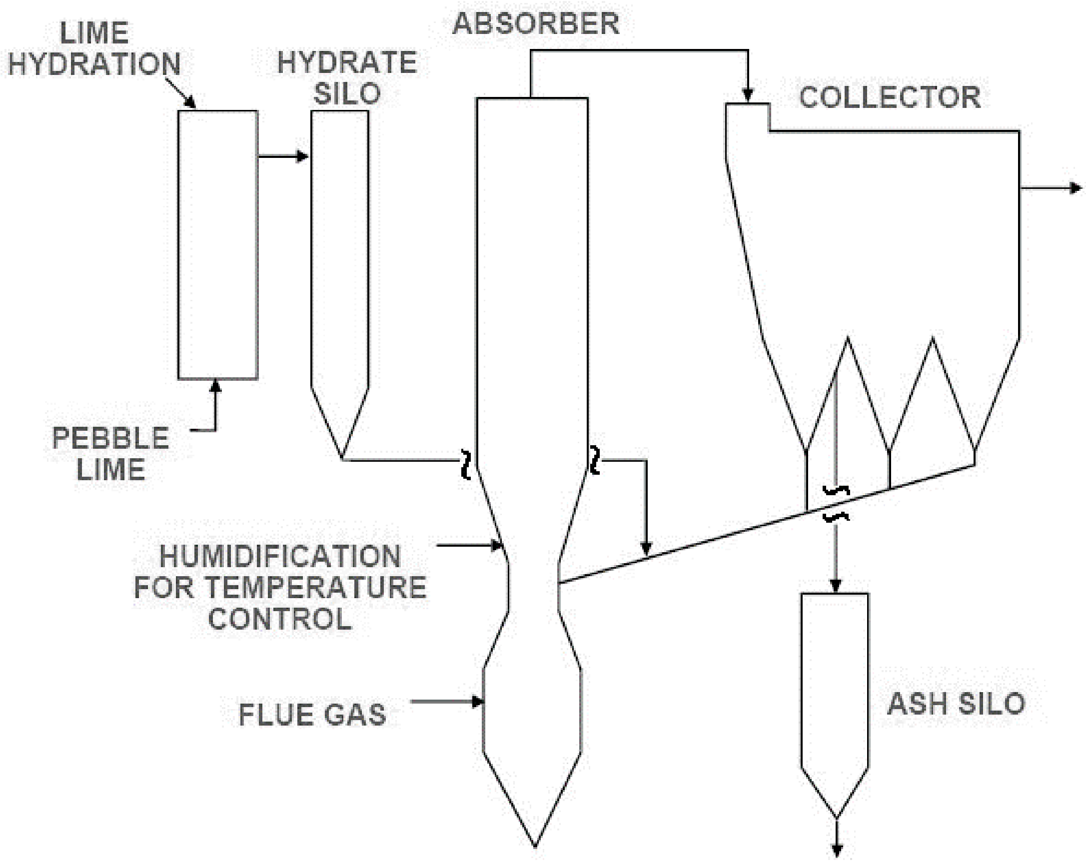

Image Source : Lurgi Lenties North America

Figure 3-4 Standard Circulating Dry Scrubber System Layout

Generally, there are no constraints on the maximum fuel sulfur content, as the CDS can be adjusted to account for the higher SO_2 loading by increasing the concentration of reagent. However, this flexibility is limited by the cost of the lime reagent. An evaluation on the overall reagent cost is important before selecting this technology. Lime utilization is improved by cooling the flue gas before it reacts with the lime. Flue gas coming into the scrubber vessel is cooled to about 30° F above the adiabatic saturation temperature.

As is the case with the SDA, a downstream particulate collection device is required, usually an ESP or fabric filter (FF) for the removal of particulate matter from the ash in the coal and the product of the reaction of lime with the SO_2 in the flue gas. Because of the relatively high velocity of the flue gas through the scrubber vessel (approximately 19 ft/s), the treated flue gas carries entrained reagent and reaction products from the module to the downstream particulate control device. Depending on the CDS design, pre-existing ESPs or FFs may be able to facilitate the additional load.

Over 90 percent of the collected solids in the FF contain unreacted lime. Due to abrasion and impacts of the other particles in the flue gas as well as materials handling dynamics, the "shell" of reaction products on the reagent particles is broken up. This material is recycled into the scrubber vessel to further improve lime utilization. This solids recirculation also maintains the bed densities needed for contact and removal of SO_2. Typically, reagent is recirculated 35 to 50 times, providing a residence time of 30 minutes or more. Collected solids, which are not recirculated, will be disposed.

CDS systems typically cannot operate below 60 percent design volumetric flowrate. To achieve low turndowns such as the 10:1 turndown required to support the resilience and reliability needs of the strategically significant Army installation, flue gas recirculation (FGR) may be used. Clean gas is reintroduced to the scrubber inlet by the control of a recirculation damper so that the flowrate is always above the minimum requirement. The greater the recirculation, the colder the gas at the inlet of the CDS. If it gets too low, the flue gas can be heated by a steam coil or similar, to maintain proper design temperature. This is known as heated flue gas recirculation.

The CDS is a small vessel in an elevated location because flue gas travels upwards in a CDS vessel. This results in a smaller footprint for applications with space constraints. However, depending on the site situation, the retrofit of such a system might be costly especially if there are substantial construction and structural difficulties.

Disadvantages of this process include high dust loading at the particulate removal system and lack of US utility operating experience. Higher fabric filter pressure drops are encountered because of the flue gas dust loading and may need to be considered when retrofitting a CDS to a pre-existing system. CDS systems require recirculation from the downstream PJFF and this requires the PJFF to be equipped with a trough hopper system. The air-to-cloth ratio of the PJFF is higher for a CDS application due to the increased solids from the recirculation system. The PJFF must be elevated to facilitate the trough hopper system. The dust recirculation system consists of air slides which transports the dust and unreacted hydrated lime directly from the PJFF hoppers to the re-injection point of the hydrated lime. These modifications and additional equipment add to the overall cost of the CDS system.

3.4 DUCT REAGENT INJECTION

3.4.1 Dry Sorbent Injection

A potential lower-efficiency, low capital cost SO_2 control option is a dry sorbent injection (DSI) system. The control technology requires either a wet or dry reagent such as sodium carbonate, sodium bicarbonate, powdered lime, lime slurry, or hydrated lime. This technology is typically capable of removing between 20 to 50 percent of the SO_2 in the flue gas and its removal efficiency is highly dependent on the application, primarily the configuration of the existing ductwork and the flue gas residence time in the ductwork.

Typically, based on the type of reaction, temperature, percentage reduction rate and the corresponding retention time requirements, a dry reagent such as powdered lime and hydrated lime or a wet reagent such as lime slurry, sodium bicarbonate (SBC) or magnesium hydroxide are used. The use of a wet reagent for duct injection is preferred over a dry reagent due to the elevated gas temperatures that exist during normal operating conditions. The use of a wet reagent helps reduce the gas temperature and eliminates the need for additional ID booster fans for draft control.

DSI has been used to remove a variety of acids from flue gas, including hydrochloric acid (HCl), SO_2, and sulfur trioxide (SO_3). DSI systems are most effective when targeting SO_3 or HCl emissions, and while there are some installations intended for SO_2 removal, most are used to lower SO_3 or HCl emissions.

DSI systems inject a reagent directly into flue gas ductwork to absorb its targeted pollutant. When used for SO_2 removal, sodium-based sorbents such as SBC or Trona are typically used, because excessive amounts of hydrated lime are required to obtain the necessary levels of SO_2 removal. While cheaper than sodium-based sorbents, the elevated consumption rates of hydrated lime lead to larger storages silos, rotary feeders, etc. This results in a more expensive system in terms of up-front capital and annual operating costs. The same can be said when comparing Trona and SBC, because while cheaper than SBC, more Trona is needed to achieve equivalent SO_2 removal rates. Therefore, this study focused on SBC and Trona, with SBC being the ultimate basis for design.

The reagent is typically trucked or railed onto the site, where it is unloaded and held in a storage silo. From the silo, it is pneumatically conveyed to the injection points, where the reagent flows through lances into the flue gas stream. The lances are typically a carbon steel pipe with a proprietary design, depending on the system provider. Design considerations must be evaluated to determine where the reagent is injected. For example, if a system is using PAC for mercury control, the DSI's injection points should occur upstream of a PAC's injection points, because SO_3 is an inhibitor of PAC adsorbing mercury. Additionally, since DSI may contribute a significant addition to the dust loading, DSI should always be upstream of adequate particulate removal devices.

For sodium-based sorbents, DSI systems come with the option to mill the reagent. Milling reduces the reagent's particle size, which effectively increases the surface area for reactions to occur. Milling can occur in-line or prior to conveying, but rat-holing and other problems can occur if milled reagent is stored. Although it varies with sorbent type, vendors state that up to 50 percent less sorbent is used to achieve similar removal rates when milled.

Once milled, most of the DSI's chemical reactions occur in-flight, or in the flue gas as it travels through the ductwork. Adequate residence time (about 1 second, depending on the installation) is recommended to allow for chemical processes to occur. Some residual reactions occur in the particulate control device, as acid gases continue to pass over unreacted sorbent particles. This effect is more pronounced with baghouses/fabric filters than an ESP, because flue gas is forced to pass through a filter cake containing unreacted sorbent. The CHPP's PJFF therefore is a potential benefit for removing acid gases. Figure 3-5 shows a general diagram of the major equipment and streams for a DSI process at a facility.

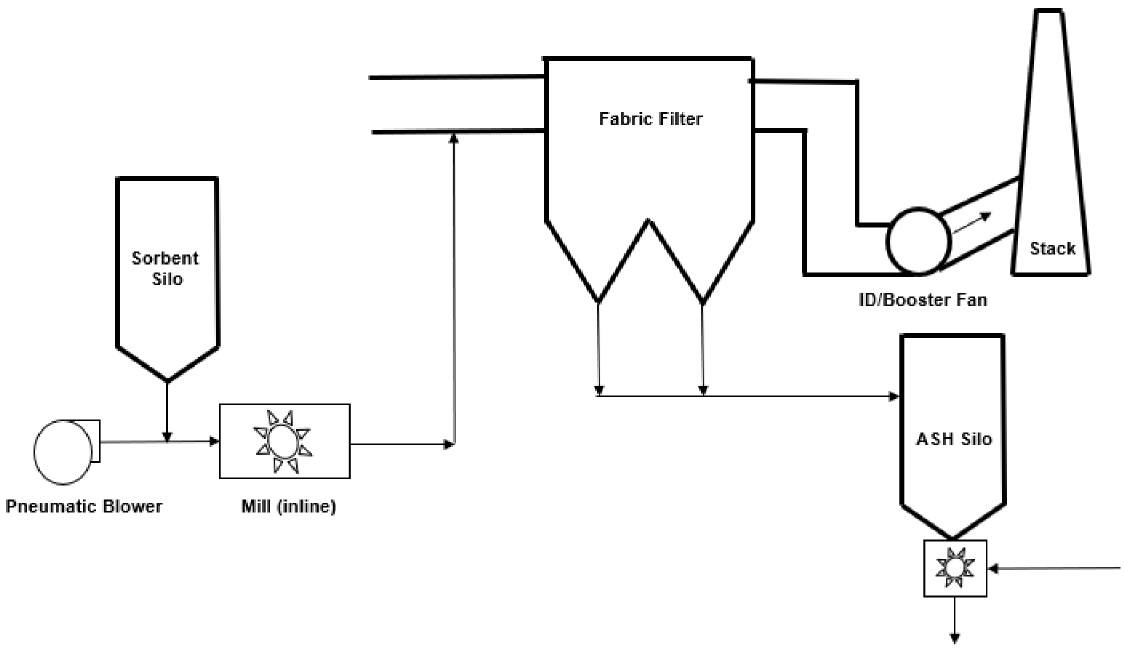

Image Source : Black & Veatch

Figure 3-5 Standard DSI System Layout

A design concern that is pertinent to the CHPP is the flue gas temperature at the injection point. Generally, when using sodium sorbents, greater temperatures yield better performance. The optimal temperature is between 275° F and 650° F. This is due to two primary factors. First, sodium reagents such as SBC and Trona rapidly calcine at temperatures above 275° F, going through a violent eruption of the particles' structure to expose more surface area for reactions with acid gases. Secondly, the reactions between sodium carbonate and SO_2 have a higher rate of reaction at higher temperatures. The benefits of hotter temperatures are only observed up to around 650° F, at which sodium particles start to soften and lose their porosity. Fewer pores correspond to less surface area for particles to react with SO_2, which leads to decreased removal rates.

4.0 Eliminate Technically Infeasible Options (Step 2)

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology.

A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage / research and patenting) and testing stages (bench scale / laboratory testing / pilot scale testing) are classified as not available. The commercially available technology is applicable if it has been previously installed and operated at a similar type of source of comparable size, or a source with similar gas stream characteristics.

Technically feasible retrofit emission control technologies are identified by eliminating technically infeasible options. The technologies identified in Section 3.0 are considered available technologies at the issue of this report. The available technologies are then screened to determine if they are technically feasible for application at the source.

In the process of eliminating technically infeasible alternatives, a demonstration is required to show that a technology is not available or not applicable for application at the source. This demonstration is performed when it can be shown that the technology is commercially unavailable and/or there are irresolvable technical difficulties with applying the technology. Other issues that determine the technical feasibility of a technology include:

- Size of the unit.
- Location of the proposed site.
- Operating problems after retrofit of technology.
- Space constraints.
- Reliability.
- Adverse effects on the rest of the facility.
- Adverse community impacts.

Additionally, a technology is technically infeasible if its level of emissions control does not achieve the required limit for the permit that is applicable to the source. Lastly, if there are multiple control technologies that have equivalent level of control, the BACT procedure allows for the consideration of the less costly control technology, therefore eliminating the need to evaluate additional, similar technologies. All the SO_2 control technologies that were identified as available for retrofit at Doyon Utilities[redacted] were determined to be technically feasible. Therefore, none of SO_2 control technologies were eliminated from the analysis.

4.1 BUDGETARY QUOTE REVIEW

The Design Basis was presented to six SO_2 scrubber system providers in order to get budgetary quotes and equipment sizes. The request asked for an analysis of the current system using WFGD, SDA, and CDS as a control technology and to look for opportunities to reuse the existing PJFF building if possible. As previously discussed in Section 3.3, CDS's cannot reuse the existing PJFF. The air-to-cloth ratio of the existing PJFFs is too low for downstream of the CDS application. CDS systems also require solids recirculation from the downstream PJFF and this requires the PJFF to be equipped with a trough hopper or recycle hopper. The PJFF must be elevated to facilitate the hopper system; therefore, the existing PJFF systems, located at grade, cannot be retrofitted with trough hoppers or recycle hoppers. This adds a significant cost to the CDS control technology with a new PJFF included.

The designs were to provide ample turndown capabilities to support [redacted] boilers operating at 10 to 100 percent MCR load. Proposals were returned from four of the six vendors. Black & Veatch has worked with two of the vendors on previous projects and considers all four as reputable suppliers with proven experience in the field. Three were chosen to compare: Andritz, B&W Environmental, and Tri-Mer. The fourth proposal not included was presented by LDX Solutions; this proposal only provided estimates for the CDS technology and used a combined header between [redacted] boilers to a common system. This design was too dissimilar from the remaining three vendors to compare and did not meet the specifications agreed with DU for turn-down and reliability. Further discussions with LDX also indicated this technology has not previously been utilized in this configuration. Since this would be a "First of a Kind" (FOAK) technology and has not been demonstrated in practice, this was not evaluated further.

For circulating dry scrubbers (CDS), Tri-Mer provided an alternative design approach and cost estimate based on utilizing the existing baghouse (as opposed to installing a new baghouse). The vendor estimate for this control option was approximately one third the capital cost of a CDS when a new baghouse is included.

A key consideration in the cost evaluation of a new emission control system is whether the existing baghouse can be reused, or if the design necessitates the installation of a new filtration system. The existing system baghouse is a pulsed jet fabric filter (PJFF) design with five parallel modules, and a design gross air-to-cloth (A/C) ratio of 4.0 $(ft^3/min)/ft^2$ and a net A/C ratio of 5.0 $(ft^3/min)/ft^2$. It is located between [redacted] boilers and the proposed location across the road for the installation of a new emissions control system.

A new CDS cannot reuse the existing pulsed jet fabric filter (PJFF) baghouse for two reasons. First, a CDS system generates additional particulate loading which the existing baghouse is not equipped to handle. CDS units should be operated with a much lower A/C ratio to provide greater filter surface area for the increased particulate loading per volume of air. If this design is not improved, high filtering rates would result in premature bag degradation, increased pressure drop, reduced efficiency, and filter blinding. Based on the proposals provided by Andritz and LDX Solutions (Tri-Mer and B&W did not provide specific baghouse analysis), the recommended gross and net A/C ratios should be 2.4 and 3.2 $(ft^3/min)/ft^2$ respectively— nearly half of the currently installed A/C ratios.

Secondly, CDS systems cannot use the existing baghouse because the reactor vessel requires solids recirculation from the downstream baghouse. In order to facilitate solids recirculation, the baghouse must be elevated and equipped with a trough or recycle hopper and air slides. The existing baghouse systems, located at grade, cannot be retrofitted with trough or recycle hoppers and the hopper entry does not provide adequate distribution of the combined volumes of fly ash and reagent. Thus, a new baghouse system must be included in the CDS design with a recycle system installed.

In their proposal, Tri-Mer provided two alternative CDS process designs: a recirculating dry scrubber (RDS), and a pneumatic circulating dry scrubber (pCDS). Their RDS technology represents the more traditional process with a single reactor tower and solids recirculation via air slides and a raised baghouse. Conversely, Tri-Mer's pCDS option was significantly different from industry-standard CDS installations proposed by other vendors. While the reactor vessel is similar, this design uses pneumatic conveyance to transport the collected dust from the baghouse to a buffer vessel, and from the buffer vessel to the injection point of two parallel reactors.

There are concerns that the use of pneumatic conveyance could lead to dust drop out in the long ducts and plugging of the solids recirculation system. The risk of plugging may be exacerbated by the need to transport the dust up and over the existing baghouse to reach the desired reactor installation location across the road. The potential for pluggage limits the reliability of the system.

Black & Veatch queried Tri-Mer to learn more about previous installations by the company using this approach. According to their reference list, their alternative pCDS technology has only been installed at one similar coal-fired boiler facility in the US. The system was an EPRI funded retrofit project for Multiple Air Pollutants (SOx, NOx, Hg) installed on an existing slip-stream at the Gadsden Plant in Alabama. A number of liquid reagents were sprayed in an injection point upstream of a baghouse, and hydrated lime was continuously recirculated from the baghouse hopper back to the injection point. Given the description of this design, the Gadsden reference is dissimilar to the system proposed for the CHPP. In their proposal for the pCDS system, Tri-Mer includes reactor vessels with a buffer silo and ductwork. There would be several bends and turns in the ductwork due to equipment configuration (the pCDS would be located across the street from the existing baghouse), and the duct runs would be [redacted] leading back to the existing baghouse. The significant increase in conveying distance and complexity presents a risk compared to Tri-Mer's existing project experience. While the Gadsden system was installed on a slipstream, the CHPP system [redacted]. In the case of a failure, the Gadsden system could continue operation, while the CHPP design would necessitate taking the connected boiler out-of-service. In addition, the Gadsden Plant no longer combusts coal. The Gadsden Plant was re-permitted to switch the coal-fired boilers over to natural gas approximately four years ago[13]. Gadsden is not required to use CDS to control SO_2 emissions. DU is hesitant to even consider pCDS an available control technology, because this technology was only installed on one similar facility that no longer uses it. The pCDS is not considered technically feasible. Given the

[13] Transmission Hub - https://www.transmissionhub.com/articles/2017/01/alabama-power-re-permits-coal-less-gadsden-power-plant.html

significant differences in design from Tri-Mer's previous installations and a lack of supporting experience for the proposed design, Tri-Mer's pCDS is not considered further for the CHPP. Only Tri-Mer's RDS technology will be considered in subsequent analysis.

The equipment costs from each vendor's budgetary proposal are summarized in Table 4-1. Technologies not supplied by the vendor are left blank. The average DSI equipment estimates from UCC and BACT contacted in a previous study are provided as a comparison.

For caustic WFGD, the capital cost by Tri-Mer differs from that shown in their proposal. Tri-Mer's first budgetary proposal quoted an amount for the caustic soda wet scrubber (CSWS) of [redacted] per boiler, or [redacted] total. Due to timing constraints, this proposal scope did not include the [redacted] interconnecting ductwork that would be required for the caustic WFGD to be located across the street of the current baghouse (the only feasible location identified for location of new equipment), ID fans, and motor VFDs needed to account for the added pressure drop of new equipment and ductwork, or the final stack.

In follow-up discussions with Tri-Mer, their representatives stated the ductwork and stack would be approximately [redacted] for each technology but could not yet provide an estimate for the ID fans and motor. Lacking a direct value from Tri-Mer, their quote was supplemented with the breakout cost of [redacted] provided by a different vendor (Andritz's quote provided this cost as a breakout). The stated value in the cost estimate from the report is thus [redacted] (the total of [redacted]).

Tri-Mer ultimately provided a revised proposal for their CDS and WFGD technologies with ductwork, but the WFGD design still did not include the cost for the ID fans and motor VFDs. Due to the uncertain status of the proposal, Black & Veatch followed up with Tri-Mer to receive additional breakout estimates and opted to use the original adjusted equipment costing estimate for the caustic scrubber ([redacted]) until all items were included.

Table 4-1 SO_2 Scrubber Equipment Costs from Vendors (All Costs are in 2021$)

VENDOR	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS	DSI
Andritz	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
B&W Env.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tri-Mer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
UCC & BACT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] The Caustic-WFGD quote from Tri-Mer was supplemented with breakout costs for ID fans, interconnecting ductwork, and a common stack as these items were not included in their proposal.

In meetings with the EPA as this study was developed, the EPA commented that the lowest vendor cost estimates should be used for the cost effectiveness analyses. The EPA did not feel there was a basis to question the veracity of any of the estimates provided, and the lowest cost estimates did not appear to be outliers compared to the other estimates.

Black & Veatch disagrees with the recommendation to use the lowest quote, due to the budgetary nature and variation between vendors' quotes. While there is no basis to question the veracity of any of the estimates provided, it is important to note that each quote was budgetary in nature. Even with official quotes based on formal RFQs, Black & Veatch has often received bids from suppliers that are missing items in their scope, and Black & Veatch will conduct a thorough evaluation and adjustment (as needed) of all bids to make their costs reflect equal scopes. The quotes developed by the vendors were not based on a complete specification and a thorough evaluation and equalization of the proposals was not performed. Due to the potential for inaccuracy in the budgetary proposals and the lack of time to fully equalize all bids, the use of an average value provides a more reliable value estimate that is expected to be more accurate.

The approach presented in this analysis is an appropriate method to develop a study-level cost estimate reflective of actual expected costs to the owner. Black & Veatch contends that this approach is not in conflict with the EPA CCM or other related documentation regarding cost estimates.

Further complicating the situation is that the low-price quote referred to in the EPA's comment (provided by Tri-Mer) is from a vendor that has little, demonstrated experience for their proposed technology. Per the New Source Workshop Manual for BACT analyses[14], a technically feasible technology must be both "available" and "applicable". An "available technology" is one that has reached "commercial availability" and "[may be] obtained by the applicant through commercial channels." While Tri-Mer's caustic scrubber is available, there are concerns with how applicable their system is to Doyon Utilities. The manual continues to address what is considered an "applicable technology":

> *"In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary."*

Tri-Mer's caustic scrubber has been demonstrated on only one coal-fired boiler, where 2,000 ACFM of flue gas was treated. Its largest installation is at a hospital waste facility, where 6,000 ACFM of flue gas was treated. The coal-fired boiler satisfies the requirement for the "same or similar source type," but there is a significant difference in the size of this installation and the Doyon facility. [redacted] which is over [redacted] times Tri-Mer's largest installation for a caustic scrubber and about [redacted] times larger than Tri-Mer's largest coal-fired installation. Scaling a project cost by this amount introduces a significant risk not

[14] NSR Workshop Manual | https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf

only in capital costs but also in operational costs and could be considered as not meeting the commercially available definition. It is unreasonable to only utilize the lowest bid for a cost evaluation. The reasonable method in determining the cost for a given control technology is to use an average of the bids.

Additional notes from the budgetary quotes include the following:

- All costs presented are controlling SO_2 emissions [redacted]
- Atomizer(s) in an SDA has significant implications on emissions; may need to consider triple atomizer vessel in the case of atomizer failure to stay within emission limits.
- WFGD is least sensitive to inlet temperature compared to other technologies.
- CDS may match WFGD emissions level (0.04 lb/MMBTU) at no additional capital cost by increasing the reagent usage.
- WFGD-Caustic and WFGD-Limestone are designed to have two boilers feed into one scrubber (based on turn down capabilities).
- SDA and CDS are designed to have one boiler feed into one scrubber.
- There is potential costs savings by combining multiple boiler trains to a single scrubber system, though a vessel failure could cause a plant outage.
- On page 2 of Babcock & Wilcox's budgetary proposal states that a lower cost CDS design could be developed where two or three boilers feed a single CDS while still allowing plant operation over the full load range. Doyon Utilities needs the operational capability and flexibility to run any of the boilers at any time at a turn down ratio of 10:1. SDA and CDS technology will not allow the flexibility required.

4.2 SUMMARY OF RETROFIT TECHNOLOGIES TECHNICAL FEASIBILITY

All of the SO_2 control technologies that were identified as available for retrofit at the CHPP were determined to be technically feasible. Therefore, none of SO_2 control technologies were eliminated from the analysis.

Table 4-2 Technically Feasible SO_2 Control Technologies

POLLUTANT	TECHNOLOGY	TECHNICALLY FEASIBLE AND APPLICABLE?
SO_2	Wet Flue Gas Desulfurization (WFGD)	Yes
	Spray Dry Absorber (SDA)	Yes
	Circulating Dry Scrubber (CDS)	Yes
	Dry Sorbent Injection (DSI)	Yes

5.0 Rank Remaining Control Technologies by Effectiveness (Step 3)

Step 3 of the BACT determination process is an evaluation of all the technically feasible control technologies which have been identified. A search of the information contained in the EPA BACT/LAER Clearinghouse was conducted to determine the top level of SO_2 control for coal-fired boilers of similar sized as Doyon Utilities (Industrial-Sized Boilers [redacted]). The results of this search for all coal fired boilers in the size range since 2005 indicated above did not provide any SO_2 BACT determinations. Therefore, the SO_2 technologies identified in Step 2 analysis will continue in determining the control effectiveness and cost effectiveness in the following sections.

5.1 CONTROL EFFECTIVENESS

The evaluation process in Step 3 determines the control effectiveness of each control technology. The control effectiveness is expressed in a common metric based upon the amount of pollutant generated per unit of heat input (lb/MMBtu). This evaluation of the control effectiveness is then translated into a yearly rate (ton/yr) for SO_2 based on the cumulative coal combustion operating limit [redacted] per 12-month period and AP-42 Table 1.1-3 emission factor with 0.25 weight percent coal sulfur content (SIP limit as of June 2021). The SO_2 emission factor calculated previously in Section 2.3 was 8.75 lb/ton of coal. The SO_2 emission factor and the coal combustion operating limit is used to calculate the total SO_2 emission per unit (tons/yr). Table 5-1 presents the design basis and the baseline SO_2 emissions.

Table 5-1 Design Basis and Baseline Emissions

DESIGN BASIS	
Coal Combustion Operating Limit (all boilers)	[redacted] (per rolling 12-month period)
BASELINE EMISSIONS	
Emission Parameter	**Emission Level**
SO_2 Emission Rate (lb/MMBtu)	0.58
SO_2 Emission Factor (lb/ton of coal)	8.75
SO_2 Emissions for all [redacted] (tons/yr)	[redacted]

Table 5-2 indicates the potential-to-emit (PTE) SO_2 emissions for each control technology, control effectiveness, SO_2 emissions removed, and removal efficiency. The control effectiveness ratings for each technology were selected from the averages of the top 20 and 50 percent U.S. coal-fired power plants according to the EPA CCM[15] and supported by vendor quotations. The PTE SO_2 emission rates for each control technology were calculated by multiplying the overall annual emission rate based on the cumulative coal consumption limit [redacted]

[15] EPA CCM, Section 5, Table 1.3

[redacted] by the fraction of uncontrolled emissions from the technology (100 percent minus the percent controlled). The percent-controlled parameter was calculated by subtracting the technology control effectiveness rating from the baseline emission rate (0.58 lb/MMBtu) and dividing by the baseline emission rate.

Table 5-2 Expected Performance of SO_2 Control Technologies [redacted]

CONTROL TECHNOLOGY	CONTROL EFFECTIVENESS (LB/MMBTU)	[redacted]	SO_2 EMISSIONS REMOVED (TONS/YR)	PERCENT CONTROLLED
Wet Flue Gas Desulfurization (WFGD) – Caustic	0.04	[redacted]	1,369.1	93.1
WFGD – Limestone	0.04	[redacted]	1,369.1	93.1
Spray Dry Absorber (SDA)	0.07	[redacted]	1,293.4	88.0
Circulating Dry Scrubber (CDS)	0.07	[redacted]	1,293.4	88.0
Dry Sorbent Injection (DSI)	0.12	[redacted]	1,167.2	79.4

The emission rate of 0.04 lb/MMBtu is equivalent to 93.1-percent removal. Control technologies have frequently demonstrated removal rates of well over 90 percent, but it would be erroneous to universally apply these reduction percentages. Eventually, there are insufficient amounts of SO_2 molecules in the flue gas to interact with the reagents used by control technologies. Thus, there is a floor to the pollution concentration that control technologies can achieve, and if a power plant starts with a low concentration to begin with (e.g., Doyon and other facilities that burn low-sulfur coal), the removal percentage will be lower.

Some control technologies, such as a WFGD and CDS have achieved removal rates upwards of 98 percent on units emitting high levels of SO_2. If a 98-percent SO_2 removal rate was applied to the CHPP's baseline emission rate, this would equal an SO_2 emission rate of 0.01 lb/MMBtu or lower depending on the actual sulfur content of the coal. The 0.01 lb/MMBtu emission rate is an unattainable mass emission rate, because it is lower than what desulfurization systems have been able to achieve on a consistent basis[16]. For example, Black & Veatch was involved in a project that installed a CDS on a unit burning Powder River Basin (PRB) coal, and stack testing to demonstrate the unit's initial compliance (occurred in 2018) resulted in a removal percentage of 91 percent. Upset conditions, startup, shutdown, and maintenance periods, and variability in fuel sulfur content further affect the ability to meet a 0.01 lb/MMBtu rate.

The caustic and limestone WFGD are the top control technology with 93.1 percent control, and an emission rate of 0.04 lb/MMBtu representing the most effective SO_2 emission control. The SDA and CDS are the second highest control technology with 88.0 percent control and an emission rate of 0.07 lb/MMBtu. While still offering significant removal, DSI represents the lowest control technology with 79.4 percent control and an emission rate of 0.12 lb/MMBtu. See Section 5.2.3 for

[16] Average of lowest 20-percent emission rates between 2016 and 2021 | https://ampd.epa.gov/ampd

further discussion on the emission rates used in this report and emission rates provided by SO_2 control technology vendors.

Table 5-3 summarizes the scope of supply for each technology and Table 5-4 provides the cost summary. The full cost estimate can be found in Appendix B.

Table 5-3 SO_2 Control "Purchased Equipment" Scope of Supply

SO_2 CONTROL TECHNOLOGY	PURCHASED EQUIPMENT SCOPE OF SUPPLY	
WFGD - Caustic	• Absorber towers • Reagent feed system: receiving, storage • Make up water pump, dampers • Chemical feed pump (NaOH) and recycle pump	• Mist eliminators and exhaust blowers • Flue gas handling: interconnecting ductwork • ID fans, Motors, VFDs • Taxes, Freight
WFGD - Limestone	• Absorber towers (tray, spray headers, mist eliminators) • Reagent feed system: receiving, storage • Absorber recirculation pumps and recirculating piping • Oxidation air blowers and injection lances • Reagent preparation system: silo, mills, pumps, and tanks	• Dewatering system: hydrocyclone, vacuum filter, pumps, etc. • Integral stack and pressure control inlet dampers • Flue gas handling: interconnecting ductwork • Fan modifications: [redacted]booster fans • ID fans, Motors, VFDs • Taxes, Freight
SDA	• Absorber vessels, including roof gas dispersers • Atomizers • Reagent preparation system: silo, slakers, pumps, and tanks	• Recycle system: silo, rotary feeders, pumps, and tanks • Interconnecting ductwork and new PJFF inlet manifolds • ID fans, Motors, VFDs • Taxes, Freight
CDS	• CDS vessels • Flue gas recirculation system • Humidification water system • Common fluidizing air system • Reagent prep systems: silo, rotary feeders, and convey air systems • Byproduct recirculation system: fluidization slides, rotary feeders, etc. • Common byproduct storage system, silo, rotary feeder, pug mill, etc.	• Interconnecting ductwork • [redacted]new PJFF systems, including casing • Compartment inlet/outlet dampers • Bags and cages • Pulse air headers and control system • New stacks • ID fans, Motors, VFDs • Taxes, Freight
DSI	• DSI system (blowers, silos, mills, lances) • Piping • Structural Steel	• Electrical equipment • Misc. equipment • Taxes, Freight

Table 5-4 Capital Cost Estimate Summary (All Costs are in 2021$)

CATEGORY	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS	DSI
Total Direct Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Purchased Equipment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Foundation & Supports	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Structural Steel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Handling & Erection	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Electrical	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Piping	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Insulation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Painting	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Instr. & Controls	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Site Preparation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Buildings	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New Wet Stack	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Indirect Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Engineering	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Construction & Field	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Start-up	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Performance Test	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contingencies	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

In addition to capital costs, annual operational and maintenance costs were developed. A capacity factor of 39 percent (based on heat input) was used in determining the annual costs. Direct annual costs include fixed costs, such as labor and maintenance, and variable annual costs, such as consumables like reagent. Two to ten full-time employees are assumed to be needed for the new scrubber system's operating labor, and maintenance costs follow the EPA CCM's recommendations for maintenance labor and materials.

Variable annual costs are predominantly driven by the cost of the selected reagent. Bulk reagent cost information is available in Table 2-5. Water and sewer costs are included at [redacted]/1,000 gallons and [redacted]/1,000 gallons per DU's information, respectively. Disposal costs for additional solids is assumed to be about [redacted]/ton based on the EPA CCM, but this value could increase if the FWA landfill is no longer available for the CHPP. As the CHPP facility is designed and operated to provide steam for the Army base, power generation is a secondary product at a comparatively more expensive unit cost. The average value of power generated at CHPP in 2020 was [redacted]/kWh, compared to the market price of [redacted]/kWh [redacted] a weighted average of [redacted]/kWh has been selected for electricity costs. Historical electricity generation and import costs are summarized in Table 5-5 and Table 5-6 Doyon Utilities accounting provided the O&M costs for station power only, removing all costs related to distribution heating. O&M costs include; labor, materials and supplies, contract supplies, taxes, and depreciation.

Table 5-5 Doyon Utilities 2020 Electricity and Steam Generation Summary

2020 CHPP INFORMATION	UNITS	VALUE	SOURCE
Station Expenses			
Total 2020 Coal Costs	$USD	[redacted]	2020 CHPP Energy Production Costs
Total 2020 Labor and O&M Costs	$USD	[redacted]	DU Accounting
Total 2020 Station Expenses	**$USD**	[redacted]	**2020 CHPP Energy Production Costs**
Steam-to-Post (STP) Generation			
Total 2020 STP	klbm	[redacted]	Monthly Operations Report
Average Fraction of Fuel to STP	%	52.9%	Hourly Historian Data
2020 Value of STP	$USD	[redacted]	2020 CHPP Energy Production Costs
2020 Average STP Unit Cost	$/klbm	[redacted]	2020 CHPP Energy Production Costs
Power Generation			
Total 2020 Power Generated	kWh	[redacted]	Monthly Operations Report
Average Fraction of Fuel to Power	%	47.1%	Hourly Historian Data
2020 Value of Power	$USD	[redacted]	2020 CHPP Energy Production Costs
2020 Average Power Unit Cost	$/kWh	[redacted]	2020 CHPP Energy Production Costs

Table 5-6 Doyon Utilities 2020 Electricity Import Costs Summary

UTILITY PERIOD MONTH	IMPORTED POWER MWH	BILLED UTILITY $ USD	CALCULATED ELECTRICITY RATE $/MWH	CALCULATED ELECTRICITY RATE $/KWH
January, 2020	2,310	[redacted]	[redacted]	[redacted]
February, 2020	2,380	[redacted]	[redacted]	[redacted]
March, 2020	1,890	[redacted]	[redacted]	[redacted]
April, 2020	2,240	[redacted]	[redacted]	[redacted]
May, 2020	3,290	[redacted]	[redacted]	[redacted]
June, 2020	3,150	[redacted]	[redacted]	[redacted]
July, 2020	2,870	[redacted]	[redacted]	[redacted]
August, 2020	3,570	[redacted]	[redacted]	[redacted]
September, 2020	2,030	[redacted]	[redacted]	[redacted]
October, 2020	3,150	[redacted]	[redacted]	[redacted]
November, 2020	2,730	[redacted]	[redacted]	[redacted]
December, 2020	3,290	[redacted]	[redacted]	[redacted]
Annual Total	**32,900**	[redacted]	[redacted]	[redacted]

The auxiliary and ID fan power consumption was estimated by vendors and used in this study. A new baghouse is needed for the CDS, so the power estimated by the vendors for a new CDS system needs to be corrected for the current power associated with the existing baghouse. The power associated with the pressure drop across the existing baghouse (around [redacted] per boiler) was subtracted from the vendors' estimates. The total reduction in auxiliary power across all six boiler systems is therefore [redacted] from the vendors' estimates.

Indirect costs include administrative costs and the cost for capital recovery. Both were calculated using guidance from the EPA CCM. The administrative cost was set to 2 percent of the TCI, and the capital recovery factor was determined with a lifetime of 30 years and an interest rate of [redacted] or the weighted average cost of capital (WACC). Doyon Utilities uses a deemed cost of total capitalization structure. The structure is based on 40 percent of capital being provided through equity and 60 percent of capital being provided through debt. The required equity return percent (12.5) is set by the return opportunity allowed in the contract. The debt return percent is set by the DU weighted average cost of debt and will vary based on what debt exists at what interest rate but averages to 4.125. With this capitalization structure, DU's weighted average cost of capital [redacted].

Table 5-7 summarizes the annual costs, with further breakout provided in Appendix B.

Table 5-7 Annual Costs Estimate Summary (All Costs are in 2021$)

CATEGORY	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS	DSI
Total Direct Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Op. / Support Labor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maintenance Labor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maintenance Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reagent	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Byproduct Disposal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aux. and ID Fan Power	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Water	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Indirect Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Administrative Charges	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost for Capital Recovery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Annual Cost (TAC)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

5.2 COST EFFECTIVENESS AND IMPACT ANALYSIS

5.2.1 Base Case Study

The cost effectiveness of each control technology is calculated from the cost of compliance and the amount of pollutant reduced. Two types of cost effectiveness are calculated: general and incremental cost effectiveness. General cost effectiveness describes the cost of a technology given its capacity to remove the target pollutant in terms of dollars per ton. Incremental cost effectiveness describes the relative cost to remove additional pollutant beyond the nearest neighbor below it on the least-cost envelope.

An impact analysis was performed for all the identified technically feasible control technologies at their expected after control emission levels and is summarized in Table 5-8. The cost effectiveness of each technology may be visualized in Figure 5-1, plotting the technology's Total Annualized Cost (TAC) versus the expected emissions reduction for all control alternatives identified in the BACT analysis.

Table 5-8 Impact Analysis and Cost Effectiveness – PTE Basis (All Costs are in 2021$)

ALL FEASIBLE TECHNOLOGIES	UNIT	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS + PJFF	DSI
Emission Performance Level	lb/MMBtu	0.04	0.04	0.07	0.07	0.12
[redacted]						
SO_2 Emission Removed	tons/yr	1,369.07	1,369.07	1,293.36	1,293.36	1,167.20
Capital Costs	1,000$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Annualized Cost	1,000$	17,046	17,343	20,090	23,488	5,793
Cost Effectiveness	$/ton SO_2	12,451	12,668	15,533	18,160	4,963
Incremental Cost Effectiveness	$/ton SO_2	55,744	57,215*	113,317*	140,250*	--

*Note: Only WFGD-Caustic and DSI are on the least-cost envelope; incremental analysis is shown for reference only

From the graphical plot, a "least-cost envelope" for each group of control technology was identified. Control technologies that lie on this "least-cost envelope" have the lowest cost for implementation per quantity of pollutant removed. Any technologies resting above this curve represent comparably inferior technologies which have lower emission control for a greater cost. Only controls lying on the least-cost envelope should be selected for emissions reduction, barring any additional factors or considerations; however, a control technology lying on the least-cost envelope does not necessarily mean that the control technology is cost effective.

Considered in order of most effective control of SO_2 emissions, WFGD-Caustic, WFGD-Limestone, CDS, and SDA all demonstrate cost-effectiveness values which exceed values shown as not cost-effective in previous BACT studies The cost-effectiveness of WFGD-Caustic is $12,451 per ton of SO_2 removed. The cost-effectiveness of WFGD-Limestone is $12,668 per ton of SO_2 removed. The cost-effectiveness of CDS is $18,160 per ton of SO_2 removed. The cost-effectiveness of SDA is $15,533 per ton of SO_2 removed. Only DSI is anticipated to be cost-effective at $4,963 per ton of SO_2 removed. The incremental cost effectiveness is an indicator for the additional cost to increase the removal of pollutant. The incremental cost increase from DSI to caustic WFGD is $55,744 per additional ton of SO_2.

[redacted]

5.2.2 Actual Emissions vs PTE Emissions

Table 5-8 and Figure 5-1 describe the impact and cost effectiveness of each technology on a PTE basis as recommended by the EPA CCM. However, it is useful to consider the actual emissions expected from the CHPP given historical flowrates and fuel analysis. Emission reductions based on actual emissions would be much lower compared to PTE, due to lower coal consumption and lower sulfur content compared to those parameters in the PTE calculation. The PTE basis is based on a coal consumption limit [redacted] per rolling 12-month period, a base unit heat input of 230 MMBtu/hr and a coal sulfur content of 0.25 weight percent as stated in DU's Air Quality Control Minor Permit[17]. Regarding the SO_2 BACT requirements [redacted] the permit states the following:

> "The Permittee shall limit the sulfur content of coal received at the stationary source to no greater than 0.25% sulfur by weight."

This limit is a PM2.5 Serious SIP limit based on the lowest sulfur coal content that [redacted] could provide to the coal-fired plant in Fairbanks. Because the sulfur content varies with the shipment, the actual sulfur content can be much lower than the SIP limit. The average sulfur content from all coal deliveries to the CHPP in 2020 was 0.14 percent by weight, and never surpassed 0.17 percent[18]. Likewise, the maximum heat input observed from each boiler is far below the PTE rating, with combustion data suggesting a maximum unit heat input[19] of [redacted] MMBtu/hr.

Table 5-9 demonstrates the impact and cost effectiveness of each SO_2 control technology based on actual 2020 emissions. The difference in results between these two bases are significant. Given the reduced sulfur content in the fuel and the lower heat input, the expected SO_2 removal is nearly halved for all technologies, with the associated cost effectiveness nearly double compared to the PTE basis. In particular, the expected actual SO_2 emissions removed for the caustic-WFGD technology will be only [redacted] tpy compared to [redacted] tpy for the PTE basis. The associated final cost effectiveness of the caustic-WFGD is therefore increased from $12,451 per ton for the PTE basis to $24,688 per ton if actual emissions are considered. Likewise, under the actual emissions basis, the lowest cost option of DSI is increased to $11,049 per ton compared to $4,963 per ton if PTE emissions are utilized. While the PTE basis is the standard for BACT analysis, the actual emissions and associated effect on impact and cost effectiveness should be considered.

[17] AQ1121MSS04 Section 3, #5 – Issued June 30, 2021
[18] DU Monthly Historian Data – 2020
[19] Based on heat balance calculations from B&V using 2020 coal analysis and [redacted] lb/hr of generated steam

Table 5-9 Impact and Cost Analysis – Estimated Actual Emissions (2021$)

ALL FEASIBLE TECHNOLOGIES	UNIT	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS + PJFF	DSI
Emission Performance Level	lb/MMBtu	0.04	0.04	0.07	0.07	0.12
[redacted]						
SO_2 Emission Removed	tons/yr	690.5	690.5	628.2	628.2	524.3
Capital Costs	1,000$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Annualized Cost	1,000$	17,046	17,343	20,090	23,488	5,793
Cost Effectiveness	$/ton SO_2	24,688	25,118	31,983	37,392	11,049

5.2.3 Vendor-Proposed Emission Rates

In the original RFQ, Black & Veatch provided vendors with target SO_2 emissions rates for each control technology. These rates were based on the average emission rates of the top 20 and 50 percent coal-fired power plants as provided in the EPA's cost control manual. However, to better identify the upper limit of each SO_2 control technology and to rank them for BACT determination, vendors were contacted with a follow-up request for the lowest emission rates for each technology over a three-hour time averaging period. This averaging period ensures that the effects of start-up, shut-down, and upset periods are considered in the emission rate.

Andritz, B&W Environmental and Tri-Mer were included in this request. Black and Veatch received full responses from all three vendors and a summary of their expected emissions and cost reductions are shown below.

Table 5-10 Vendor Provided Emission Rates (3-hour Time Averaging)

3-HR EMISSION RATES (LB SO_2/MMBTU)	WFGD – CAUSTIC	WFGD – LIMESTONE	SDA	CDS
Andritz	0.02	-	0.06	0.02
B&W Environmental	-	0.04*	0.04*	0.04*
Tri-Mer	0.04	-	-	0.03
Average Emission Rate	0.03	0.04	0.05	0.03

*B&W Environmental offers that technologies may be able to achieve lower rates but does not feel comfortable guaranteeing lower emission limits for a 3-hour rolling average due to load swings. Further reliability would increase design costs.

The vendors' responses include lower values than those used in this report, down to 0.02 lb/MMBtu for a CDS and caustic WFGD. To validate these values, emissions data from 2016 to 2021 was queried from the EPA's AMPD on a monthly basis for a sodium-based FGD, a dry lime FGD (the AMPD tool does not allow the query to be filtered by CDS or SDA, only a dry lime FGD), and a limestone WFGD. The lowest 20 percent of all emission rates were collected and averaged for each technology. Datapoints below 0.02 lb/MMBtu were excluded from the collection range as they appeared unpractical and erroneous in nature and are irrelevant in comparison with vendor emission rates which do not go below 0.02 lb/MMBtu.

With these considerations, the lowest 20-percent average emission rates were determined as 0.07 lb/MMBtu for the sodium-based FGD, 0.05 lb/MMBtu for the dry lime FGD, and 0.04 lb/MMBtu for the limestone WFGD. These rates are all higher than the minimum emission rates provided by the vendors. While it is true that new units can be designed to provide more removal than the units in the AMPD, these values reflect the lowest 20 percent of emitters in an attempt to consider the units that operate the best and with the highest level of design. The difference between the AMPD values and the vendors' responses highlight how there can be a significant difference between what vendors feel can be achieved during conceptual design and the emissions achieved after detailed design, construction, and commissioning. The values that the vendors provided are values that they have observed in the past, but there are differences between all units that can affect a system's design and performance. At this time, there is low confidence that the vendors' emission rates will be achieved at CHPP. It is worth noting that the values from the AMPD are similar to the EPA CCM state average for the top 20 percent emission rates (0.07 lb/MMBtu for a sodium-based FGD, 0.04/0.07 for an SDA/CDS, and 0.02 for a limestone WFGD).

Table 5-11 Minimum Emission Rate Comparison for SO_2 Control Technologies

CONTROL TECHNOLOGY	AMPD AVERAGE TOP 20 PERCENT[1]	EPA CCM AVERAGE TOP 20 PERCENT[2]	VENDOR-PROVIDED MINIMUM EMISSION RATES
Caustic-WFGD	0.07	0.07	0.02
Limestone-WFGD	0.04	0.02	0.04
SDA	0.05	0.04	0.04
CDS	0.05	0.07	0.02

[1] Average of lowest 20-percent emission rates between 2016 and 2021 | https://ampd.epa.gov/ampd
[2] Section 5 - Chapter 1: Wet and Dry Scrubbers for Acid Gas Control Table 1.3 | epa.gov

Table 5-12 demonstrates the effects of the increased SO2 removal on impact and cost effectiveness. Even if such emission rates were achievable and able to be guaranteed by the vendor, the use of the vendor-provided emissions rates does not alter the result of the overall cost-effectiveness analysis. The effect on the CDS design is significant, with a decrease from [redacted] per ton to [redacted] per ton, but it is still far from being considered a cost-effective technology and remains an inferior control to caustic-WFGD.

Table 5-12 Impact and Cost Analysis – Vendor Emissions (All Costs are in 2021$)

ALL FEASIBLE TECHNOLOGIES	UNIT	WFGD - CAUSTIC	WFGD - LIMESTONE	SDA	CDS + PJFF	DSI
Emission Performance Level	lb/MMBtu	0.02	0.04	0.04	0.02	0.12
[redacted]						
SO_2 Emission Removed	tons/yr	1,419.5	1,369.1	1,369.1	1,419.5	1,167.2
Capital Costs	1,000$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Annualized Cost	1,000$	17,046	17,343	20,090	23,643	5,793
Cost Effectiveness	$/ton SO_2	12,008	12,668	14,674	16,655	4,963
Incremental Cost Effectiveness	$/ton SO_2	44,595	57,215*	70,823*	70,739*	--
*Note: Only WFGD-Caustic and DSI are on the least-cost envelope; incremental analysis is shown for reference only						

The data provided in Table 5-12 shows that the quantity of SO_2 removed is largely unchanged compared to the original basis used in Table 5-8. In this scenario, the CDS technology and caustic-WFGD would provide the most effective control of SO_2, while the limestone-WFGD and SDA would provide the second-most effective control. Each control technology, except for DSI, is demonstrated as not- cost-effective. Because the result of the cost-effectiveness analysis is unchanged, and because of the low confidence in the ability of these technologies to consistently meet the vendor emission rates in practice, this BACT analysis retains the base case emission rates from the EPA CCM. The cost effectiveness and impact as descripted in Section 5.2.1 best represent the achievable emission rates in practice.

6.0 Evaluate Most Effective Controls (Step 4)

In the following subsections, the technically feasible emissions control alternatives are evaluated with respect to their energy, environmental, and economic impacts [redacted] The two (2) described alternate wet FGD technologies will have similar energy, environmental, and economic evaluations. In the interest of a complete technology analysis, an SDA, CDS and DSI will be evaluated further along with a wet FGD.

6.1 ENERGY EVALUATION OF ALTERNATIVES

The DSI control technology has the lowest energy demand of the SO_2 control alternatives (less than 50-percent of auxiliary power compared to the others). This is because the sorbent is only being injected in the duct and there is no added ductwork or equipment to pass through which would add pressure drop (higher aux. power from ID/FD fans). The caustic-WFGD and the spray dryer absorber (SDA) have lower energy demands than a limestone-WFGD and CDS, because there is not as much equipment for each. The caustic-WFGD does not have the reagent preparation system, dewatering system, and oxidation air blowers required for a limestone-FGD system. The SDA system does not have the byproduct recirculation system (fluidization slides, rotary feeders, etc.) and the added pressure drop of the recirculation system compared to a CDS. All of the SO_2 control alternatives utilize a PJFF which have approximately the same pressure drop across it except for the CDS. The CDS and PJFF has the recirculation system which benefits reagent consumption but adds pressure drop that the draft system has to provide. The total auxiliary power of the CDS is similar to the limestone-WFGD. In the limestone-WFGD, the majority of the energy consumption is attributed to reagent preparation for grinding the limestone and the high pumping power requirements dictated by the high liquid-to-gas (L/G) ratio required for these processes. The ability to increase the L/G ratio at the expense of higher energy use allows this system the capability of achieving the high emissions removal rates required for this facility.

6.2 ENVIRONMENTAL EVALUATION OF ALTERNATIVES

There are potential environmental effects associated with adding any SO_2 control technology, and they are further examined below.

Visible Stack Gas Plume

A WFGD system will result in a visible moisture plume almost year-round. Because the SDA, CDS, and DSI systems do not saturate the flue gas with water, there is no visible plume from the stack under most weather conditions. The calculated moisture that would be added to the flue gas exiting the stack with a WFGD system for [redacted] boilers in operation at full load is approximately 20 gallons per minute or 1,200 gallons per hour. The plume coming out a WFGD system is a saturated steam plume.

Ice Fog Formation

Doyon Utilities has identified an increased risk for the generation of ice fog as a serious collateral environmental impact associated with the increased moisture in the exhaust gas.

Ice fog formation is an event that can occur during stable atmospheric conditions at temperatures of -30°C or lower and low wind speeds in the lowest 500 meters of the atmosphere. Temperatures below -40°C can lead to heavier ice fog events. Climatological studies performed near Fort Wainwright show the area is prone to periodic ice fog when cold air from Siberia moves into the region, accompanied by a strong anticyclone. Based on a study by Shulski and Wendler in 2007, the average temperature in Fairbanks is -21°C in January[20]. The 2007 study also indicated that on average there are 10-days in January where ambient temperatures are at or below -40°C. A 2016-2019 study indicated 11 total ice fog events occurred in Fairbanks where temperatures were at or below -35°C with nearly calm winds during January of each year. The longest event lasted 81-hours with the average event lasting 28.5-hours.

Ice fog is made up of solid droxtals (ice particles) with at least 95-percent of the ice particles ranging between 7 to 50 μm in diameter[21]. The small size allows the particles to stay suspended in the lower atmosphere for extended periods of time. Ice fog comes from supersaturated atmospheric conditions that are caused by water vapor primarily from human sources such as power plants, cooling ponds, and exhaust from emission-controlled engines. A study by Porteous and Wallis in 1970 studied the contribution of power plants in Alaska to ice fog, and the study concluded that 59 percent of the water vapor at military bases was from the power plants' flue gas, and another 32 percent was from the plants' old cooling pond.

Based on a study by Weatherly, Shaw, Peckham, and Douglas it was found that "…given the best forecasts/simulations of weather conditions, the formation of ice fog remains a poorly understood and challenging to predict phenomenon." Installing controls associated with an increased exhaust moisture increases risk for ice fog formation, which could have detrimental impacts to Fort Wainwright operations and mission, as well as homeland security. Weatherly et al documented that water vapor from the current power plant has a drift radius of 2 kilometers. Increased ice fog from proposed BACT controls could result in a safety incident /failure of such magnitude the US Army will cease operations.

Ice fog can also be associated with frost formation which can accumulate on powerlines, aircrafts, roads, and other infrastructure. Although accumulations of ice fog and any associated frost formation due to ice fog will be relatively light on exposed surfaces, ice fog can and does lead to slick and even frost covered surfaces in addition to visibility reductions. This is of particular concern due to the CHPP's location relative to major roads and airways.

The CHPP is located within one mile of the Richardson Highway, a main thoroughfare in the Fairbanks area. The Richardson Highway connects Fairbanks and Valdez, Alaska. The highway is one of only two arteries providing access to the Fairbanks area from outside of Alaska via roadways

[20] NOAA Climate Normals 1981-2010 for Fairbanks, Alaska.

[21] Ice Fog Monitoring Near Fairbanks, Alaska, March 2021, US Army Corps of Engineers, Engineer Research and Development Center.

and the Alaska Marine Highway System. The Richardson Highway provides connections to points east of Fairbanks, including access to the ALCAN Highway (also known as the Alaska Highway or the Alaska-Canadian Highway). The northern terminus of the ALCAN Highway is in Delta Junction, Alaska. As shown in Figure 6-1, the portion of the Richardson Highway between Delta Junction and Fairbanks (corridor highlighted) offers the only road access to Fairbanks from Canada and the lower 48 states.

Image Source: Bell's Travel Guides | https://www.bellsalaska.com/city-and-highway-maps/

Figure 6-1 Richardson Highway Corridor

The Richardson Highway is a public road used by industry, commercial interests, the military, and private citizens. In addition to Fort Wainwright in Fairbanks, the Army has several training areas and other facilities which are accessed from the Richardson Highway including Fort Greely in Delta Junction. Eielson Air Force Base is located on the Richardson Highway approximately eight miles south of North Pole, Alaska. The highway provides commuters from North Pole, Eielson AFB, and many other communities to the south and east of Fairbanks with the only access to Fairbanks. The highway is used by everyone from the eastern portion of Alaska for driving to Fairbanks to access healthcare, purchase supplies, conduct business, or connect to air travel at Fairbanks International Airport (FAI/PAFA). The critical nature of the Richardson Highway at its Fairbanks terminus was addressed in the 2015 Planning and Environmental Linkages (PEL) Study Report[22] for the Richardson Highway/Steese Expressway Corridor (DOT&PF Project No. 60799). The PEL provided the following statements:

> *"Due to its central location, the Fairbanks North Star Borough (FNSB) is the transportation, trade, and service center for the vast interior and northern regions of Alaska. Within the borough, the Richardson-Steese corridor serves as a key transportation system in eastern*

[22] 2015 PEL Study Report | https://dot.alaska.gov/nreg/richardson-steese/files/pel-study-public-review-draft.pdf

Fairbanks, providing connectivity between Fairbanks, North Pole, Fort Wainwright, Eielson Air Force Base (AFB), and road-connected areas north of Fairbanks, including the North Slope oil fields. The corridor is part of the National Highway System (NHS) and is designated Alaska Route 2. …this corridor is a critical part of the statewide freight network and provides a link with the George Parks, Elliott, Dalton, and Alaska Highways to connect Fairbanks with Valdez, Prudhoe Bay, Anchorage, Canada, and the continental United States."

"The Richardson Highway and the Steese Expressway are identified as critical freight infrastructure in the Fairbanks Metropolitan Area Transportation System (FMATS) Metropolitan Transportation Plan (MTP). Fairbanks is a key transportation hub in Interior Alaska and the "doorway" to the Dalton Highway and the North Slope oil fields."

"The Richardson-Steese corridor is also part of the Strategic Highway Network (STRAHNET). STRAHNET is a system of public highways that provide for essential movement of military personnel and equipment to and from military bases during both peacetime and war. This corridor provides a strategic surface transportation connection for transporting military personnel and equipment into and out of Fort Wainwright including movement of convoys to training exercise areas south and east of Fairbanks (United States [U.S.] Army Transportation Engineering Agency, 2015; FHWA, 2015a and 2015b; ASCG, 2006)."

As shown in Figure 6-2, the Richardson Highway terminus in Fairbanks abuts the Fort Wainwright garrison. The CHPP is located approximately 0.60 miles from the closest segment of the Richardson Highway. Winds in the Fort Wainwright/Fairbanks area are predominantly out of the northeast, as shown in the wind rose provided in Figure 6-3. As a result, any operational changes at the CHPP which might result in increased ice fog formation, frequency, or severity would likely have a negative impact on the Richardson Highway northern terminus corridor.

[redacted]

[redacted]

Figure 6-2 Richardson Highway Fairbanks Terminus and Fort Wainwright CHPP

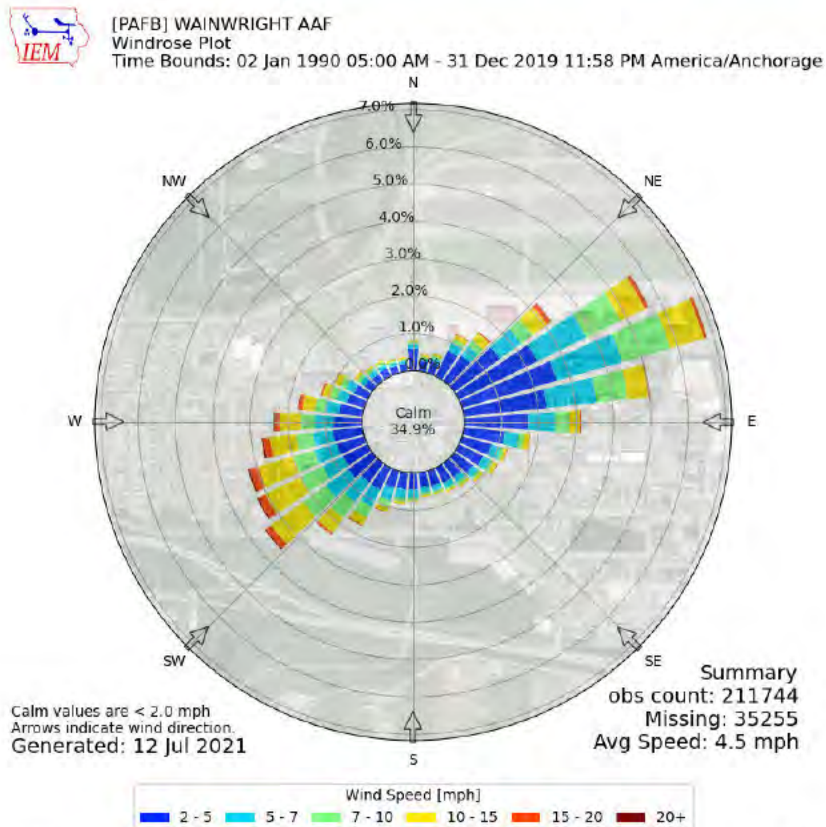

Image Source : Iowa State Environmental Mesonet | https://mesonet.agron.iastate.edu/sites/locate.php?network=AK_ASOS

Figure 6-3 Wind Rose at Fort Wainwright

A study by the US Army Corps of Engineers[23] was conducted to investigate ways to suppress ice fog from the CHPP's cooling pond. The study calculated the stopping sight distance (SSD) to be 700 ft for vehicles traveling 55 mph on icy roads on the Richardson highway. Based on three years of winter data, ice fog from the cooling pond reduced visibility to less than 700 ft for 25 days, or effectively 8 days each year. To improve road safety conditions, in 2007, the cooling pond was decommissioned and air-cooled condensers were installed.

In addition to problems with the Richardson Highway, ice fog has also led to visibility concerns for airplanes in the region. Figure 6-3 illustrates that the other predominant wind direction is from the southwest. Ladd Army Airfield is located less than 0.5 miles northeast of the CHPP. Notably, a Canadian military plane carrying 18 people crashed in 1989 due to poor visibility from ice fog[24].

Ice fog does present potential negative impacts from icing/frosting and visibility reduction at the Fort Wainwright Facility. Safety concerns at the Fort Wainwright Facility as well as potential safety impacts to the public need to be considered. This is particularly important considering that

[23] Brunner, Walker. Suppression of Ice Fog from the Fort Wainwright, Alaska, Cooling Pond. Oct 1982. | Appendix F
[24] Deseret News. 8 Killed and 10 Injured in Crash of Canadian Military Plane in Alaska. Jan 30, 1989. | Appendix F

Fort Wainwright is the US Army's northern-most military installation and is strategically significant to the nation's security. Home of a rapid-deployment Stryker Brigade Combat Team and multi-battalion Aviation Task Force, Fort Wainwright is a critical part of the Army's Arctic Strategy as a force-projection platform capable of training arctic combat forces and deploying them worldwide. Ladd Army Airfield, located just over a half mile from the CHPP, is central to the installation's mission to train and deploy combat forces. With an 8,575-ft runway, Ladd Army Airfield serves as an airport of Embarkation and Debarkation (APOD/APOE) for the Air Force's largest strategic airlift aircraft.

The addition of a wet FGD system would increase the stack exhaust moisture values by about 52 percent, and if an SDA/CDS system is used, stack moisture values would increase by about 20 percent[25]. These options would add significant moisture to the stack exhaust and lead to increased ice fog during ice fog events. The increase in ice fog would also lead to more icing/frost accumulations in and around the Fort Wainwright Facility, such as the Richardson Highway and nearby military bases.

Options to reduce the potential for ice fog are limited. Heating of the plume from the plant exhaust stacks would likely reduce plume interaction with additional plumes generated through other plant operations. However, the characteristic strong low-level inversion associated with ice fog events will likely keep the stack exhaust plume from rising substantially further than it would without the additional heating of the plume. Therefore, the heating of the stack exhaust plume may not be a useful form of ice fog mitigation, especially since the stack ice fog plume (ice particles) will settle back down to the ground both at the Fort Wainwright Facility as well offsite away from the facility due to the strong low-level inversion.

Another option would be to remove the moisture from the stack gas using cooling and compression methods. This study was not able to identify a system of the size and duty required for the CHPP's purposes, so a cost could not be included. However, one should expect the procurement and installation of such a device to increase the project costs by multiple millions of dollars, and further investigation would be required to assess the auxiliary impacts it would have (e.g., power demands, pressure loss impacts, etc.).

The existing equipment at the CHPP does not have a saturated steam plume and Fort Wainwright and its surrounding areas currently operate without having to remediate ice fog contributions from the CHPP. However, if a new AQC system were installed that significantly increased the frequency and strength of ice fog events, Fort Wainwright and the surrounding areas could mandate that the AQC system cease operations, similar to how the cooling pond was decommissioned. In addition, ADEC can require a facility to obtain a permit and reduce water emissions to limit ice fog impacts in an area of potential ice fog, as provided in Title 18 Alaska Administrative Code Chapter 50 (18 AAC 50.080). With these considerations, the effect of increased stack moisture on of ice fog formation represents an excessive risk to Fort Wainwright's mission and to USA homeland security.

[25] Based on desulfurization equipment mass balances

Please see Appendix F for more information regarding the ice fog.

Water Consumption

The caustic-WFGD and limestone-WFGD systems utilize a significant amount of water to reduce the flue gas temperature to saturation, where the scrubbing of SO_2 occurs. For comparison purposes, water consumption rates for SDA and CDS systems are approximately 85 to 90 percent less than that required for the WFGD systems. The DSI system water consumption rate is approximately 87 to 92 percent less than that required for the WFGD systems. The caustic-WFGD consumption rate of water is approximately 11,900 gallons per hour (assuming [redacted] boilers are at full load) which is the largest user of water for control technologies being evaluated. The additional required process water is another issue to consider since Fort Wainwright is a Superfund site and there may be impacts to surrounding contaminated ground water. The current process water required for the caustic-WFGD is approximately 286,000 gallons per day. The current water demand at Fort Wainwright's water plant is approximately 1,000,000 gallons per day. [redacted]

The potable water system at FWA consists of a raw water source, treatment, storage, and distribution facilities. Groundwater wells supply the post with raw water containing high levels of iron and manganese. The water treatment plant (Building 3565) adds chlorine and potassium permanganate to oxidize metals in the water and passes it through a filter containing anthracite, manganese green sand, and gravel to complete oxidation and remove the reacted material. Chlorine, fluoride, and soda ash are added after filtering and the treated water is then stored in the clear wells for use in FWA's potable and fire suppression systems.

The nature of the mission at FWA causes the facility to generate or to be generated a variety of materials, wastes, and substances whose disposal is now highly regulated. Previously acceptable practices regarding storage, use, handling, and disposal of chemicals caused those chemicals to enter the natural environment, creating contamination or environmental impairment. Former operations at the post which may have caused contamination include fire-fighting training, vehicle maintenance, chemical disposal, ordinance disposal, dry cleaning, and live fire training.

In response to environmental regulations, numerous potential sources or sites of contamination were identified at FWA. The extent of contamination and potential contamination caused FWA to be proposed for listing on the National Priorities List (NPL) in July 1989 and finalized on the NPL in August 1990. The NPL identifies those locations which are deemed to be heavily impacted by hazardous substances and should therefore receive priority consideration from the US EPA and partnering state agency, Alaska Department of Environmental Conservation (ADEC). A Federal Facility Agreement (FFA) between the US EPA, the Army, and ADEC was signed in March 1992. Given the NPL status of the FWA site and potential pre-existing groundwater contamination, extra consideration should be given against SO_2 control technologies which substantially increase water demands on the site. Of all control technologies considered, DSI is the only option which does not [redacted] strain the capacity of the overall system and has the least water consumption.

Byproduct Disposal

The byproduct disposal ranges from 1 ton/hr for the DSI system, 1.1 ton/hr for the SDA and CDS, to 1.24 ton/hr for the limestone-WFGD. The solid waste generated from the limestone-WFGD, SDA, CDS, and DSI are an issue because the current landfill is unlined and is near capacity. The caustic-WFGD does not have a byproduct disposal stream because all waste products are water soluble. This becomes a larger wastewater issue for CHPP because of the additional wastewater load on the local public treatment facility. The calculated wastewater generated from the caustic-WFGDs is approximately 3,200 gallons per hour [redacted]

While not performed at this time, conceptual engineering efforts may identify the need for a new landfill due to limited space at existing landfills in the area or no landfills in the area being willing to accept the byproducts. A new landfill would add significant additional costs to the project. In addition to the cost of the land and building the landfill, the landfill will need proper lining to contain leachate from the byproducts, and post-closure costs to account for the leachate that is collected from the landfill. Zoning requirements in the area will dictate the location and dimensions of the landfill and will have a large effect on the cost. Based on typical requirements it is reasonable to expect that a new landfill will cost upwards of a million dollars and potentially significantly more. Furthermore, this facility would have considerable operation and maintenance costs in addition to capital costs.

Wastewater Treatment

The Control Authority for the City of Fairbanks/ Golden Heart Utility (GHU) wastewater industrial pretreatment program issued an Industrial Wastewater Discharge Permit to the US Army. The FWA Wastewater Collection System receives domestic and industrial discharges from facilities located on FWA including DU's CHPP. The DU CHPP is considered an industrial process within the permitted SIU. Therefore, discharges from the DU CHPP are required to be characterized before entering the FWA Wastewater Collection System. The purpose for monitoring the CHPP industrial discharge is to document the characteristics of that wastewater stream as a component of the overall FWA wastewater discharge to ensure that it meets the GHU discharge criteria and general compliance with the Army's industrial water discharge permit. [redacted]

The additional wastewater from caustic WFGDs at the CHPP is estimated to be about 76,000 gallons per day (depending on the season). This represents a [redacted] increase in the current average daily flow for the current wastewater collection system. In addition to the increased flow, the permit with GHU restricts the sulfides in the water to 1.0 mg/L. Caustic scrubbers create sulfides as a primary reaction product, resulting in a sulfide-rich wastewater stream is expected to be in excess of 5,900 mg/L. This large volume of high-sulfide wastewater must be treated beyond simple dilution in order to meet the GHU permit. A similar situation exists with the limestone WFGD, where the permitted TSS limit is 500 mg/L, but the waste stream has a TSS concentration near 43,000 mg/L.

Table 6-1 Caustic-WFGD Wastewater Composition

PARAMETER	UNITS	VALUE
Combined wastewater flowrate	gal/day	76,154
Sulfides removed in wastewater stream	ton/day	1.88
Undiluted wastewater sulfide concentration	mg/L	5,906
Permit sulfide limit	mg/L	1.0

Table 6-2 Limestone-WFGD Wastewater Composition

PARAMETER	UNITS	VALUE
Combined wastewater flowrate	gal/day	180
TSS removed in wastewater stream	lb/day	64.62
Undiluted wastewater TSS concentration	mg/L	43,021
Permit TSS limit	mg/L	500

Doyon Utilities investigated whether the 1.0 mg/L sulfide permit limit was negotiable with GHU. GHU [redacted] denied this request to increase the permit limit, stating that no more than 1.0 mg/L sulfides can be discharged to protect the downstream wastewater system infrastructure. The cost impact of increased sulfide treatment for the wastewater stream was not evaluated as part of this project nor was a new wastewater treatment facility included in the cost estimate. However, based on previous projects, the cost would be expected to be near 10 million dollars for purchasing the equipment, and at least twice the equipment cost can be expected to be required for installation and commission. This additional cost consideration - potentially $30 million dollars just for capital- was not factored into the study's BACT analysis.

The byproduct and wastewater items for WFGD options would have a significant impact on the cost effectiveness calculated as part of this analysis, but neither item was included in this study, potentially resulting in a much lower $/ton removed cost than what it would actually cost. While DSI also generates wastewater streams during cleaning, the added load on the sewer system is at most 28 percent of that for a caustic-WFGD system with no additional treatment expected to meet permit sulfide limits. Of the dominant controls, DSI is the only option that does not substantially increase loading on existing wastewater treatment systems.

6.3 ECONOMIC EVALUATION OF ALTERNATIVES

The cost-effectiveness of each technically feasible emission control option is presented in Section 5.2.1. The cost-effectiveness of DSI is $4,963 per ton of SO_2 removed. The cost-effectiveness of WFGD-Caustic is $12,451 per ton of SO_2 removed. The cost-effectiveness of WFGD-Limestone is $12,668 per ton of SO_2 removed. The cost-effectiveness of CDS is $18,160 per ton of SO_2 removed. The cost-effectiveness of SDA is $15,533 per ton of SO_2 removed. Based on Black & Veatch's past experience, in order of most effective control of SO_2 emissions, WFGD-Caustic, WFGD-Limestone, CDS, and SDA would all be considered as not cost-effective and deemed not economically feasible. After considering the base costs of all five control technologies and the likely economic impact of mitigating environmental effects of implementation, the DSI system is anticipated to be the only cost-effective technology and therefore the only economically feasible control technology. Although the DSI system has a lower ceiling for achievable SO_2 removal rates compared to the other SO_2 control technologies, it is the only option which achieves significant removal within acceptable cost and no risk of collateral environmental impact.

To comply with the Fairbanks PM2.5 Serious SIP, SO_2 control measures with a cost effectiveness of approximately $14,000 per ton of SO_2 removed were approved by the Alaska Department of Environmental Conservation (ADEC) and EPA at Golden Valley Electric Association's (GVEA) North Pole Power Plant (NPPP). The control measure approved was transitioning the two existing fuel-oil fired simple cycle combustion turbines (SCCTs) to burning ultra-low sulfur diesel (ULSD). Per the unique circumstances surrounding GVEA's limited emission control options and significant SO_2 reductions that will be realized with the conversion, it has been demonstrated that although this relatively high cost-effectiveness was deemed appropriate for the NPPP, it does not indicate this cost-effective magnitude should be considered an appropriate threshold for all other projects, including the SO_2 controls to be installed on the boilers at DU's FWA.

A cost effectiveness of approximately $14,000/ton removed was warranted at GVEA's NPPP due to the significant SO_2 reductions that would be made and the lack of emission control options. As this arrangement allowed GVEA to burn ULSD during the winter months, the financial burden was reduced, justifying the higher cost effectiveness to burn ULSD for half of the year. The main difference of the SO_2 control analysis for DU's FWA is that this project has multiple, effective control technology options to consider. Potential SO_2 emissions will be significantly reduced through installation of the DSI system, reducing SO_2 emissions by 1,167 tpy. The additional reduction of approximately 200 tpy that could be realized through the installation of the WGFD systems does not justify the significant difference in cost effectiveness of these technologies ($5,793/ton removed vs $12,451 to $12,668/ton removed).

There are three main points that highlight why EPA/ADEC's acceptance of a control measure with a relatively high cost-effectiveness at the NPPP should not be interpreted as justification for a control measure with a similar cost effectiveness at DU's FWA facility. These three points are summarized below.

1. GVEA had no other feasible SO_2 control options.

Per pages 3,795 and 3,796 of Part 4 of Appendix III.D.7.07, ADEC identified four technologies as available to control SO_2 emissions from the fuel oil-fired SCCTs located at the NPPP. These four options included the firing of ULSD, the use of low sulfur fuel, limited operation, and good combustion practices.

Control technologies already in practice at the facility are considered to have 0-percent control efficiencies for the SIP BACT. Limited operation and good combustion practices had 0-percent control for this analysis because the facility has already incorporated operational restrictions and good air pollution combustion practice requirements for the SCCTs in their existing Air Quality Operating Permit, Permit No. AQ0110TVP04 (including Conditions 17, 18 and 51).

The NPPP was also required to perform a BACT analysis for PM2.5 emission control for the SCCTs. Although low sulfur diesel was identified as a potential technology for SO_2 control, ADEC determined this fuel was not a technically feasible control technology for PM2.5 control (Appendix III.D.7.7-3,785) because PM2.5 emission rates for low sulfur fuel are not available and therefore a BACT emission rate cannot be set. Due to the exclusion of all other control technologies, switching the fuel combusted in the SCCTs to ULSD was the only feasible control option to consider. Likewise, it appears a cost analysis was only completed by GVEA for ULSD and not low sulfur fuel (as evident in Table 5-2 on page 3,833 of Part 4 of Appendix III.D.7.7).

2. The cost per ton of SO_2 removed at GVEA's NPPP was only determined cost effective because of the significant amount of SO_2 reduction to be realized.

The cost per ton of SO_2 removed was calculated to be $13,838 and $13,923 for converting the two SCCTs to ULSD. Per GVEA Comment (3) on ADEC's response to comments, dated November 13, 2019, ADEC "…considers these values to be cost effective when taking into account the actual reduction in SO_2 that will be realized by the fuel switch in the Serious nonattainment area." Based on ADEC's most recent NPPP SO_2 economic analysis available for review (dated November 13, 2019), by switching to ULSD the facility will reduce potential SO_2 emissions (based on full time operation) from the two combustion turbines from 2,842.5 tons per year (tpy) to 8.5 tpy. Reducing potential SO_2 emissions by over 2,800 tons in a serious nonattainment area represents significant progress towards the transition to attainment. These noteworthy reductions likely attributed to the agency considering a higher cost effectiveness to achieve significant results.

Understanding the facility has operational restrictions in place, further review was performed to decipher a more reasonable estimate of actual SO_2 emission reductions that can be expected with the fuel conversion. As listed in Tables B-3 and B-5 of NPPP's application to revise their Title I Air Quality Permit, dated June 9, 2020, potential emissions (incorporating operational restrictions and the SIP requirement to combust ULSD during the winter months), from the two combustion turbines will be reduced from 2,269 tpy to 1,490 tpy, a reduction of approximately 780 tpy. This reduction is likely more indicative of the reductions to be expected at the NPPP, however continues to represent a significant decrease of potential SO_2 emissions in a serious nonattainment area.

3. It was ultimately determined by ADEC/EPA that GVEA is only required to burn ULSD between October 1 – March 31, reducing their financial burden.

Per Table 7.715 of III.D.7-7, the SCCTs at the NPPP are only required to burn ULSD from October 1 – March 31 of each year. An updated cost analysis was not made available for this shortened time period; however, this determination will result in significant fuel cost savings for GVEA (a difference of $0.424 per gallon when comparing ULSD to the #2 fuel oil currently in use). Although the cost effectiveness values may not significantly change, the option to burn fuel oil with a higher sulfur content (1,000 ppmw versus 15 ppmw) for half of each year (and approximately one third of their total fuel use[26]) will result in material savings for GVEA annually, making the approximate $14,000 per ton of SO_2 removed less of a burden on the facility since it does not apply year-round.

[26] Based on NPPP's historical operating schedule as reported in 2015 – 2019 | Point Source Emission Inventory | https://dec.alaska.gov/Applications/Air/airtoolsweb/pointsourceemissioninventory

7.0 BACT Selection (Step 5)

A top-down approach was taken to evaluate the control strategies in selecting the best alternative. Table 7-1 illustrates a summary of the SO_2 control alternatives, including the emissions levels, total annualized costs, and cost effectiveness. A review of Table 7-1 demonstrates that while the application of the most stringent control technology (WFGD at 0.04 lb/MMBtu) provides the lowest emissions, it does so at a significant cost on an annualized and dollar per ton basis, beyond what is typically considered cost-effective, as discussed in Section 6.3 based on Black & Veatch's experience. The other two control technologies, SDA and CDS, provide low emissions at 0.07 lb/MMBtu, but are inferior controls to the two WFGD technologies and are also not considered to be cost-effective. Per the analysis of Section 6.0 (Step 4), the DSI technology had the lowest energy demand, had the least environmental impact, and is considered to be the only cost-effective solution compared to Wet FGD-caustic, Wet FGD-limestone, CDS-PJFF, and SDA.

Therefore, the recommended BACT for SO_2 at the CHPP is DSI.

Table 7-1 BACT Analysis Summary and Results (All Costs are in 2021$)

CONTROL ALTERNATIVE	EMISSION LEVEL (LB/MMBTU)	ANNUALIZED COST (1,000$)	COST EFFECTIVENESS ($/TON)
Wet FGD – Caustic	0.04	$17,046	$12,451
Wet FGD – Limestone	0.04	$17,343	$12,668
SDA	0.07	$20,090	$15,533
CDS-PJFF	0.07	$23,488	$18,160
Presumptive BACT 0.12 lb/MMBtu			
DSI	0.12	$5,793	$4,963

Appendix A. Design Basis

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Appendix B. Summary Sheets for Cost Estimates

Direct Costs			
Purchased equipment costs	[redacted]	Vendor Quotes (Andritz and Tri-Mer)	
Absorber towers	---	Included with vendor quote	
Reagent feed system: receiving, storage	---	Included with vendor quote	
Make up water pump, dampers	---	Included with vendor quote	
Chemical feed pump (NaOH) and recycle pump	---	Included with vendor quote	
Mist eliminators and exhaust blowers	---	Included with vendor quote	
Flue gas handling: interconnecting ductwork	---	Included with vendor quote	
ID fans, Motors, VFDs	---	Vendor Quotes (Andritz)	
Subtotal capital cost (CC)	[redacted]		
Taxes	Excluded		
Freight	Incl. with Equip. Costs		
Total purchased equipment cost (PEC)	[redacted]		
Direct installation costs			
Foundation & supports	[redacted]	Engineering Estimator	
Structural steel	[redacted]	Engineering Estimator	
Handling & erection	[redacted]	Engineering Estimator	
Electrical	[redacted]	Engineering Estimator	
Piping		Engineering Estimator	
Insulation		Engineering Estimator	
Painting		Engineering Estimator	
Instrumentation and controls		Engineering Estimator	
Total direct installation costs (DIC)			
Site preparation	[redacted]	Engineering Estimator	
Buildings		Engineering Estimator	
New wet common stack		Engineering Estimator	
Total direct costs (DC) = (PEC) + (DIC)			
Indirect Costs			
Engineering	[redacted]	Engineering Estimator	
Construction and field expenses		Engineering Estimator	
Owner's cost		Engineering Estimator	
Start-up		Engineering Estimator	
Performance test		Engineering Estimator	
Contingencies		Engineering Estimator	
Total indirect costs (IC)			
Allowance for Funds Used During Construction (AFDC)	[redacted]	[(DC)+(IC)] X [redacted]	1 year(s)
Total Capital Investment (TCI) = (DC) + (IC)	[redacted]		

Figure B-1 Caustic WFGD Capital Costs Calculations

ANNUAL COST				
Direct Annual Costs		Cap. Factor	39.0%	Cumulative coal consumption limit PTE basis
Fixed annual costs				
Operating and support labor	[redacted]	6 FTE and	[redacted]	Estimated manpower level
Maintenance labor		1.1 x	Operating Labor	Per EPA Cost Manual
Maintenance materials		1 x	Maintenance Labor	Per EPA Cost Manual
Total fixed annual costs				
Variable annual costs				
Reagent: 50% solution of NaOH	[redacted]	0.99 tph and	[redacted]	Vendor budgetary quote
Byproduct disposal (Wastewater)		3,173 gph and		Vendor waste rate and DU cost
Auxiliary and ID fan power		1,350 kW and		2020 DU weighted average costs
Water		11,899 gph and		Vendor water rate and DU cost
Total variable annual costs				
Total direct annual costs (DAC)				
Indirect Annual Costs				
Administrative charges (G&A, property tax, and insur.)	[redacted]	(TCI) X	[redacted]	Cost Manual, Section 5 SO_2 Controls, 1.3.4.2
Cost for capital recovery		(TCI) X		[redacted]
Total indirect annual costs (IDAC)				
Total Annual Cost (TAC) = (DAC) + (IDAC)	[redacted]	$/ton SO_2		

Figure B-2 Caustic WFGD Annual Costs Calculations

Direct Costs			
Purchased equipment costs	[redacted]	Vendor Quotes (Andritz and Tri-Mer)	
Absorber towers (tray, spray headers, mist eliminators)	--	Included with vendor quote	
Reagent feed system: receiving, storage	--	Included with vendor quote	
Absorber recirculation pumps and recirculating piping	--	Included with vendor quote	
Oxidation air blowers and injection lances	--	Included with vendor quote	
Reagent preparation system: silo, mills, pumps, and tanks	--	Included with vendor quote	
Dewatering system: hydrocyclone, vacuum filter, pumps, etc.			
Integral stack and pressure control inlet dampers			
Flue gas handling: interconnecting ductwork	--	Included with vendor quote	
Fan modifications: six booster fans	--	Vendor Quotes (Andritz)	
Subtotal capital cost (CC)	[redacted]		
Taxes	Excluded		
Freight	Incl. with Equip. Costs		
Total purchased equipment cost (PEC)	[redacted]		
Direct installation costs			
Foundation & supports	[redacted]	Engineering Estimator	
Structural steel		Engineering Estimator	
Handling & erection		Engineering Estimator	
Electrical		Engineering Estimator	
Piping		Engineering Estimator	
Insulation		Engineering Estimator	
Painting		Engineering Estimator	
Instrumentation and controls		Engineering Estimator	
Total direct installation costs (DIC)			
Site preparation	[redacted]	Engineering Estimator	
Buildings		Engineering Estimator	
New wet common stack		Engineering Estimator	
Total direct costs (DC) = (PEC) + (DIC)			
Indirect Costs			
Engineering	[redacted]	Engineering Estimator	
Construction and field expenses		Engineering Estimator	
Owner's cost		Engineering Estimator	
Start-up		Engineering Estimator	
Performance test		Engineering Estimator	
Contingencies		Engineering Estimator	
Total indirect costs (IC)			
Allowance for Funds Used During Construction (AFDC)	[redacted]	[(DC)+(IC)] X [redacted]	1 year(s)
Total Capital Investment (TCI) = (DC) + (IC)	[redacted]		

Figure B-3 Limestone WFGD Capital Costs Calculations

ANNUAL COST				
Direct Annual Costs		Cap. Factor	39.0%	Cumulative coal consumption limit PTE basis
Fixed annual costs				
Operating and support labor	[redacted]	8 FTE and	[redacted]	Estimated manpower level
Maintenance labor		1.1 x	Operating Labor	Per EPA Cost Manual
Maintenance materials		1 x	Maintenance Labor	Per EPA Cost Manual
Total fixed annual costs				
Variable annual costs				
Reagent: Limestone (CaCO3)	[redacted]	0.65 tph and	[redacted]	Mass balance calculations
Byproduct disposal (Landfill)		1.24 tph and		Mass balance calculations
Byproduct disposal (Wastewater)		180 gph and		Mass balance calculations
Auxiliary and ID fan power		1,350 kW and		2020 DU weighted average costs
Water		120 gpm and		Mass balance calc. and DU cost
Total variable annual costs				
Total direct annual costs (DAC)	[redacted]			
Indirect Annual Costs				
Administrative charges (G&A, property tax, and insur.)	[redacted]	(TCI) X	[redacted]	Cost Manual, Section 5 SO_2 Controls, 1.3.4.2
Cost for capital recovery		(TCI) X		[redacted]
Total indirect annual costs (IDAC)				
Total Annual Cost (TAC) = (DAC) + (IDAC)	[redacted]			
		$/ton SO_2		

Figure B-4 Limestone WFGD Annual Costs Calculations

Direct Costs		
Purchased equipment costs	[redacted]	Vendor Quotes (Andritz and B&W)
Absorber vessels, including roofgas dispersers	---	Included with vendor quote
Atomizers	---	Included with vendor quote
Reagent preparation system: silo, slakers, pumps, and tanks	---	Included with vendor quote
Recycle system: silo, rotary feeders, pumps, and tanks	---	Included with vendor quote
Interconnecting ductwork and new PJFF inlet manifolds	---	Included with vendor quote
ID fans, Motors, VFDs	---	Included with vendor quote
Subtotal capital cost (CC)	[redacted]	
Taxes	Excluded	
Freight	Incl. with Equip. Costs	
Total purchased equipment cost (PEC)	[redacted]	
Direct installation costs	[redacted]	
Foundation & supports		Engineering Estimator
Structural steel		Engineering Estimator
Handling & erection		Engineering Estimator
Electrical		Engineering Estimator
Piping		Engineering Estimator
Insulation		Engineering Estimator
Painting		Engineering Estimator
Instrumentation and controls		Engineering Estimator
Total direct installation costs (DIC)		
Site preparation	[redacted]	Engineering Estimator
Buildings		Engineering Estimator
Total direct costs (DC) = (PEC) + (DIC)		
Indirect Costs		
Engineering	[redacted]	Engineering Estimator
Construction and field expenses		Engineering Estimator
Owner's cost		Engineering Estimator
Start-up		Engineering Estimator
Performance test		Engineering Estimator
Contingencies		Engineering Estimator
Total indirect costs (IC)		
Allowance for Funds Used During Construction (AFDC)	[redacted]	[(DC)+(IC)] X [redacted] 1 year(s)
SDA Capital Investment (TCI) = (DC) + (IC)	[redacted]	

Figure B-5 SDA Capital Costs Calculations

ANNUAL COST					
Direct Annual Costs		Cap. Factor	39.0 %	Cumulative coal consumption limit PTE basis	
Fixed annual costs					
Operating labor	[redacted]		6 FTE and	[redacted]	Estimated manpower level
Maintenance labor			1.1 x	Operating Labor	Per EPA Cost Manual
Maintenance materials			1 x	Maintenance Labor	Per EPA Cost Manual
Total fixed annual costs					
Variable annual costs					
Reagent: Pebble Lime (CaO)	[redacted]		0.38 tph and	[redacted]	Vendor budgetary quote
Byproduct disposal (Landfill)			1.1 tph and		Vendor budgetary quote
Auxiliary and ID fan power			795 kW and		2020 DU weighted average costs
Water			7,224 gph and		Mass balance calc. and DU cost
Total variable annual costs					
Total direct annual costs (DAC)					
Indirect Annual Costs					
Administrative charges (G&A, property tax, and insur.)	[redacted]	(TCI) X	[redacted]	Cost Manual, Section 5 SO_2 Controls, 1.3.4.2	
Cost for capital recovery		(TCI) X		[redacted]	
Total indirect annual costs (IDAC)					
Total Annual Cost (TAC) = (DAC) + (IDAC)	[redacted]				
		$/ton SO_2			

Figure B-6 SDA Annual Costs Calculations

Direct Costs		
Purchased equipment costs	[redacted]	Vendor Quotes (Andritz, B&W, and Tri-Mer)
CDS vessels	---	Included with vendor quote
Flue gas recirculation system	---	Included with vendor quote
Humidification water system	---	Included with vendor quote
Common fluidizing air system	---	Included with vendor quote
Reagent prep systems: silo, rotary feeders, and conveyair systems	---	Included with vendor quote
Byproduct recirculation system: fluidization slides, rotaryfeeders, etc.	---	Included with vendor quote
Common byproduct storage system, silo, rotary feeder, pug mill, etc.	---	Included with vendor quote
Interconnecting ductwork	---	Included with vendor quote
Six new PJFF systems, including casing	---	Included with vendor quote
Compartment inlet/outlet dampers	---	Included with vendor quote
Bags and cages	---	Included with vendor quote
Pulse air headers and control system	---	Included with vendor quote
New stacks	---	Included with vendor quote
ID fans, Motors, VFDs	---	Included with vendor quote
Subtotal capital cost (CC)	[redacted]	
Taxes	Excluded	
Freight	Incl. with Equip. Costs	
Total purchased equipment cost (PEC)	[redacted]	
Direct installation costs		
Foundation & supports	[redacted]	Engineering Estimator
Structural steel		Engineering Estimator
Handling & erection		Engineering Estimator
Electrical		Engineering Estimator
Piping		Engineering Estimator
Insulation		Engineering Estimator
Painting		Engineering Estimator
Instrumentation and controls		Engineering Estimator
Total direct installation costs (DIC)		
Site preparation	[redacted]	Engineering Estimator
Buildings		Engineering Estimator
Total direct costs (DC) = (PEC) + (DIC)		
Indirect Costs		
Engineering	[redacted]	Engineering Estimator
Construction and field expenses		Engineering Estimator
Owner's cost		Engineering Estimator
Start-up		Engineering Estimator
Performance test		Engineering Estimator
Contingencies		Engineering Estimator
Total indirect costs (IC)		
Allowance for Funds Used During Construction (AFDC)	[redacted]	[(DC)+(IC)] X [redacted] for 1 year(s)
Total Capital Investment (TCI) = (DC) + (IC)	[redacted]	

Figure B-7 CDS Capital Costs Calculations

ANNUAL COST					
Direct Annual Costs		Cap. Factor	39.0%	Cumulative coal consumption limit PTE basis	
Fixed annual costs					
Operating labor	[redacted]	6 FTE and	[redacted]	Estimated manpower level	
Maintenance labor		1.1 x	Operating Labor	Per EPA Cost Manual	
Maintenance materials		1 x	Maintenance Labor	Per EPA Cost Manual	
Total fixed annual costs					
Variable annual costs					
Reagent: Hydrated Lime	[redacted]	0.60 tph and	[redacted]	Vendor budgetary quote	
Byproduct disposal (Landfill)		1.1 tph and		Vendor budgetary quote	
Water		7,209 gph and		Mass balance calc. and DU cost	
Auxiliary and ID fan power		1,230 kW and		2020 DU weighted average costs	
Total variable annual costs					
Total direct annual costs (DAC)					
Indirect Annual Costs					
Administrative charges (G&A, property tax, and insur.)	[redacted]	(TCI) X	[redacted]	Cost Manual, Section 5 SO_2 Controls, 1.3.4.2	
Cost for capital recovery		(TCI) X		[redacted]	
Total indirect annual costs (IDAC)					
Total Annual Cost (TAC) = (DAC) + (IDAC)	[redacted]	\$/ton SO_2			

Figure B-8 CDS Annual Costs Calculations

Direct Costs (DC)		
Purchased equipment costs		
DSI system (blowers, silos, mills, lances)	[redacted]	Engineering estimate
Piping	---	Engineering estimate
Structural Steel	---	Engineering estimate
Electrical equipment	---	Engineering estimate
Misc. equipment	---	Engineering estimate
Subtotal capital cost (CC)	[redacted]	
Taxes	Excluded	
Freight	Incl. with Equip. Costs	
Total purchased equipment cost (PEC)	[redacted]	
Direct installation costs		
Foundations	[redacted]	Engineering estimate
Structural Steel		Engineering estimate
Piping		Engineering estimate
Electrical and Controls		Engineering estimate
Total direct installation costs (DIC)		
Sitework	[redacted]	Engineering estimate
Buildings		Engineering estimate
Total direct costs (DC) = (PEC) + (DIC)		
Indirect Costs		
Engineering	[redacted]	Engineering Estimator
Start-up		Engineering Estimator
Owner's Cost		Engineering Estimator
Contingencies		Engineering Estimator
Total indirect costs (IC)		
Allowance for Funds Used During Construction (AFDC)	[redacted]	[(DC)+(IC)] X [redacted]
Total Capital Investment (TCI) = (DC) + (IC)	[redacted]	

Figure B-9 DSI Capital Costs Calculations

ANNUAL COST					
Direct Annual Costs		Cap. Factor	39.0%	Cumulative coal consumption limit PTE basis	
Fixed annual costs					
Operating labor	[redacted]	1	FTE and	[redacted]	Estimated manpower level
Maintenance labor		1.1	x	Operating Labor	Per EPA Cost Manual
Maintenance materials		1	x	Maintenance labor	Per EPA Cost Manual
Total fixed annual costs					
Variable annual costs					
Reagent	[redacted]	1.3	ton/hr	[redacted]	Solvay budgetary quote
Water		21,600	gal/day		DU direction
Sewer cost		21,600	gal/day		DU direction
Auxiliary power		708	kW and		2020 DU weighted average costs
Solids disposal		1.0	ton/h		Differential cost for offsite disposal
Total variable annual costs					
Total direct annual costs (DAC)					
Indirect Annual Costs					
Administrative charges	[redacted]	[redacted]			
Cost for capital recovery, 30 year lifetime		(TCI) X	[redacted]	[redacted]	
Total indirect annual costs (IDAC), 10 year life					
Total Annual Cost (TAC) = (DAC) + (IDAC), 10 year life	[redacted]	$/ton SO2			

Figure B-10 DSI Annual Costs Calculations

Appendix C. [redacted]

[redacted]

Appendix D. **Vendor Quotes**

See vendor quotes attached for:

[redacted]

Appendix E. **Vendor Correspondence**

The attached archives include relevant email chains between B&V and six vendors for SO_2 control technologies. [redacted]

Appendix F. Ice Fog Monitoring and Suppression

The attached documents detail existing safety concerns regarding ice fog at the CHPP and Fort Wainwright, Alaska. The concerns were initially focused towards the cooling ponds at the facility but may be relevant in the discussion of additional moisture from the wet stack from new SO_2 control technologies.

Appendix G. Davis-Bacon Labor Rate for Alaska

The attached table summarizes the overall hourly rate for skilled labor in the state of Alaska. The data in this table reflects the up-to-date values provided from the 2021 Davis-Bacon data released in WD # AK20210001 and is accessible at SAM.gov.

Table G-2 Davis-Bacon Labor Rates for Skilled Labor in Alaska, 2021

TRADE DESCRIPTION	ADDITIONAL DESCRIPTION	BASE	FRINGES	SUBTOTAL	OVERTIME	TOTAL
BOILERMAKER		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MILLWRIGHT		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ELECTRICIAN		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 1A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 1A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POWER EQUIPMENT OPERATOR	GROUP 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IRONWORKER	BRIDGE, STRUCTURAL, ORNAMENTAL, REINFORCING MACHINERY MOVER, RIGGER, SHEETER, STAGE RIGGER, BENDER OPERATOR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LABORER	GROUP 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LABORER	GROUP 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LABORER	GROUP 3A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LABORER	GROUP 3B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LABORER	GROUP 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LABORER	GROUP 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LABORER	GROUP 3A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LABORER	GROUP 3B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PLUMBER; STEAMFITTER		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PLUMBER; STEAMFITTER		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PLUMBER; STEAMFITTER		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TRUCK DRIVER	GROUP 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TRUCK DRIVER	GROUP 1A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TRUCK DRIVER	GROUP 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
					AVERAGE:	[redacted]

DOYON UTILITIES LLC

714 Fourth Avenue, Suite 100 • Fairbanks, AK 99701
PO Box 74040 • Fairbanks, AK 99707
Phone (907) 455-1500 • Fax (907) 455-6788

June 2, 2022

Alice Edwards (via email alice.edwards@alaska.gov)
Alaska Department of Environmental Conservation
Division of Air Quality
PO Box 111800
Juneau, Alaska 99811

Re: Doyon Utilities Best Available Control Technology Study - Confidentiality Notice

Dear Ms. Edwards:

Doyon Utilities (DU) recently was made aware that the Alaska Department of Environmental Conservation (ADEC) anticipated publishing materials relating to Doyon Utilities' Best Available Control Technology (BACT) for SO_2 emissions at our Ft. Wainwright Central Heat and Power Plant (FWA CHPP). Thank you for providing DU the opportunity to respond.

In 2020, the Alaska Department of Environmental Conservation published its Serious SIP, which recognized in relevant part that dry sorbent technology (DSI) was the BACT for DU's FWA CHPP. On review, EPA was unsure that DSI met BACT. DU undertook a study to determine whether DSI was BACT. The results of the draft and final study were provided to EPA. The limited purpose of conducting and sharing the study was a BACT determination; to that end, certain information was provided to support the conclusion of that study. The study itself was commissioned by DU and ownership of the data and the report remains with DU. The contractor who performed the study entered into a nondisclosure agreement and does not have the authority to consent to disclosure.

The provided information is highly sensitive and is confidential, proprietary, a trade secret held by DU, covered defense information, confidential business information, subject to the provision of confidentiality or non-disclosure agreements, exempt from disclosure under 5 USC 552(b), or required to be kept confidential by other law or regulation. Without regard to laws, however, some of the information provides a view into critical infrastructure that persons with hostile intent could attempt to use against DU and/or the applicable United States military installation.

DU provides notice that DU's August 25, 2021 BACT Study cover letter and report including Appendices A, B, C, D, E, and G (excepting Appendix F incorporating published studies regarding ice fog) are proprietary and confidential business information of DU or are otherwise shielded from public disclosure. These disclosure limitations include but are not limited to protections for Covered Defense Information (CDI) and for information that falls under an appropriate category in the CUI registry but has not been bannered by the governing agency. *40 CFR 2.201; 40 CFR 2.208; 5 USC 552(b); 48 CFR 252.204-7012; 32 CFR 2002.20(a)(7).*

In the spirit of assisting ADEC with their future rulemaking, and without otherwise waiving any rights of confidentiality, intellectual or business property ownership, limits of release, or otherwise, DU consents to ADEC's publication of the following documents for its upcoming rulemaking, only if redacted as attached:

- 08.25.21 Wainwright SO2 Cover Letter (redacted)
- DU SO2 Reduction Analysis Report 8_25_2021 (redacted)

Please advise if this notice is insufficient or unclear, or if DU must take additional or other steps to confirm sufficient notice of confidentiality and ensure limitations on disclosure of unredacted documents outside of ADEC. Thank you for your consideration and assistance.

This letter is provided for discussion and notification purposes with ADEC, and not for further disclosure or as public comment.

Sincerely,

Shayne Coiley

Shayne Coiley
Senior Vice President
Doyon Utilities

Attachments: 08.25.21 Wainwright SO2 Cover Letter (redacted)
DU SO2 Reduction Analysis Report 8_25_2021 (redacted)

cc: Jim Plosay, ADEC
Kathleen Hook, DU

CO 22-034