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

1. Overview/Purpose

40 CFR §51.308(f)(2)(i) of the RH Rule requires states to submit plans for improvement that include enforceable emissions limits, compliance schedules, and other measures necessary to make reasonable progress towards natural visibility conditions at Class I areas. To achieve these goals, states are required to develop a LTS that must "include emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress'' and "identify all anthropogenic sources of visibility impairment considered by the state in developing its long-term strategy". In developing these goals, the state is to select sources and consider four factors when evaluating for potential control measures for the selected sources: 1) cost of compliance; 2) time necessary for compliance; 3) energy and non-air quality environmental impacts; and 4) remaining useful life. Consideration of visibility benefits is an optional fifth factor that states may consider per EPA's August 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period."

DEC used a two-step approach to select sources for evaluation. The initial step (step one) involved an AOI and WEP analysis, which was followed by a final Q/d analysis (step two) to select sources for evaluation under the four factors. In step one, DEC initially identified twenty-six point and area sources using the WEP analysis identified in Section 2a. In step two, DEC refined the list to six point sources subject to analyses using the Q/d analysis outlined in Section 2e. Of the six point sources; one facility had a four-factor analysis conducted, two facilities were partially evaluated with on-going four-factor analyses pending if existing emissions units (EUs) aren't retired, and three facilities were not evaluated because they recently went through a Best Available Control Technology (BACT) analysis for the Fairbanks North Star Borough (FNSB) Serious $PM_{2.5}$ nonattainment area. A list of the final six sources selected for evaluation are shown in Table III.K.13.F-1.

Table III.K.13.F-1. Facility Selection for Review

Facility	Review Section
North Pole Power Plant	3a
Healy Power Plant	3b
Chena Power Plant	3c
Eielson Air Force Base	3d
Fort Wainwright	3e
Fairbanks Campus Power Plant	3f

2. Source Selection

a. Why the Focus on Sulfur Dioxide (SO_2) in the Four Factor Analysis?

EPA guidance[1] allows for the elimination of pollutants from consideration in a four-factor analysis. States can focus on the PM species that "dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors". Further, EPA guidance states that it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of emissions of the dominant pollutants.

The selection of sources in Alaska to undergo a four-factor analysis was based solely on SO_2 emissions. SO_2 is a precursor pollutant of sulfate which dominates visibility impairment at Alaska Class I areas as shown in Figure III.K.13.F-2 and Section III.K.13.D. Other pollutants represent a smaller percentage of overall visibility impairment readings at the IMPROVE monitors. Sulfate domination is even more evident (> 95%) in the annual extinction composition attributable to human-caused pollution (Figure III.K.13.F-3). As in the first RH planning period, elimination of less important haze species allows for focus on the most influential species by state regulators. Given the dominance of sulfate to visibility at Alaska Class I areas, DEC elected to focus on SO_2 sources in the four-factor analysis.

Sources of SO_2 can be from natural or anthropogenic origins as described in Section III.K.13.E. Important natural SO_2 sources are volcanoes and oceanic DMS. Uncontrollable anthropogenic sources of SO_2 come from international industry operations including energy production, and marine shipping. In Alaska, anthropogenic SO_2 comes primarily from electrical generation and oil and gas development.

---

[1] Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, U.S. Environmental Protection Agency, EPA-454/R-18-010, December 2018. Page 12, Step 3.a

Figure III.K.13.F-2. Average extinction on the 2014-2018 MID at DENA1 and SIME1

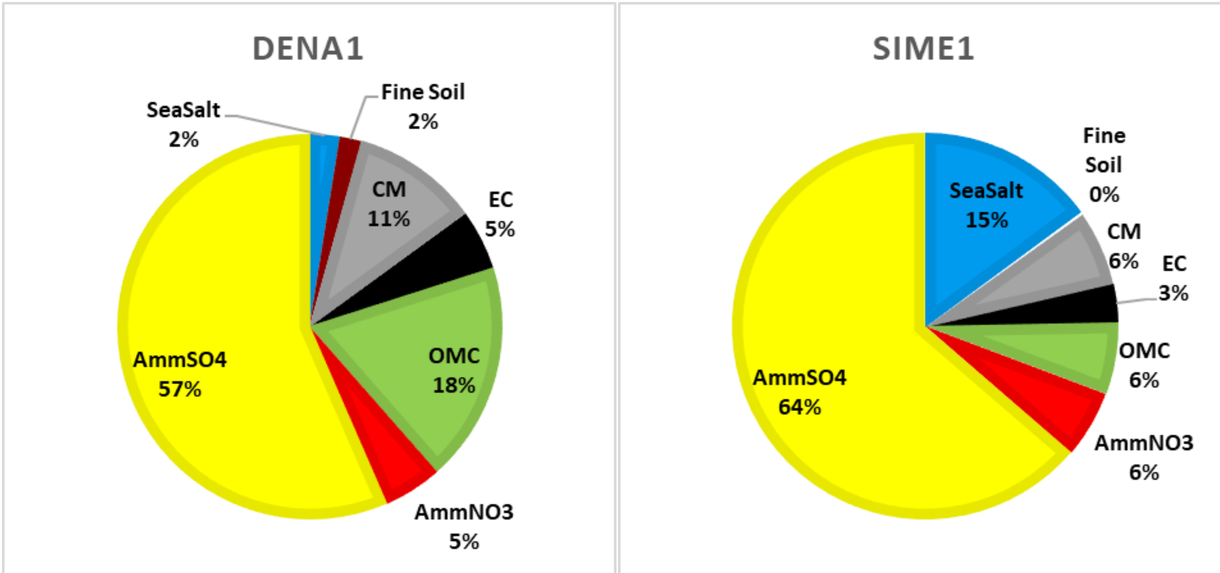
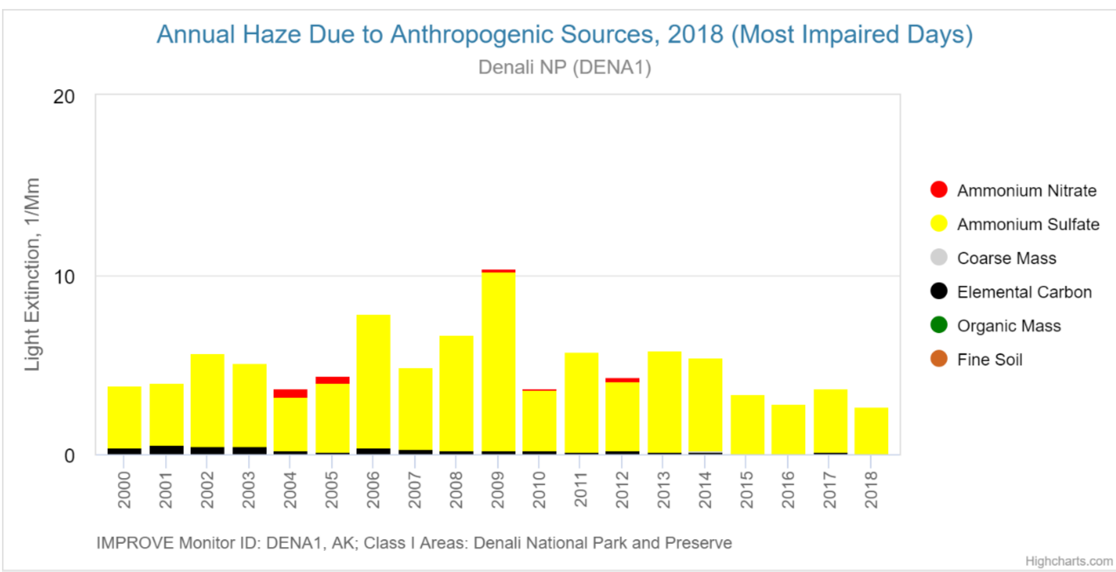
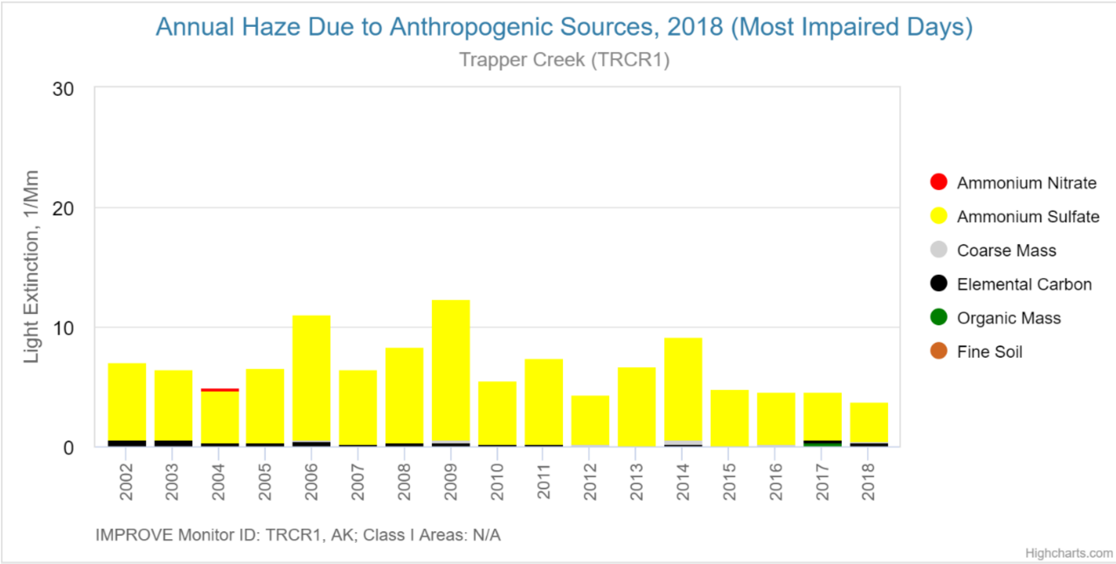
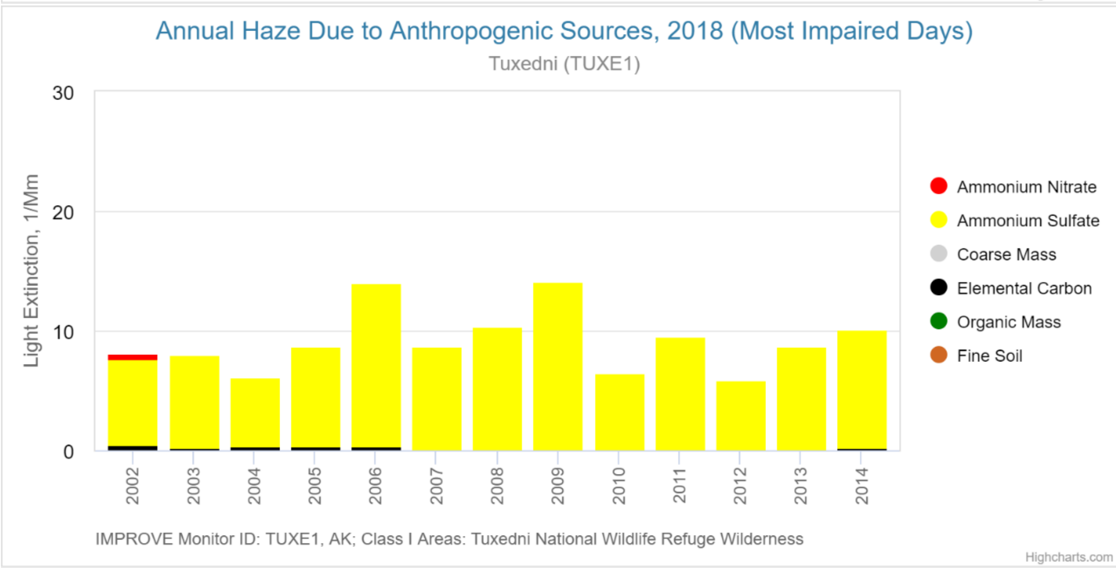


Figure III.K.13.F-3 Extinction on the 2002-2018 MID attributable to anthropogenic sources

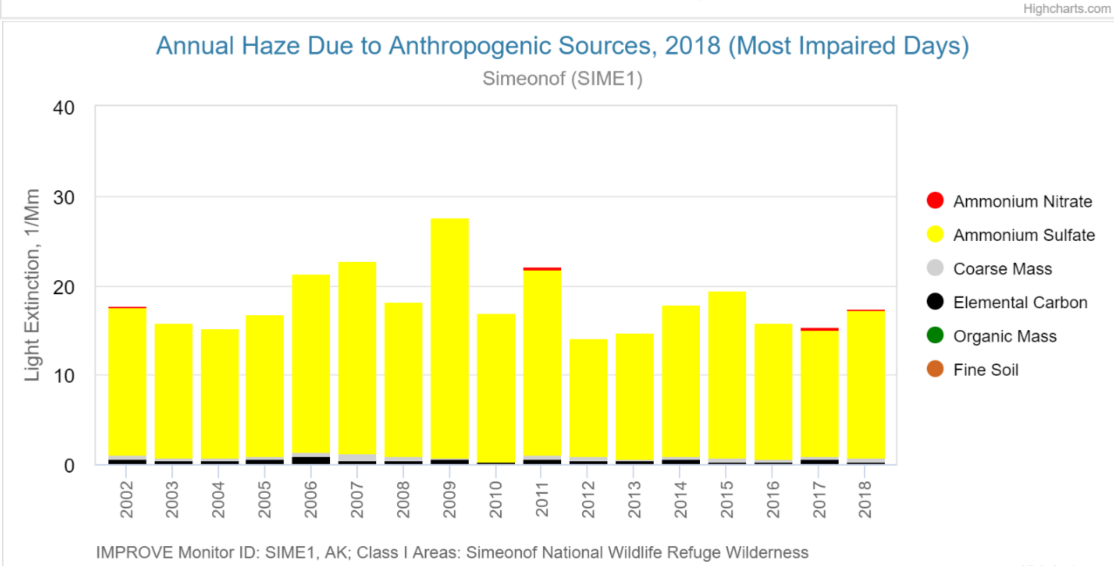




Annual Haze Due to Anthropogenic Sources, 2018 (Most Impaired Days)
Trapper Creek (TRCR1)
Light Extinction, 1/Mm
30
20
10
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Ammonium Nitrate
Ammonium Sulfate
Coarse Mass
Elemental Carbon
Organic Mass
Fine Soil
IMPROVE Monitor ID: TRCR1, AK; Class I Areas: N/A
Highcharts.com



Annual Haze Due to Anthropogenic Sources, 2018 (Most Impaired Days)
Tuxedni (TUXE1)
Light Extinction, 1/Mm
30
20
10
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Ammonium Nitrate
Ammonium Sulfate
Coarse Mass
Elemental Carbon
Organic Mass
Fine Soil
IMPROVE Monitor ID: TUXE1, AK; Class I Areas: Tuxedni National Wildlife Refuge Wilderness
Highcharts.com



Annual Haze Due to Anthropogenic Sources, 2018 (Most Impaired Days)
Simeonof (SIME1)
Light Extinction, 1/Mm
40
30
20
10
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Ammonium Nitrate
Ammonium Sulfate
Coarse Mass
Elemental Carbon
Organic Mass
Fine Soil
IMPROVE Monitor ID: SIME1, AK; Class I Areas: Simeonof National Wildlife Refuge Wilderness
Highcharts.com

b. Source Selection Strategy: Step One (WEP Analysis) Overview

Many states are selecting sources for review and analysis using the Q/D method (quantity of actual emissions in tons per year divided by distance in kilometers to the IMPROVE monitor) to apply to point sources of NO_x and of SO_2. In Alaska, the Q/D source selection was based on the parameters in the WRAP tool[2]. The WRAP Q/D Tool establishes a threshold of 10 tons per year per km (tpy/km) for Q/D and 25 tpy for Q and only facilities with a distance less than 400 km were included. As noted in the EPA Guidance, the Q/D methodology does not take into consideration topography, transport direction/pathway and dispersion, and photochemical processes.

Alaska contracted with Ramboll to run HYSPLIT back trajectories to develop AOI and WEP for each Class I area. While the WEP analysis includes facility point and other anthropogenic sources (e.g., nonpoint facilities, mobile sources), only point sources are considered for a full four factor analysis. A complete analysis of the HYSPLIT modeling and WEP analysis are presented in Section III.K.13.G (Modeling). In short, the modeling used facility emissions from the National Emissions Inventory (NEI) for 2014 and 2017 and ranked facilities by their potential contributions to the WEP SO_4. The benefit of using two emission inventory years is that it provides ranges of emissions and an opportunity to identify changes in point source emissions that can be used in sector projections. Alaska used these rankings to determine the sources that are most likely contributing to visibility impairment. Alaska is already very close to natural visibility in the Class I areas; more information on current monitoring data can be found in Section III.K.13.D and for the long-term strategy in Section III.K.13.I. By focusing on sources that are likely to have the highest impact on Class I areas, any control measures implemented would theoretically result in the most reductions of impairment.

The analysis focuses on the IMPROVE MID from 2014 to 2018 at the IMPROVE sites representing Class I areas in the state, with exception of those at Tuxedni Class I area. TUXE1 site stopped operating in 2014 so the MID from 2012 to 2014 were used instead of the 2014-2018 period. The KPBO1 IMPROVE monitor started operating in 2016 and was not included in the analysis of MID as no impairment metric data is available for the site. Instead, the WEP analysis was performed for the top 20% measured visibility extinction days (Top 20%) at TUXE1 and KPBO1 for the 3 most recent years of available data (2012 to 2014 and 2016 to 2018, respectively. Table III.K.13.F-4 identifies the years of the analysis period and the analyzed metric for each IMPROVE site.

---

[2] Regional Haze Four-factor Analysis Screening tool developed by Ramboll. http://views.cira.colostate.edu/data/tss/ramboll/WRAP_Q_Over_D_Analyses/WRAP_Threshold_Analysis.xlsm

Table III.K.13.F-4. Alaska Class I Areas and IMPROVE monitoring sites included in the Area of Influence and Weighted Emissions Potential analysis

Class I Area	IMPROVE Site	Analysis Period	Analyzed Metric
Denali National Park and Preserve	DENA1	2014 - 2018	MID
	TRCR1	2014 - 2018	MID
Simeonof Wilderness Area	SIME1	2014 - 2018	MID
Tuxedni National Wildlife Refuge	TUXE1	2012 – 2014	MID, Top 20%
	KPBO1	2016 – 2018	Top 20%

c. Step One Methods Used for Initial Source Selection

Step 1a: Identify areas of high WEP

For each Class I area, images of the WEP generated from all analysed altitudes (i.e., 100 m, 200 m, 500 m, and 1,000 m) are examined, and the areas with SO_x WEP values of 5 percent (%) or more are identified. The highest WEP percentage does not point to a specific facility but rather an area where a variety of sources may potentially influence a Class I area. This occurs in Cook Inlet and in the FNSB. For any facility within the WEP area of 5% or greater, its location is confirmed using the corresponding DEC issued permits, and it then gets included in the selected sources.

Step 1b: Point Source Facility Selection

DEC ranked source facilities by WEP SO_4 values. Generally, there is a sharp decline in WEP values that separate major contributing sources from the rest. Table III.K.13.F-5 demonstrates this situation for the Denali Class I area where the steep decline from the WEP SO_4 rankings from approximately 4000 to less than a 1000 that could be used as a logical cutoff point for facility consideration. Only the highest emitting facilities above this cutoff are selected given that they are also located within the 5% WEP area described in Step 1a. It is possible that the WEP areas (Step 1a) do not match with any of the highest emitting facilities and in that case, additional facilities can be considered.

An additional step is used to identify facilities with extensive emission changes that may warrant further consideration related to their potential impacts. These can be seen when a facility appears in 2014 and is no longer listed in 2017. A review of permits issued by DEC is used to see if there are substantial changes at that facility. An example of this is Clear Air Force Station (Clear AFS). The point source emissions in 2014 included use of coal in their electrical generation units. By 2017, they had contracted to purchase electricity, and their emissions had been drastically reduced. In all cases, 2017 inventories are considered closer to potential future emissions.

Table III.K.13.F-5. Ranked point facilities by WEP SO_4 at DENA1

	2014 Point Source Facilities	SO_2 emissions (Q, tpy)	Q/D (tpy/km)	EWRTxQ_SO4	WEP SO_4
1	Healy Power Plant	444.94	31.69	13,644,281	971,737
2	Clear Air Force Station	213.21	3.34	3,275,622	51,286
3	Chena Power Plant	655.00	4.75	2,171,173	15,784
4	Fort Wainwright (EGU)	654.74	4.76	2,172,035	15,753
5	Eielson Air Force Base	268.05	1.93	1,002,245	7,203
6	UAF Campus Power Plant	201.99	1.48	669,816	4,896
7	GVEA North Pole Power Plant	148.37	1.09	554,759	4,063
8	TAPS PS #07	25.77	0.14	1212	175
	2017 Point Source Facilities	**SO_2 emissions (Q, tpy)**	**Q/D (tpy/km)**	**EWRTxQ_SO4**	**WEP SO_4**
1	Healy Power Plant	296.40	21.11	9,089,280	647,333
2	Chena Power Plant	627.60	4.55	2,081,175	15,094
3	Fort Wainwright UGU	460.04	3.34	1,525,532	11,090
4	Eielson Air Force Base	262.81	1.89	982,647	7,062
5	GVEA North Pole Power Plant	247.24	1.81	924,430	6,770
6	UAF Campus Power Plant	163.81	1.20	543,224	3,971
7	GVEA Zehnder Facility	29.56	0.21	98,019	706

Step 1c: Nonpoint Facility Selection

The ranked source lists include permitted facilities that were reported to EPA in the nonpoint category. If they are close to a Class I area, the contribution can still be significant. For example, the Trident Seafoods Sand Point facility emitted 0.089 tons of SO_2 in 2017 but because of its proximity to the SIME1 IMPROVE monitor, it has the highest WEP SO_4 in the ranked facility list (Table III.K.13.F-6). The second highest was the Steelhead Platform, which emitted approximately 44.7 tons of SO_2 in 2017. The Steelhead Platform's WEP SO_4 was significantly lower because of its distance from the Class I area. As such, the Sand Point Facility and Steelhead Platform are advanced to the second step of DEC's source selection criteria.

In most cases, sources can be identified in the areas with SO_x WEP of 5% or more. In some cases, no single point, nonpoint, nonroad, or mobile source can be identified. For example, east of the KPB01 IMPROVE monitor and in Western Anchorage and north of Anchorage, there are three locations identified with a WEP of 5% or greater. In this specific example, the point sources located in the WEP area that may be contributors are low on the ranking of individual source WEP (see Step 1b) so there could be multiple contributing sources.

DEC looked at the permit locations with relation to the WEP area to resolve some of these questions. In some cases, DEC determined that the emissions are from nonroad and area sources such as airstrips, railroad, and marine port facilities which will be addressed on a sector basis. For SIME1 in particular, the number of sources available for Q/d and WEP analysis are limited to sources like Trident Seafood with a small emissions profile.

Table III.K.13.F-6. SIME1 2017 Point Facilities With Highest WEP

	Facility Name	SO_2 emissions (Q, tpy)	Q/D (tpy/km)	EWRTxQ_SO4	WEP SO_4
1	Trident Seafoods; Sand Point Facility	0.089	0.073	7,350.4	6,048
2	Hilcorp - Steelhead Platform	44.7	0.055	54,302.0	67.3

Step 1d: Compiling the Source list Selection

A master list was compiled after applying Steps 1a – 1c and includes those sources that appear at more than one IMPROVE monitor. For facilities that appear at more than one IMPROVE monitor it is assumed that emission controls could result in improved visibility at more than one Class I area.

Sources that have a high WEP value in 2017 that do not appear in >5% WEP selection criteria are included. The master list of sources that are advanced to Step Two are found in Table III.K.13.F-7.

d. Step One Preliminary Source Selection Results

Table III.K.13.F-7 identifies the sources identified in the Step One WEP analysis that are advanced to the Step Two Q/d analysis for final selection. The criteria used for each source selection is also noted as well as where the location of the final review for the source is located between this chapter for sources that were selected after Step Two and the appendix of this chapter for sources that were not advanced beyond Step Two. For point sources selected because of their ranking on the WEP SO_4 (either based on 2014 or 2017 emissions or both) the criteria are shown as 'Rank point YEAR'. For source sectors selected because they are within the 5% WEP area for the MID, the criteria are listed as 'MID WEP' (or 'Top 20% WEP for KPBO1).

Table III.K.13.F-7. Preliminary Facility Selection From Step One

	Sector	Facility	Denali		Simeonof	Tuxedni		Review Section Location
			DENA1	TRCR1	SIME1	KPB01	TUXE	
1	Power Plant	GVEA North Pole Power Plant	Rank point 2014/2017					III.K.13.F 3a

2	Power Plant	Healy Power Plant*	Rank point 2014/2017	Rank point 2014/2017				III.K.13.F 3b
3	Power Plant	Chena Power Plant	Rank point 2014/2017					III.K.13.F 3c
4	Nat. Security	Eielson Air Force Base	Rank point 2014/2017					III.K.13.F 3d
5	Power Plant	Fort Wainwright EGU	Rank point 2014/2017					III.K.13.F 3e
6	Power Plant	UAF Power Plant	Rank point 2014/2017					III.K.13.F 3f
7	Nat. Security	Clear Air Force Base	Rank point 2014					III.K.13.F Appendix 2a
8	Manufact./ Seafood Process.	Trident Seafoods - Sand Point Facility			Rank point 2014/2017		Rank point 2014 (MID)	III.K.13.F Appendix 2b
9	Oil & Gas	Christy Lee/Drift River					Rank point 2014/2017 (MID)	III.K.13.F Appendix 2c
10	Power Plant	Bernice Lake Combustion Plant		Rank point 2014		Rank point 2014 (Top 20%)		III.K.13.F Appendix 2d
11	Power Plant	JBER-Electric, Gas, Drinking Water & Sanitary Services						III.K.13.F Appendix 2e
12	Power Plant	Matanuska Electric - Eklutna EGU						III.K.13.F Appendix 2f
13	Oil & Gas	Platform A		Rank point 2014		Rank point 2014 (Top 20%)		III.K.13.F Appendix 2g
14	Oil & Gas	Monopod Platform		Rank point 2014		Rank point 2014 (Top 20%)	Rank Point 2014 (MID, Top 20%)	III.K.13.F Appendix 2h

15	Oil & Gas	Grayling Platform		Rank point 2014		Rank point 2014 (Top 20%)	Rank Point 2014 (MID, Top 20%)	III.K.13.F Appendix 2i
16	Oil & Gas	Dolly Varden Platform		Rank point 2014/2017		Rank point 2014 (Top 20%)	Rank point 2014/2017(MID, Top 20%)	III.K.13.F Appendix 2j
17	Oil & Gas	King Salmon		Rank point 2014		Rank point 2014 (Top 20%)	Rank Point 2014 (MID, Top 20%)	III.K.13.F Appendix 2k
18	Oil & Gas	Steelhead		Rank point 2017			Rank Point 2017 (MID, Top 20%)	III.K.13.F Appendix 2l
19	Oil & Gas	BlueCrest Cosmopolitan				Rank point 2017 (Top 20%)		III.K.13.F Appendix 2m
20	Transport,	Ted Stevens International (ORL)		MID WEP		Top 20% WEP	Top 20% WEP	III.K.13.F Appendix 3a
	Transport	Ted Stevens International (Aviation Non-Point)		MID WEP		Top 20% WEP	Top 20% WEP	III.K.13.F Appendix 4h
21	Transport	Port of Anchorage (ORL)		MID WEP				III.K.13.F Appendix 3b
	Transport	Port of Anchorage (Marine Sector)		MID WEP				III.K.13.F Appendix 4a
22	Transport	Port McKenzie		MID WEP				III.K.13.F Appendix 4g
23	Transport	Trapper Creek Aviation		MID WEP				III.K.13.F Appendix 4i
24	Transport	Homer Aviation, Port		MID WEP		Top 20% WEP		III.K.13.F Appendix 4j, 4k, & 4l
25	Transport	Ninilchik		MID WEP		Top 20% WEP	Top 20% WEP	III.K.13.F Appendix 4m

26	Transport	Alaska Railroad		MID WEP				III.K.13.F Appendix 4c & 4n

e. Step Two Methods Used for Final Source Selection

After initial review of the 26 point and area sources identified in Step One, DEC determined that the list of point sources included numerous facilities with low actual SO_2 emissions that could not meaningfully be lowered any further. This included sources such as Trident Seafoods Sand Point Facility and Clear Air Force Base with SO_2 emissions below 0.1 tpy as well as multiple sources combusting ULSD, pipeline quality natural gas, and/or low sulfur fuel gas in the Cook Inlet area that had over-reported their actual SO_2 emissions in the 2014 NEI. Therefore, DEC included a second step (Step Two) to ensure that only the sources who are potentially contributing to haze in Class I areas and have a potential to reduce their actual SO_2 emissions would be evaluated.

For Step Two DEC used a Q/d approach as outlined in Footnote 25 and Section II.B.3.b of the August 20, 2019, Guidance on Regional Haze document (Guidance Document). The Guidance Document outlines that instead of quantifying and considering visibility impacts for the purpose of selecting sources, a state may also develop a reasonable surrogate metric for such impacts (e.g., the emissions/distance relationship). This approach involves a stationary source's actual emissions in tons per year (Q) divided by the distance to the nearest Class 1 area in kilometers (d). As was previously stated, the NEI for 2014 involved multiple sources over-reporting their actual SO_2 emissions and is more outdated than 2017 (e.g., Clear Air Force Base has since retired their coal-fired boilers). Therefore, DEC chose to use the SO_2 values reported in the 2017 NEI in the Step Two Q/d analysis as that is more representative of current and future emissions.

For Step Two, DEC chose an SO_2 Q/d threshold of 1.0 for stationary sources. As a result, all stationary sources with 2017 NEI reported SO_2 emissions values divided by distance to the nearest Class 1 area of 1.0 and above made is past this step to final evaluation. The Guidance Document states on page 13 that when using a Q/d surrogate for visibility impacts a "reasonably selected threshold for this metric" shall be used. The Guidance Document also goes on to state that, "since primary PM and PM precursors may have very different visibility impacts per ton of emissions, it may be best to evaluate Q/d metrics on an individual pollutant basis. Additionally, since the magnitude of Q/d may vary considerably when total emissions are considered versus emissions of individual primary PM and precursor pollutants, appropriate pollutant-specific Q/d thresholds for primary PM and each precursor may need to be considered as part of the analysis.

DEC has chosen an SO_2 Q/d of 1.0 and above as a reasonable surrogate threshold metric. The Guidance Document did not specify a minimum value to use for Q/d source selection and DEC notes that an SO_2 Q/d value of 1.0 should be considered conservative enough to capture all sources with SO_2 emissions that could meaningfully impact visibility in Class 1 areas. DEC notes that the Q/d threshold of 1.0 for SO_2 emissions is more conservative than the threshold of 10.0 for combined PM and precursor pollutants used in the Federal Land Managers' Air Quality Related Values Work Group (FLAG) 2010 Guidance Document for Prevention of Significant Deterioration permitting.

f. Final Source Selection

After completing the two-step source selection process for stationary sources in Alaska, DEC has identified the following list of six sources that warrant evaluation as can be seen below in Table III.K.13.F-8.

Table III.K.13.F-8. Final Facility Selection for Review

Facility	Nearest Monitor	Distance to Monitor – d (km)	Quantity of SO_2 Emissions – Q (tpy)	Q/d SO_2	Section Number
North Pole Power Plant	Denali N.P.	122	247.2	2.0	3a
Healy Power Plant	Denali N.P.	6	296.4	49.4	3b
Chena Power Plant	Denali N.P.	119	627.6	5.3	3c
Eielson Air Force Base	Denali N.P.	133	262.8	2.0	3d
Fort Wainwright	Denali N.P.	119	460.0	3.9	3e
Fairbanks Campus Power Plant	Denali N.P.	117	163.8	1.4	3f

DEC notes that the second step in the source selection process resulted in only selecting stationary sources that have impacts on Denali National Park. This was a result of the largest emitting stationary source near the Tuxedni National Wildlife Refuge (Hilcorp's Steelhead Platform) only having SO_2 emissions of 44.7 tons in 2017. Additionally, the largest emitting source near the Simeonof Wilderness Area (Trident Seafoods Akutan Seafood Processing Facility) only emitted 2.8 tons of SO_2 in 2017. DEC will continue to monitor emissions from stationary sources in Alaska which may result in additional sources nearer to Tuxedni National Wildlife Refuge or Simeonof Wilderness Area warranting full four-factor analyses in future rounds of RH. See Section III.K.13.H Long-Term Strategy for the approach identified for monitoring new sources or major changes in existing sources for addressing possible future impacts.

3. Four-Factor Analysis

a. Golden Valley Electric Association, North Pole Power Plant

i. Introduction

The NPPP is an electric generating facility owned and operated by GVEA that currently operates under Title V Operating Permit AQ0110TVP04 Rev. 1. The standard industrial classification (SIC) code for this stationary source is 4911 - Electric Services. The power plant contains two fuel oil-fired simple cycle gas combustion turbines, two fuel oil-fired combined cycle gas combustion turbines, one fuel oil-fired emergency generator, and two propane fired boilers. These EUs are listed below in Table III.K.13.F-9. The stationary source also owns insignificant EUs that include several gas-fired heaters.

Table III.K.13.F-9. Golden Valley Electric Association, North Pole Power Plant Emissions Units

EU ID	Emissions Unit Name	Emissions Unit Description	Fuel	Rating/Size	Installation or Construction Date
1	GT#1	GE Frame 7, Series 7001 Regenerative Gas Turbine	Fuel Oil	672 MMBtu/hr (60.5 MW)	1976
2	GT#2	GE Frame 7, Series 7001 Regenerative Gas Turbine	Fuel Oil	672 MMBtu/hr (60.5 MW)	1977
5	GT#3	GE LM6000PC Gas Turbine (water injection for NO_x control) (oxidation catalyst for CO control)	Naphtha/LSR Jet A	455 MMBtu/hr (43 MW, nominal)	2005
6	GT#4	GE LM6000PC Gas Turbine (water injection for NO_x control) (oxidation catalyst for CO control)	Naphtha/LSR Jet A	455 MMBtu/hr (43 MW, nominal)	Not Installed[1]
7	Emergency Generator	Mitsubishi Engine #0A8829 (Generac Gen Set #5231150100)	Fuel Oil	565 hp	2005
11	Building Boiler	Bryan Steam RV500 Boiler	Propane	5.0 MMBtu/hr	2005
12	Building Boiler	Bryan Steam RV500 Boiler	Propane	5.0 MMBtu/hr	2005

Table Notes: [1] Estimated installation is 2024.

The NPPP recently went through an emissions control analysis as a part of the planning requirements triggered when the FNSB nonattainment area was designated as “Serious” with respect to nonattainment of the 2006 24-hour $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS), which was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706. CAA section 189(b)(1)(B) and 40 C.F.R. § 51.1010 describe the Serious area attainment plan requirements for best available control measures (BACM). Large stationary sources are a subgroup of emissions sources that are given special attention in the required BACM analysis (large stationary sources are subject to best available control technologies or

BACT analyses). Per federal requirement, DEC evaluated all point sources with emissions greater than 70 TPY of $PM_{2.5}$ or for any individual $PM_{2.5}$ precursor (NO_x, SO_2, NH_3, VOCs).

This evaluation resulted in the following emissions controls contained in Table III.K.13.F-10, which are those required in Table 7.7-15 of the Amendments to: State Air Quality Control Plan Vol II: III.D.7.7 Control Strategies document; adopted November 19, 2019.[3]

Table III.K.13.F-10. Summary of BACT

Pollutant	BACT Emission Limit	BACT Control Device or Operational Limitation	Effective Dates of Control/Limit
EUs 1 and 2 Fuel Oil-Fired Simple Cycle Gas Turbines - 672 MMBtu/hr (each)			
NO_x	Precursor Demonstration*	No additional control	N/A
PM2.5	0.012 lb/MMBtu (3-hr avg.)	Low Ash Fuel, Limited Operation, and Good Combustion Practices	Existing
SO2	1,000 ppmw sulfur deliveries fuel on curtailment days	Certified Statement or Approved Analysis of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than October 1, 2020
	15 ppmw sulfur in fuel October 1 – March 31 (natural gas optional)	Certified Statement or Approved Analysis of Sulfur Content	Title I Permit App. by June 9, 2022 Effective no later than October 1, 2023
EUs 5 and 6 - Combined Cycle Gas Turbines - 455 MMBtu/hr (each)			
NO_x	Precursor Demonstration*	No additional control	N/A
PM2.5	0.012 lb/MMBtu (3-hr avg.)	Low Ash Fuel, Limited Operation, and Good Combustion Practices	Existing
SO2	50 ppmw sulfur in fuel (except during startup) (natural gas optional)	Certified Statement of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
EU 7 - Diesel-Fired Emergency Generator - 400 kW			
NO_x	Precursor Demonstration*	No additional control	N/A
PM2.5	0.32 g/hp-hr (3-hr avg.)	Good Combustion Practices, Positive Crankcase Ventilation, and Limited Operation	Existing

[3] Background and detailed information regarding Fairbanks $PM_{2.5}$ State Implementation Plan (SIP) can be found at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/.

Pollutant	BACT Emission Limit	BACT Control Device or Operational Limitation	Effective Dates of Control/Limit
SO2	0.05 weight percent sulfur in fuel	Certified Statement of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
EUs 11 and 12 - Propane-Fired Boilers 5.0 MMBtu/hr (each)			
NO_x	Precursor Demonstration*	No additional control	N/A
PM2.5	0.008 lb/MMBtu (3-hr avg.)	Good Combustion Practices and Propane as Fuel	Existing
SO2	120 ppmv sulfur in fuel	Certified Statement of Sulfur Content	Existing

The previously mentioned analysis for the NPPP resulted in multiple SO_2 emissions limits. The requirement to combust fuel with a maximum sulfur content of 1,000 ppmw in EUs 1 and 2 on curtailment days has already gone into effect. Meanwhile, additional sulfur limiting requirements will go into effect on June 9, 2021, and October 1, 2023, such as requiring ULSD be combusted in EUs 1 and 2 from October 1 through March 31.

DEC compiled a list of SO_2 emissions at the stationary source using the EI submissions for years 2014-2019 which can be seen in Table III.K.13.F-11. As can be seen in Table III.K.13.F.11, EUs 1, 2, and 5 are the only EUs with sizeable SO_2 emissions over the past 6 years. Additionally, as can be seen in Table III.K.13.F-10 above, emergency diesel generator EU 7 has a new requirement to burn fuel with a maximum of 0.05 weight percent sulfur, and boiler EUs 11 and 12 are already required to burn propane, which is an inherently low sulfur fuel. Taking all of this into account, DEC has chosen to perform a four-factor analysis of the NPPP on EUs 1, 2, and 5. DEC has chosen to use the value from the highest actual emissions year, for each EU, for all cost analyses performed.

Table III.K.13.F-11. North Pole Power Plant SO_2 Emissions

Calendar Year	EU ID	SO_2 Emitted (tons) Emissions Inventory	SO_2 Emitted (tons) Emissions Inventory
2019	1	17.04	268.4
	2	251.03	
	5	0.32	
	7	0.00	
	11	0.00	
	12	0.00	
	1	19.8	
	2	189.84	

2018	5	5.58	215.2
	7	0.00	
	11	0.00	
	12	0.00	
2017	1	31.68	269.5
	2	228.87	
	5	8.89	
	7	0.00	
	11	0.00	
	12	0.00	
2016	1	37.87	239.8
	2	190.76	
	5	11.20	
	7	0.00	
	11	0.00	
	12	0.00	
2015	1	8.47	149.1
	2	131.74	
	5	8.84	
	7	0.00	
	11	0.00	
	12	0.00	
2014	1	5.64	148.4
	2	138.15	
	5	4.58	
	7	0.00	
	11	0.00	
	12	0.00	

ii. SO2 Four-Factor Analysis

Section 169A(g)(1) of the CAA lists four factors that must be taken into consideration in determining reasonable progress and states are required to consider those four factors (i.e., cost of compliance, time necessary for compliance, energy and non-air environmental impacts, and remaining useful life of the source) in the control analysis step.

1. Cost of Compliance for the Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

The cost of compliance estimates the values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions that have been prepared according to EPA's Air Pollution Control Cost Manual. Costs are expressed in terms of cost effectiveness in the standardized unit of dollars per ton of actual SO_2 emissions reduced. DEC used information from the BACT analyses completed for the Fairbanks Serious SIP for SO_2 to complete the cost of compliance analyses. This information included previous BACT determinations found in the RACT, BACT, & LAER Clearinghouse (RBLC) database; internet research; and BACT analyses submitted to DEC by GVEA for the NPPP and Zehnder Facility.

The RBLC was searched for all determinations in the last 10 years under the process code 15.190 for simple cycle gas turbines (rated at 25 MW or more) The search results for simple cycle gas turbines are summarized in Table III.K.13.F-12.

Table III.K.13.F-12. RBLC Summary of SO_2 Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits	
Ultra-Low Sulfur Diesel	7	0.0015	% S by wt.
Fuel Oil (0.1 % S by wt. or less)	2	0.0026 – 0.055	lb/MMBtu
Good Combustion Practices	3	0.6	lb/hr

a. RBLC Review

A review of similar units in the RBLC indicates that limiting the sulfur content of fuel and good combustion practices are the principle SO_2 control technologies determined as BACT for fuel oil-fired simple cycle gas turbines. The lowest SO_2 emission rate listed in the RBLC is combustion of ULSD at 0.0015 percent sulfur by weight (% S by wt.).

i. Identification of SO2 Control Technology for the Simple Cycle Gas Turbines

From research, DEC identified the following technologies as available for control of SO_2 emissions from fuel oil-fired simple cycle gas turbines rated at 25 MW or greater:

1. Ultra Low Sulfur Diesel (ULSD)

ULSD has a fuel sulfur content of 0.0015 % S by wt. or less. Using ULSD would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are mostly combusting No. 2 fuel oil that has a sulfur content averaging around 0.35 % S by wt. for half of the year (April 1 through September 31). Switching to ULSD for the other half of the year would result in around a 99.5 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines. DEC considers ULSD a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

2. No. 1 Fuel Oil (maximum sulfur content of 0.1 % S by wt.)

No. 1 fuel oil has a sulfur content of 0.1 % S by wt. (1,000 ppmw) or less. Using fuel with a sulfur content of 0.1 % S by wt. would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are mostly combusting No. 2 fuel oil that has a sulfur content of around 0.35 % S by wt. for half of the year (April 1 through September 31). Switching to No. 1 fuel oil would result in an approximate 67.5 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines. DEC considers low sulfur diesel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

b. Eliminate Technically Infeasible SO_2 Technologies for the Simple Cycle Gas Turbines

All control technologies identified are technically feasible for the fuel oil-fired simple cycle gas turbines.

c. Rank point the Remaining SO_2 Control Technologies for the Simple Cycle Gas Turbines

The following control technologies have been identified and ranked for control of SO_2 from the fuel oil-fired simple cycle gas turbines (Table III.K.13.F-13):

Table III.K.13.F-13. Control Technologies

Control Technology	Control Level
Ultra Low Sulfur Diesel	99.5% Control
No. 1 Fuel Oil	67.5% Control

Table Note: Control technologies already required at the stationary source, including burning ULSD for half the year and practicing good combustion practices, or those included in the design of the EU are considered 0% control for the purposes of this four-factor analysis.

d. Evaluate the Most Effective Controls

GVEA provided an economic analysis for the Serious SIP BACT exercise for switching the fuel combusted in the simple cycle gas turbines to ULSD. DEC used this cost analysis and an update provided by GVEA for the cost per gallon of ULSD, No. 1, and No. 2 fuel oils delivered to the NPPP between January 2019 and October 2020 to perform our cost analyses.

i. Department Evaluation of BACT for SO_2 Emissions from the Simple Cycle Gas Turbines

DEC's cost analyses calculated a cost per ton of SO_2 emissions removed resulting from a switch to ULSD. There is no capital cost involved with this fuel switch for EUs 1 and 2. Therefore, the only value driving cost for the evaluation was the yearly cost difference in fuel prices between No. 2 fuel oil compared to ULSD and No. 1 fuel oil. From January 2019 through October 2020, the average price per gallon of ULSD delivered to the NPPP was $1.918. This is $0.250 more per gallon than the cost of No. 2 fuel oil at 1.668. Note that during this same time period, the average price per gallon for No. 1 fuel oil was $1.618, which is $0.05 cheaper than No. 2 fuel oil. EUs 1 and 2 are already required to switch to ULSD (SO_2 BACT) for half of the year (October through

March). Therefore, the RH cost calculations used half of the total fuel used during the highest SO_2 emitting year as well as half of the total SO_2 emissions for that year.

A summary of these analyses is shown in Table III.K.13.F-14 and Table III.K.13.F-15.

Table III.K.13.F-14. Department Economic Analysis for Technically Feasible SO_2 Controls for EU 1

Control Alternative	2016 SO_2 Emissions (tons)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	18.94	18.85	N/A	$206,296	$10,946
No. 1 Fuel Oil	18.94	12.90	N/A	N/A	N/A
Capital Recovery Factor = 0.0 (There is no capital investment involved with this cost calculation)					

Table III.K.13.F-15. Department Economic Analysis for Technically Feasible SO_2 Controls for EU 2

Control Alternative	2019 SO_2 Emissions (tons)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	125.34	124.72	N/A	$1,420,905	11,393
No. 1 Fuel Oil	125.34	83.78	N/A	N/A	N/A
Capital Recovery Factor = 0.0 (There is no capital investment involved with this cost calculation)					

DEC's cost of compliance economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD for the fuel oil-fired simple cycle gas turbines at the NPPP ($11,393/ton). No. 1 fuel oil (maximum sulfur content of 0.1 percent by weight) costs approximately $0.05 per gallon less to purchase than No. 2 fuel oil from Petro Star, Inc.'s North Pole Refinery, and would result in approximately 13 less tons of SO_2 emissions from EU 1 in 2016 and 84 less tons of SO_2 emissions from EU 2 in 2019; for the highest emitting years reviewed for the respective turbines. No. 1 fuel oil contains a slightly lower fuel heat content of 133.4 MMBtu/kgal compared to No. 2 fuel oil at 138.3 MMBtu/kgal as reported by GVEA in the 2019 NEI.[4] However, the 3.5% reduction in fuel heat content in No. 1 fuel oil compared to No. 2 fuel oil is offset by the 3.1% reduction in price.

Therefore, DEC finds it cost effective for the NPPP to switch to combusting No. 1 fuel oil in EUs 1 and 2. This finding is predicated on the assumption that GVEA will be able to purchase No. 1 fuel oil from the Petro Star North Pole Refinery. If the North Pole Refinery is not able to

[4] National Emissions Inventory (NEI) | Air Emissions Inventories | US EPA

supply GVEA with No. 1 fuel oil due to shortages in supply, the NPPP may continue to burn No. 2 fuel oil in EUs 1 and 2 until such time as No. 1 fuel oil is again available.

e. Selection of SO_2 Controls for the Simple Cycle Gas Turbines

DEC's finding is that the control selected for this RH evaluation for SO_2 emissions from the fuel oil-fired simple cycle gas turbines is as follows:

SO_2 emissions from EUs 1 and 2 shall be controlled by limiting the sulfur content of fuel combusted in the turbines to no more than 0.1 percent by weight (1,000 ppmw, No. 1 fuel oil).[5]

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

2. Cost of Compliance for the Fuel Oil-Fired Combined Cycle Gas Turbine (EU 5)

The cost of compliance estimates the values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions that have been prepared according to EPA's Air Pollution Control Cost Manual. Costs are expressed in terms of cost effectiveness in the standardized unit of dollars per ton of actual SO_2 emissions reduced. DEC used information from the BACT analyses completed for the Fairbanks Serious SIP for SO_2 to complete the cost of compliance analyses. This information included previous BACT determinations found in the RBLC database, internet research, and BACT analyses submitted to DEC by GVEA for the NPPP and Zehnder Facility.

The RBLC was searched for all determinations in the last 10 years under the process code 15.290 for combined cycle gas turbines (rated at 25 MW or more) The search results for combined cycle gas turbines are summarized in Table III.K.13.F-16.

Table III.K.13.F-16. RBLC Summary of SO_2 Controls for Fuel Oil-Fired Combined Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits	
Ultra-Low Sulfur Diesel	1	0.0015	% S by wt.

a. RBLC Review

A review of similar units in the RBLC indicates that limiting the sulfur content of fuel is the principle SO_2 control technologies determined as BACT for fuel oil-fired combined cycle gas turbines. The lone SO_2 limit listed in the RBLC is for combustion of ULSD.

[5] In the event that the North Pole Refinery is not able to supply GVEA with No. 1 fuel oil due to shortages in supply, the North Pole Power Plant may continue to burn No. 2 fuel oil in EUs 1 and 2 until such time as No. 1 fuel oil is again available.

i. Identification of SO_2 Control Technology for the Fuel Oil-fired Combined Cycle Gas Turbines

From research, DEC identified the following technologies as available for control of SO_2 emissions from fuel oil-fired combined cycle gas turbines rated at 25 MW or greater:

1. Ultra Low Sulfur Diesel (ULSD)

The methods by which combusting ULSD reduces sulfur emissions was discussed in detail in Section 1.a.ii.1.a.ii - Identification of SO_2 Control Technology for the fuel oil-fired simple cycle turbines, and will not be repeated here. DEC considers ULSD a technically feasible control technology for the fuel oil-fired combined cycle gas turbines

2. Light Straight Run Turbine Fuel (LSR)

EU 5 typically combusts LSR when not in startup. The sulfur content of the LSR is limited to no more than 50 ppmv as required by Condition 5.1 of Minor Permit AQ0110MSS01. DEC considers operating LSR a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

b. Eliminate Technically Infeasible SO_2 Technologies for the Combined Cycle Gas Turbines

All control technologies identified are technically feasible for the fuel oil-fired combined cycle gas turbines.

c. Rank point the Remaining SO_2 Control Technologies for the Combined Cycle Gas Turbines

The following control technology has been identified and ranked for control of SO_2 from the fuel oil-fired combined cycle gas turbines (Table III.K.13.F-17):

Table III.K.13.F-17. Control Technology

Control Technology	Control Level
Ultra Low Sulfur Diesel	77.2% Control

Table Note: Control technologies already required at the stationary source, including burning LSR except during startup and practicing good combustion practices, or those included in the design of the EU are considered 0% control for the purposes of this four-factor analysis.

d. Evaluate the Most Effective Controls

GVEA provided an economic analysis for the Serious SIP BACT exercise for switching the fuel combusted in the combined cycle gas turbine to ULSD. DEC used this cost analysis and an update provided by GVEA for the cost per gallon of No. 1 fuel oil, ULSD and LSR delivered to the NPPP between January 2019 and October 2020 to perform our cost analysis.

i. Department Evaluation of BACT for SO_2 Emissions from the Combined Cycle Gas Turbines

DECs cost analysis calculated a cost per ton of SO_2 emissions removed resulting from a switch to ULSD. There is no capital cost involved with this fuel switch for EU 5. Therefore, the only value driving cost for the evaluation was the yearly cost difference in fuel prices between LSR and No. 1 (used during start-up) compared to ULSD.

A summary of these analyses is shown in Table III.K.13.F-18.

Table III.K.13.F-18. Department Economic Analysis for Technically Feasible SO_2 Controls for EU 5

Control Alternative	2016 SO_2 Emissions (tons)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	10.75	8.30	N/A	$12,802,923	$1,542,463
Capital Recovery Factor = 0.0 (There is no capital investment involved with this cost calculation)					

DEC's cost of compliance economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD for the fuel oil-fired combined cycle gas turbine at the NPPP ($1,542,463/ton). Therefore, there is no emission limit or control selected for EU 5 as a part of the RH economic analysis. DEC notes that this analysis was based on actual emissions and therefore only EU 5 was evaluated. However, the Permittee is authorized to install an identical fuel oil-fired combined cycle gas turbine (EU 6) under prior air quality permitting. Therefore, this evaluation for EU 5 is also considered an evaluation for EU 6 upon installation.

3. Time Necessary for Compliance

DEC chose to require GVEA to make a switch to fuel oil with a maximum sulfur content of 0.1 percent by weight (1,000 ppmw, No. 1 fuel oil) for EUs 1 and 2. GVEA shall submit a permit application by January 1, 2024, to make this fuel switch enforceable and the requirement to combust No. 1 fuel oil will be effective January 1, 2025.

4. Energy and Non-Air Quality Environmental Impacts

No. 1 fuel oil contains slightly less fuel heat content at 133.4 MMBtu/kgal compared to No. 2 fuel oil at 138.3 MMBtu/kgal as reported by GVEA in the 2019 NEIs. This results in approximately a 3.5% reduction in fuel heat content compared to No. 2 fuel oil. Therefore, the stationary source will have to combust slightly more fuel to make the same power output. However, this slight increase in fuel consumption will be offset by the approximately 68% reduction in SO_2 emissions resulting from combusting the lower sulfur fuel oil.

5. *Remaining Useful Life of the Source*

At this time, DEC anticipates the NPPP will be operating indefinitely. DEC continues to track changes at point sources through its Title I and Title V permitting programs and is considering whether to include requirements to maintain operating and maintenance schedules on site, that could be included in operating permit renewals. This would include maintaining an anticipated equipment replacement schedule and potentially dates for expected source retirement.

DEC Regional Haze Findings for GVEA's North Pole Power Plant

Finding: DEC finds that it is cost effective and feasible for GVEA to switch EUs 1 and 2 to fuel oil with a maximum sulfur content of 0.1 percent by weight (1,000 ppmw, No. 1 fuel oil). This finding is predicated on the assumption that GVEA will be able to purchase No. 1 fuel oil from the Petro Star North Pole Refinery. If the North Pole Refinery is not able to supply GVEA with No. 1 fuel oil due to shortages in supply, the NPPP may continue to burn No. 2 fuel oil in EUs 1 and 2 until such time as No. 1 fuel oil is again available.

On or before January 1, 2024, GVEA shall submit a Title I permit application to DEC that includes a RH requirement to limit the sulfur content of fuel combusted in EUs 1 and 2 to fuel oil with a maximum sulfur content of 0.1 percent by weight (1,000 ppmw, No. 1 fuel oil) to be effective no later than January 1, 2025. A summary of DEC's findings is as follows:

Table III.K.13.F-19. Final Determination for GVEA – North Pole Power Plant

Pollutant	Regional Haze Controls	Regional Haze Determination	Effective Dates of Control/Limit
EUs 1 and 2 – Fuel Oil-Fired Simple Cycle Gas Turbines - 672 MMBtu/hr (each)			
SO_2	Clean Fuel Switch to No. 1 fuel oil	Switch to fuel oil with a maximum sulfur content of 0.1 percent by weight (1,000 ppmw, No. 1 Fuel Oil)*	Submit permit application by January 1, 2024 Expect permit issuance by January 1, 2025
EUs 5 and 6 – Combined Cycle Gas Turbines - 455 MMBtu/hr (each)			
SO_2	Already Effectively Controlled (50 ppmw sulfur limit in fuel except during startup)	No Additional Control	N/A

* This finding is predicated on the assumption that GVEA will be able to purchase No. 1 fuel oil from the Petro Star North Pole Refinery. If the North Pole Refinery is not able to supply GVEA with No. 1 fuel oil due to shortages in supply, the NPPP may continue to burn No. 2 fuel oil in EUs 1 and 2 until such time as No. 1 fuel oil is again available.

b. Golden Valley Electric Association: Healy Power Plant

The Healy Power Plant is an electric generating facility owned and operated by GVEA, and GVEA is the Permittee for the stationary source's Title V Operating Permit AQ0173TVP03. The SIC code for this stationary source is 4911 – Electrical Power Generation. The primary power generating units include two coal-fired steam generators: the 25-MW Foster-Wheeler Unit No. 1 (EU 1) and the 54-MW TRW Integrated Entrained Combustion System (EU 2) formerly known as the Healy Clean Coal Project (HCCP). The stationary source also operates two Cleaver

Brooks standby building boilers (EUs 3 and 4), one standby diesel generator (EU 5), and a firewater pump engine (EU 13). These emissions units (EUs) are listed below in Table III.K.13.F-20.

Table III.K.13.F-20. Healy Power Plant Emission Unit Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Construction Date
1	Unit No. 1	Foster-Wheeler Boiler, pulverized coal fired steam generator with a 12 module ICA baghouse, SN 78-266	327 MMBtu/hr	November 1967
2	Unit No. 2	TRW Integrated Entrained Combustion System, pulverized coal-fired steam generator with Joy activated recycle spray dryer absorber and Joy pulse jet fabric filter, SN 1	658 MMBtu/hr	1996
3	Auxiliary Boiler No. 1	Cleaver Brooks CB 189-300, Standby process and building boiler, SN L-39759, Diesel-fired	12.554 MMBtu/hr	1967
4	Auxiliary Boiler No. 2	Cleaver Brooks CB 100-800-15, Standby process and building boiler, SN OLO94777, Diesel-fired	23.0 MMBtu/hr	1996
5	Diesel Generator No. 1	Electro-Motive Diesel, EMD 20-645-E4, SN 67-B1-1152 (engine) Standby diesel generator, SN A-20-D (generator)	2.75 MW	1967
6	Crusher System	Crusher System2 SN 885247 (Secondary Crusher No. 1) SN 844034 (Secondary Crusher No. 2)	12,000 cfm	1996
73	Limestone Storage Silo	Limestone Storage Silo with baghouse	800 cfm	1996
8	Flyash Storage Silo	Flyash Storage Silo with baghouse	5,000 cfm	1996
9	Sodium Bicarbonate Handling System	Sodium bicarbonate handling system4	440 cfm	1998
10	Coal Handling System (dust collector #2)	Coal Handling System5	20,000 cfm	1996

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Construction Date
13	Firewater Pump Engine	Caterpillar Diesel Model 3406B, Diesel-fired firewater pump engine; SN 6TB14931	264 hp	1997
Fugitive Emission Sources				
11	Haul Road	Haul Road (located on GVEA property) from Usibelli Coal Mine property line to coal pile	0.25 miles	1967
12	Coal Storage Pile	Open Coal Storage Piles	Up to 15-day coal supply, with both EU IDs 1 and 2 in operation	1967

For the second implementation period RH SIP update, DEC performed a limited review in place of a full four-factor analysis because the stationary source already has dry sorbent injection (DSI) emissions controls installed on EU 1 and has spray dry absorber (SDA) emissions controls installed on EU 2. Additionally, GVEA is under a Consent Decree (CD) with the EPA which requires GVEA to decide on or before December 31, 2022, to either install SCR (or an alternative NO_x control technology approved by EPA) on EU 1 or retire the boiler. The deadline to have SCR installed on EU 1 or have the EU retired is no later than December 31, 2024. DEC looked back over the previous six-year period (2014-2019) for which data is currently available to determine the source's SO_2 emissions. Table III.K.13.F-21 shows SO_2 emissions reported to DEC through the NEI for 2014 and 2016 through 2019 (the years that NEI information was available for the source) and used the emissions fee estimate for 2015.

Table III.K.13.F-21. Healy Power Plant SO_2 Emissions

Calendar Year	Coal-Fired Boilers SO_2 Emitted (tons)	Other EUs SO_2 Emitted (tons)	Total SO_2 Emitted (tons)
2019	318.09	0.00	318.09
2018	376.02	0.00	376.02
2017	296.40	0.00	296.40
2016	427.20	0.00	427.20
2015	689.00	0.00	689.00
2014	444.94	0.00	444.94

As can be seen from Table III.K.13.F-21, the SO_2 emissions emitted at the Healy Power Plant are from the two coal-fired boilers EUs 1 and 2, which DEC focused on. Condition 44 of Operating Permit AQ0173TVP03 limits EU 2 to a SO_2 emissions rate of not more than 0.10 lb/MMBtu, and Condition 44.1 requires EU 2 to use SDA when in operation. Condition 45 of Operating Permit AQ0173TVP03 limits EU 1 to a SO_2 emissions rate of not more than 0.30 lb/MMBtu, and Condition 45.1 requires EU 1 to use DSI when in operation. Section II.B.3.f. of the Guidance

Document discusses selecting sources that already have effective emission control technology in place. The Guidance Document states the following:

> "It may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous RH SIP or to meet another CAA requirement. In general, if post-combustion controls were selected and installed recently (see illustrative examples below) to meet a CAA requirement, there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions having been made in the intervening period. If a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period. A state that does not select a source or sources for the following or any similar reasons should explain why the decision is consistent with the requirement to make reasonable progress, i.e., why it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary."

In addition, Section II.B.3.f. of the Guidance Document also goes on to state:

> "BART-eligible units that installed and began operating controls to meet BART emission limits for the first implementation period, on a pollutant-specific basis. Although the Regional Haze Rule anticipates the re-assessment of BART-eligible sources under the reasonable progress Rule provisions, if a source installed and is currently operating controls to meet BART emission limits, it may be unlikely that there will be further available reasonable controls for such sources. However, states may not categorically exclude all BART-eligible sources, or all sources that installed BART controls, as candidates for selection for analysis of control measures."

Section II.B.3.d. of the Guidance Document discusses the option to consider the four statutory factors when selecting sources and states the following:

> "EPA expects that, typically, states are more likely to select sources based on visibility impacts and not consider the four reasonable progress factors (i.e., cost of compliance, remaining useful life, time necessary for compliance, and energy and non-air quality environmental impacts) until after a source is selected. However, in some cases, a state may already have information on one or more of the four reasonable progress factors at the time of source selection. If so, the state may consider that information at the source-selection stage. In particular circumstances, that information may indicate that it is reasonable to exclude the source for evaluation of emission control measures because it is clear at this step that no additional control measures would be adopted for the source. The source-selection step is intended to add flexibility and discretion to the state planning process – ultimately, the state decides which sources to consider for reasonable progress."

DEC has chosen not to perform a full four-factor analysis on the Healy Power Plant because the two coal-fired boilers already have SO_2 emissions controls. Additionally, EU 1 may be retired in the near future and already went through a BART analysis during the first implementation period RH SIP that found additional SO_2 controls on the EU to be cost ineffective. In the case of EU 2, the coal-fired boiler has an emissions limit of 0.10 lb/MMBtu with SDA, which is half the emissions limit given in the Guidance Document's example of a coal-fired boiler electrical generating unit that is equipped with flue gas desulfurization (which includes DSI and SDA) that meets a 0.2 lb/MMBtu emission rate. Although EU 1 has a less stringent emissions limit of 0.30 lb/MMBtu, the boiler is equipped with DSI using sodium bicarbonate, which the EPA Air Pollution Control Cost Manual estimates can achieve control efficiencies of 50 to 70%.[6] The emissions data reported via the NEI from the continuous emissions monitoring system for EU 1 over the previous three-year period for which data is available (2017-2019) showed an average SO_2 emissions rate of 0.26 lb/MMBtu. Additionally, the CD requires GVEA to decide on or before December 31, 2022, to either install SCR (or an alternative control technology approved by EPA) on EU 1 or retire the boiler. As of September 30, 2021, GVEA has yet to decide on adding additional controls or retiring the EU.

The 2010 Regional Haze BART determination[7] for Healy EU 1 found that the incremental cost effectiveness for the addition of a spray dry absorber system was $29,813 per ton of SO_2 removed and for a wet scrubber system was $12,033 per ton of SO_2 removed. In line with the Guidance Document, DEC believes that there has been no significant cost reductions in the previous decade that would warrant re-evaluating the addition of these two types of controls for EU 1 as they would still be considered cost ineffective. However, the previous BART determination found that optimizing the already installed DSI system on EU 1 would cost $4,218 per ton of SO_2 removed. It is possible that a re-evaluation of DSI optimization for EU 1 could result in a cost effectiveness finding by DEC. Therefore, in the event that GVEA chooses not to retire EU 1, DEC will require that GVEA complete a full four-factor analysis for DSI optimization and submit the final four factor analysis to DEC by July 1, 2023. Alternatively, GVEA may establish an enforceable emission limit for SO_2 of 0.20 lb/MMBtu by submitting an application for a permit amendment by January 1, 2024. It would be expected that a permit would be issued by January 1, 2025, which would result in EU 1 being considered an effectively controlled EU per the Guidance Document.

Final Determination for GVEA Healy Power Plant

The conclusion of DEC's limited review for GVEA's Healy Power Plant is that EU 2 is effectively controlled, and the stationary source is in the process of deciding to retire the older coal-fired boiler EU 1 or add on SCR controls. EU 1 has the highest SO_2 emissions per MMBtu of energy consumed in all GVEA's emissions unit inventory, and the Healy Power Plant is their closest stationary source to a Class I area (Denali). Therefore, if GVEA decides to retire EU 1 this would result in a shift of electricity generation to other EUs owned by GVEA's fleet of emissions units, which would result in a net reduction of SO_2 emissions. If GVEA elects not to retire EU 1, there will be a reduction in NO_x emissions as SCR would be installed which should have a positive impact on visibility. Additionally, DEC will require GVEA to complete a full four-factor analysis for DSI optimization and submit the final four factor analysis to DEC by

[6] EPA Air Pollution Control Cost Manual Section 5 SO_2 and Acid Gas Controls Chapter 1.2.1.3: https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0341-0082.

[7] See the Appendix III.K.6 Best Available Retrofit Technology (BART) Documentation PDF on DEC's website: https://dec.alaska.gov/air/anpms/regional-haze/sip/.

July 1, 2023, or establish an enforceable emission limit for SO_2 of 0.20 lb/MMBtu by submitting an application for a permit amendment by January 1, 2024. It would be expected that a permit would be issued by January 1, 2025, which would result in EU 1 being considered effectively controlled EU per the Guidance Document. DEC will continue to monitor the status of GVEA's decision with respects to their CD with the EPA. A summary of DEC's RH findings are as follows:

Table III.K.13.F-22. Final Determination for GVEA – Healy Power Plant

Pollutant	Regional Haze Controls	Regional Haze Determination	Effective Dates of Control/Limit
EU 1 – Coal-Fired Boiler with DSI - 327 MMBtu/hr			
SO_2	Option 1 – Consent Decree	Retire EU 1 by December 31, 2024	Decision by December 31, 2022 Retirement effective no later than December 31, 2024
	Option 2 – Four Factor Analysis	Submit a four-factor analysis for DSI optimization to DEC	Submit Four-Factor Analysis by July 1, 2023
	Option 3 – Enforceable Limit	Establish enforceable emission limit of 0.20 lb/MMBtu	Submit permit application by January 1, 2024 Expect permit issuance by January 1, 2025
EU 2 – Coal-Fired Boiler with SDA - 658 MMBtu/hr			
SO_2	Already Effectively Controlled (0.10 lb/MMBtu emission rate with Spray Dry Absorber)	No Additional Controls	N/A

c. Aurora Energy, LLC: Chena Power Plant

The Chena Power Plant is an electric generating facility owned and operated by Aurora Energy, LLC (Aurora), and Aurora is the permittee for the stationary source's Title V Operating Permit AQ0315TVP04 Revision 1. The SIC code for this stationary source is 4911 - Electric Services. The Chena Power Plant is a co-generation power plant that is designed to supply the local power grid with up to 27.5 megawatts of electrical power and provide steam and hot water heat to commercial and residential customers in the city of Fairbanks. The power producing units consist of four coal-fired boilers. These EUs are listed below in Table III.K.13.F-23 and Table III.K.13.F-24.

Table III.K.13.F-23. Chena Power Plant Emission Unit Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Installation or Construction Date
1	Coal Preparation Plant	Exhaust and Fugitive Emissions	75 tons/hour	1950[1]
2	Coal Stockpile	Fugitive Emissions	0.59 acre	1950[2]
3	Ash Vacuum Pump Exhaust	Ash System Baghouse Exhaust	24,187 tons/yr (of ash)	1997
4	Chena 1 Coal-Fired Boiler	Full Stream Baghouse Exhaust	76.8 MMBtu/hr	1952
5	Chena 2 Coal-Fired Boiler	Full Stream Baghouse Exhaust	76.8 MMBtu/hr	1952
6	Chena 3 Coal-Fired Boiler	Full Stream Baghouse Exhaust	76.8 MMBtu/hr	1954
7	Chena 5 Coal-Fired Boiler	Full Stream Baghouse Exhaust	254.7 MMBtu/hr	1970

Table Notes: [1] EU ID 1 was modified in 1990.
[2] EU ID 2 was modified in 2013.

Table III.K.13.F-24. Chena Power Plant Fugitive Emission Unit Inventory

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Installation or Construction Date
8	Truck Bay Ash Loadout	Bottom of silo – Fugitive Emissions	N/A	1952
9	Paved Roadways	Fugitive Emissions	N/A	1950

The Chena Power Plant recently went through an emissions control analysis as a part of the designation of the FNSB nonattainment area as "Serious" with regard to nonattainment of the 2006 24-hour $PM_{2.5}$ NAAQS which was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706. CAA section 189(b)(1)(B) and 40 C.F.R. § 51.1010 describe the Serious area attainment plan requirements for BACM/BACT. Large stationary sources are a subgroup of emissions sources that are given special attention in the required BACM/BACT analysis. Per federal requirement, DEC evaluated all point sources with emissions greater than 70 TPY of $PM_{2.5}$ or for any individual $PM_{2.5}$ precursor (NO_x, SO_2, NH_3, VOCs). This evaluation resulted in the following emissions controls contained in Table III.K.13.F-25, which are those required in Table 7.7-10 of the Amendments to: State Air Quality Control Plan Vol II: III.D.7.7 Control Strategies document; adopted November 19, 2019.[3]

Table III.K.13.F-25. BACT and SIP Findings Summary Table for Chena Power Plant

Pollutant	BACT Emission Limit	BACT Control Device or Operational Limitation	Effective Dates of Control/Limit
EUs 4 through 7 - Coal-Fired Boilers - 497 MMBtu/hr (combined)			
NO_x	Precursor Demonstration*	No additional control	N/A
SO_2	0.25% sulfur by weight	Certified Statement of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
	0.301 lb/MMBtu (3-hr avg.)	No Additional Controls (periodic source testing)	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021

Section II.B.3.f. of the Guidance Document discusses selecting sources that have recently undergone emission control technology review. The Guidance Document states the following:

> "New, reconstructed, or modified emission units that went through Best Available Control Technology (BACT) review under the Prevention of Significant Deterioration (PSD) program or Lowest Achievable Emission Rate (LAER) review under the nonattainment new source review program for major sources and received a construction permit on or after July 31, 2013,46 on a pollutant-specific basis. The statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress."

DEC Regional Haze Findings for Chena Power Plant

DEC's recent analysis of the Chena Power Plant for the Serious nonattainment area resulted in a limit on the sulfur content of the coal received at the stationary source as well as an SO_2 limit on the coal-fired boilers themselves. Taking into consideration the BACT analysis recently performed for the nonattainment area and the sulfur limits already imposed by this effort, DEC will not further evaluate the Chena Power Plant for the second implementation period of RH planning. A summary of DEC's RH findings are as follows:

Table III.K.13.F-26. Final Determination for Chena Power Plant

Pollutant	Regional Haze Controls	Regional Haze Determination	Effective Dates of Control/Limit
EUs 4 through 7 - Coal-Fired Boilers - 497 MMBtu/hr (combined)			
SO_2	Already Effectively Controlled (0.301 lb/MMBtu; 0.25% sulfur be weight in coal)*	No Additional Controls	N/A

* Background and detailed information regarding Fairbanks $PM_{2.5}$ State Implementation Plan (SIP) can be found at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/.

d. US Air Force: Eielson Air Force Base

The Eielson Air Force Base (Eielson AFB) is owned and operated by the United States Air Force (USAF), and the USAF is the permittee for the stationary source's Title V Operating Permit AQ0264TVP02 Revision 5. The SIC code for this stationary source is 9711 – National Security. Eielson AFB consists of an operational airfield, residential housing, office buildings, gas stations, utilities, military police and fire departments, public schools, chapels, hospital facilities, retail stores, recreational facilities, and more. The stationary source's EUs are listed below in Table III.K.13.F-27.

Table III.K.13.F-27. Eielson Air Force Base Emission Unit Inventory

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Install Date
Coal Fired Boilers1				
1	CH&PP Main Boiler #1	Springfield Boiler	120,000 lb/hr	1952
2	CH&PP Main Boiler #2	Springfield Boiler	120,000 lb/hr	1952
3	CH&PP Main Boiler #3	Springfield Boiler	120,000 lb/hr	1952
4	CH&PP Main Boiler #4	Springfield Boiler	120,000 lb/hr	1952
5A	CH&PP Main Replacement Boiler #5	Coal-Fired Boiler	120,000 lb/hr	2016
6A	CH&PP Main Replacement Boiler #6	Coal-Fired Boiler	120,000 lb/hr	2014
Liquid Fuel Fired Boilers				
7	Auxiliary Heating Plant Boiler #1	Cleaver Brooks Boiler	58.7 MMBtu/hr	2002
8	Auxiliary Heating Plant Boiler #2	Cleaver Brooks Boiler	58.7 MMBtu/hr	2002
9	Missile Storage Boiler #1	Cleaver Brooks Boiler	3.3 MMBtu/hr	1991
10	Missile Storage Boiler #2	Cleaver Brooks Boiler	2.9 MMBtu/hr	1993
11	Alert Hangar Boiler #1	Cleaver Brooks Boiler	6.0 MMBtu/hr	2008
12	Alert Hangar Boiler #2	Cleaver Brooks Boiler	6.0 MMBtu/hr	2008
13	Waste Water Treatment Boiler #12	Cleaver Brooks Boiler	6.7 MMBtu/hr	2012
14	Waste Water Treatment Boiler #2	Cleaver Brooks Boiler	6.7 MMBtu/hr	2012
15	Auxiliary Heating Plant II Boiler #1	--TBD; Not Installed--	98 MMBtu/hr	TBD

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Install Date
16	Auxiliary Heating Plant II Boiler #2	--TBD; Not Installed--	98 MMBtu/hr	TBD
Propane Fired Heaters				
17	Corrosion Control Heater #1	Midco Burner	17.0 MMBtu/hr	1987
18	Corrosion Control Heater #2	Midco Burner	17.0 MMBtu/hr	1987
Diesel and Gasoline Fired Internal Combustion Engines				
19	CH&PP Main Auxiliary Generator	EMD Diesel Engine	2,500 kW	1987
20	CH&PP Auxiliary Power Generator #1	Onan Diesel Engine	1,125 kW	1998
21	CH&PP Auxiliary Power Generator #2	Onan Diesel Engine	1,125 kW	1998
22	CH&PP Auxiliary Power Generator #3	Onan Diesel Engine	1,125 kW	1998
23	CH&PP Auxiliary Power Generator #4	Onan Diesel Engine	1,125 kW	1998
24	Waste Water Treatment Generator	Caterpillar Diesel Engine	500 kW	1994
25	Central Avenue (Clinic) Generator	Cummins Diesel Engine	300 kW	2006
26	Refueling Station Generator-Oscar Row	Onan Diesel Engine	750 kW	1994
27	Engineer Hill Generator	Onan Diesel Engine	150 kW	1987
28	Alert Hangar Generator	Komatsu Diesel Engine	100 kW	1985
29	Power Plant Fire Pump	Caterpillar Diesel Engine	196 hp	1987
30	Missile Maintenance Generator	Onan-Cummins Diesel Engine	125 kW	2011
31	Control Tower Generator	Onan Diesel Engine	125 kW	2005
32	Telephone Exchange Generator	Cummins Diesel Engine	125 kW	2003
33	Command Post Generator	Cummins Diesel Engine	80 kW	2009
34	Airfield Lighting Generator	Onan Diesel Engine	300 kW	2003
35	Fire Pump P8 (Thunder Dome #1)	Cummins Diesel Engine	340 hp	1989
36	Fire Pump P9 (Thunder Dome #2)	Cummins Diesel Engine	340 hp	1989
37	Fire Pump P10 (Thunder Dome #3)	Cummins Diesel Engine	340 hp	1989
38	Fire Pump P11 (F-16 Hangar Pump #1)	Cummins Diesel Engine	340 hp	1986
39	Fire Pump P12 (F-16 Hangar Pump #2)	Cummins Diesel Engine	340 hp	1986

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Install Date
40	Fire Pump P13 (F-16 Hangar Pump #3)	Cummins Diesel Engine	340 hp	1986
41	Fire Pump P19 (Hog Pen A-10s)	Detroit Diesel Engine	235 hp	1994
42	Fire Pump P20 (Hog Pen A-10s)	Detroit Diesel Engine	235 hp	1994
43	Fire Pump P6 – Fire Support	Caterpillar Diesel Engine	121 hp	1989
44	Fire Pump P5 – Fire Support	Caterpillar Diesel Engine	121 hp	1990
45	Fire Pump P1 – Fire Support	Caterpillar Diesel Engine	121 hp	1989
46	Taxi Way #3 Fire Pump	Caterpillar Diesel Engine	121 hp	1989
47	Pumphouse #3 Fire Pump	Caterpillar Diesel Engine	121 hp	1989
48	Fire Pump P2	Caterpillar Diesel Engine	120 hp	1989
49	Communications Squadron Emergency Generator	Onan Diesel Engine	100 kW	2003
50	Water Treatment Plant Generator	Cummins Diesel Engine	300 kW	2012
51	Utilidor (Auxiliary Heat Plant) Emergency Generator	Onan Diesel Engine	500 kW	2002
52	E-2 Complex Fuel Tank Emergency Generator	Kohler Power Diesel Engine	475 kW	2002
53	Fuel Hydrant System Emergency Generator	Caterpillar Diesel Engine	556 kW	2002
54	Joint Mobility Complex (JMC) Emergency Generator	Cummins Diesel Engine	800 kW	2002
55	North ILS Generator	Onan Diesel Engine	60 kW	1993
56	DET 460 Generator	Cummins Diesel Engine	60 kW	2010
57	Conventional Munitions Fire Pump #1	Detroit Diesel Engine	120 hp	1999
58	Conventional Munitions Fire Pump #2	Detroit Diesel Engine	120 hp	1999
59	New Security Forces Facility Generator (CSC)	Cummins Diesel Engine	350 kW	2005
60	Fire Stationary No. 1 Generator	Cummins Diesel Engine	80 kW	2003
61	Base Supply Fire Pump	Cummins Diesel Engine	208 hp	1993
62	354 Wing MOC Generator	Cummins Diesel Engine	100 kW	2004
63	F-Well pump	Cummins Diesel Engine	230 hp	2010
65	Aircraft Arrestor Engine NW3	Waukesha Gas Engine	65 hp	1970
66	Aircraft Arrestor Engine NE	Waukesha Gas Engine	65 hp	1970
67	Aircraft Arrestor Engine ¾ W	Waukesha Gas Engine	65 hp	1970
68	Aircraft Arrestor Engine ¾ E	Waukesha Gas Engine	65 hp	1970
69	Aircraft Arrestor Engine SE	Waukesha Gas Engine	65 hp	1970
70	Aircraft Arrestor Engine SW	Waukesha Gas Engine	65 hp	1970

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Install Date
71	Loop Refueling (Type III Hydrant) Generator	Cummins Diesel Engine Emergency Generator	450 kW	2006
73	4 Bay Loop Hangar	Cummins Diesel Engine	100 kW	2010
74	8 Bay Loop Hangar	Cummins Diesel Engine	200 kW	2010
75	Missile Maintenance Well Pump Generator	Cummins Diesel Engine	60 kW	2006
76	E-2 Farm Fire Pump Emergency Generator	Deere Diesel Engine	120 hp	2005
77	Dining Facility Emergency Generator	Cummins Diesel Engine	230 kW	2010
78	Red Flag Emergency Generator	Cummins Diesel Engine	50 kW	2009
80	Cooling Pond Generator	Cummins Diesel Engine	350 kW	2010
Hush House (Jet Engine Test Facility)				
81	Hush House	N/A	N/A	1989
Portable Asphalt/Rock Crusher Diesel Fired Internal Combustion Engines				
82	Recycle Plant Engine	John Deere Diesel Engine	450 hp	2007
83	Jaw Crusher Engine	John Deere Diesel Engine	450 hp	2008
84	Hydrascreen Engine	Deutz Diesel Engine	96 hp	2007
Fire Training				
85	Fire Training	Fire Training Burn	N/A	N/A
Portable Asphalt/Rock Crusher Fugitives				
86	Crusher #1	Cobra 1000 Recycling Plant	150 TPH	2007
87	Conveyor Transfer Point #1	Transfer Point (Recycling Plant to Superior Stackable Conveyor)	150 TPH	2007
88	Conveyor Transfer Point #2	Transfer Point (Superior Stackable conveyor to 683 Hydrascreen	150 TPH	2007
89	Screening	Findlay 683 Hydrascreen	150 TPH	2007
90	Conveyor Transfer Point #3	Transfer Point (683 Hydrascreen to Oversize Return Conveyor Belt)	50 TPH	2007
91	Conveyor Transfer Point #4	Transfer Point (Oversize Conveyor Belt Return to Cobra 1000 Recycle Plant)	50 TPH	2007
92	Conveyor Transfer Point #5	Transfer Point (683 Hydrascreen to Second Deck Oversize Return Conveyor Belt)	50 TPH	2007
93	Fines Screening	683 Hydrascreen Fines Screen	100 TPH	2007
94	Conveyor Transfer Point #6	Transfer Point (Fines Screen to Fines Belt)	100 TPH	2007

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Install Date
95	Conveyor Transfer Point #7	Transfer Point (Fines Belt to Superior Radial Stacking Conveyor)	100 TPH	2007
96	Conveyor Transfer Point #8	Transfer Point (Conveyor Discharge onto Asphalt Pile)	100 TPH	2007
97	Jaw Crusher Feed	Jaw Crusher Dump Point	150 TPH	2008
98	Conveyer Transfer Point #9	Transfer Point (Jaw Crusher Screen to Superior Conveyer # 1)	100 TPH	2008
99	Conveyer Transfer Point #10	Transfer Point (Superior Conveyer # 1 to Superior Conveyer # 2)	100 TPH	2008
100	Conveyer Transfer Point #11	Transfer Point (Superior Conveyer # 2 discharge on to Asphalt Stockpile)	100 TPH	2008
101	Crusher #2	Jaw Crusher	150 TPH	2008
102	Conveyer Transfer Point #12	Transfer Point (Jaw Crusher Conveyer to Recycling Plant Feed Conveyor)	150 TPH	2008
103	Conveyer Transfer Point #13	Transfer Point (Jaw Crusher Conveyer to Cobra 1000 Recycling Plant)	150 TPH	2008
Jet Kerosene (JP-8) Storage Tanks				
104	South Ramp Loop Tank #6167	AST – Internal Floating Roof Tank	420,000 gal	2006
105	South Ramp Loop Tank #6268	AST – Internal Floating Roof Tank	420,000 gal	2006
106	Tanker Row Tank #3241-5	AST – Internal Floating Roof Tank	420,000 gal	2000
107	Tanker Row Tank #3244-6	AST – Internal Floating Roof Tank	420,000 gal	2000
Other Regulated Sources				
109	Aircraft Corrosion Control Facility	Regulated Surface Coating	N/A	1987
110	Sandwich Belt Conveyer	Regulated Coal Processing System	N/A	1994
111	Coal Tripper System	Coal Tripper system with 6 identical 2,500 cfm Pulse Jet Collector Bin Vent Filters	150 TPH	2010
Insignificant CI RICE Subject to NESHAP Subpart ZZZZ				
64A	A Water Well Pump Generator5	Cummins Diesel Engine	60 kW	2012
64B	B Water Well Pump Generator	Cummins Diesel Engine	60 kW	2012
112	North Glideslope Generator	Cummins Diesel Engine	23 kW	2001

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Install Date
113	ASOS/GPS Generator	Onan Diesel Engine	30 kW	2005
114	Base Radio MARS Generator	Onan Diesel Engine	35 kW	2003
115	TACAN South Glideslope Generator	Onan Diesel Engine	35 kW	2005
116	Lift Station Generator	Cummins Diesel Engine	30 kW	1991
117	South ILS Generator	Onan Diesel Engine	35 kW	2005
118	Quarry Hill Generator	Deere Diesel Engine	26 kW	2004
119	POL Control Generator	Kubota Diesel Engine	20 kW	2010
120	Consolidated Munitions Generator	Onan Diesel Engine	16 kW	1999
121	CE Control Generator	Onan Diesel Engine	6 kW	1985
122	Fire Station #2 Generator	John Deere Diesel Engine	55 kW	1997
123	Emergency Wastewater Pump Engine	John Deere 4039D Diesel Engine	60 kW	1991
124	Emergency Wastewater Pump Engine	John Deere 4045D Diesel Engine	63 kW	2008
125	Emergency Wastewater Pump Engine	John Deere 4045D Diesel Engine	63kW	2008
129	North Slope Relay Generator	Cummins Diesel Engine	60 kW	2011
Insignificant Gasoline Storage Tanks Subject to NESHAP Subpart CCCCCC				
126	Horizontal Gasoline Fuel Tank	N/A	25,948 gallons	1987
127	Horizontal Gasoline Fuel Tank	N/A	25,948 gallons	1987
128	Horizontal Gasoline Fuel Tank	N/A	25,948 gallons	1987

Table Notes: Minor Permit AQ0264MSS05 was issued on August 9, 2010, and authorizes the stationary source to replace the existing coal-fired boilers EUs 1 through 6 with new coal-fired boilers EUs 1A, 2A, and 4A through 6A.

For the second implementation period RH SIP update, DEC performed a limited review in place of a full four-factor analysis because the stationary source is already in the process of installing DSI using sodium bicarbonate on the replacement coal-fired boilers EUs 1A, 2A, and 4A through 6A as the older coal-fired boilers EUs 1 through 6 are being phased out. Currently EUs 5A, and 6A have already been installed at the stationary source with sodium bicarbonate DSI controls. DEC looked back over the previous six-year period (2014-2019) for which data is currently available to determine the sources SO_2 emissions. Table III.K.13.F-28 shows SO_2 emissions reported to DEC in emission fee estimates from 2014 through 2019. Additionally, the SO_2 emissions reported in the NEI for 2014 and 2017 (the only year that NEI information was available for the source) are contained in Table III.K.13.F-28 as a footnote.

Table III.K.13.F-28. Eielson Air Force Base SO_2 Emissions

Calendar Year	Coal-Fired Boilers SO_2 Emitted (tons)	Other EUs SO_2 Emitted (tons)	Total SO_2 Emitted (tons)
2019	237.98	3.66	241.64
2018	211.77	3.20	214.97
2017	238.90	1.70	240.60[1]
2016	261.18	1.54	262.72
2015	263.10	2.30	265.40
2014	267.3	1.70	269.00[1]

Table Notes: [1] USAF reported 262.81 tons of SO_2 emissions in the 2017 NEI and 268.05 tons of SO_2 emissions in the 2014 NEI.

As can be seen from Table III.K.13.F-28, the sizeable SO_2 emissions emitted at the Eielson AFB are from the coal-fired boilers. DEC created Table III.K.13.F-29 below to differentiate the SO_2 emissions from the older coal-fired boilers EUs 1 – 4, as well as the newly installed coal-fired boilers with DSI, EUs 5A and 6A. Note that Table III.K.13.F-29 starts in 2017 as this is the first full year of operating both boiler EUs 5A and 6A.

Table III.K.13.F-29. Eielson Air Force Base SO_2 Emissions

Year	EU ID	Coal Usage (tpy)	Coal Usage Percent of Total	SO_2 E.F. (lb/ton)	SO_2 E.F. % reduction From EUs 1-4	SO_2 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

As can be seen from Table III.K.13.F-29 above, the newer coal fired boilers EUs 5A and 6A equipped with DSI controls emit approximately 80% fewer SO_2 emissions per ton of coal combusted, compared to EUs 1 through 4.

The USAF received authorization to do a phased replacement of the coal boilers with the issuance of Minor Permit AQ0264MSS05 on August 9, 2010. The permit application for this project anticipated that Eielson AFB would have the final boiler (EU 1A) installed in October 2019 and EU 3 demolished in 2020. However, the timeline for the replacement of the boilers has stalled with EU 6A starting up on October 28, 2014, and EU 5A starting up on October 10, 2016, and no significant progress towards boiler replacement has taken place since that date. Therefore, DEC will require the USAF to either submit an application for a permit amendment to establish an enforceable retirement date for the remaining coal-fired boilers EUs 1 through 4 or submit a full four-factor analysis for add on SO_2 pollution control technologies to include wet scrubbers, DSI, and SDA by July 1, 2023.

DEC Regional Haze Findings for Eielson Air Force Base

The conclusion of DEC's limited review for USAF's Eielson AFB is that the stationary source is still intending to replace the older coal-fired boilers without SO_2 emissions controls with newer coal-fired boilers with sodium bicarbonate DSI and SCR. The two boilers already replaced are averaging about 80% less SO_2 emissions per ton of coal consumed compared to the older boilers. In the years to come, as the older boilers are replaced, there will be a substantial decline in emissions from the stationary source which will result in a positive impact on visibility. DEC will require the USAF to either submit an application for a permit amendment to establish an enforceable retirement date for the remaining coal-fired boilers EUs 1 through 4 or submit a full four-factor analysis for add on SO_2 pollution control technologies to include wet scrubbers, DSI, and SDA by July 1, 2023. A summary of DEC's Regional Haze findings are as follows:

Table III.K.13.F-30. Final Determination for Eielson Air Force Base

Pollutant	Regional Haze Controls	Regional Haze Determination	Effective Dates of Control/Limit
EUs 1 – 4 Coal-Fired Boilers - 120,000 lb/hr			
SO_2	Option 1 – Retire Existing EUs 1 – 4	Submit permit application with enforceable retirement dates	Submit application by July 1, 2023 Retirement effective no later than December 31, 2024
	Option 2 – Four Factor Analysis	Submit a four-factor analysis for DSI, wet scrubber, and SDA	Submit Four-Factor Analysis by July 1, 2023
EUs 5A – 6A Coal-Fired Boiler with DSI - 120,000 lb/hr			

Pollutant	Regional Haze Controls	Regional Haze Determination	Effective Dates of Control/Limit
SO_2	Already Effectively Controlled (0.20 lb/MMBtu emission rate with DSI)	No Additional Controls	N/A

e. U.S. Army, Doyon Utilities: Fort Wainwright

Fort Wainwright is a military installation located within and adjacent to the city of Fairbanks, Alaska, in the Tanana River Valley. The EUs located within the military installation at Fort Wainwright are either owned and operated by a private utility company, Doyon Utilities, LLC. (DU) under Title V Operating Permit AQ1121TVP02 Revision 2, or by U.S. Army Garrison Fort Wainwright (Fort Wainwright or FWA) under Title V Operating Permit AQ0236TVP04. The two entities, DU and FWA, comprise a single stationary source operating under two permits. The stationary source includes coal-fired boilers for a combined heat and power plant, as well as emergency generator engines, fire pump engines, backup diesel fired boilers, and waste oil-fired boilers. These EUs are listed below in Table III.K.13.F-31 and Table III.K.13.F-32.

Table III.K.13.F-31. DU Fort Wainwright Emission Unit Inventory

EU ID1	Description of EU	Rating/Size		Location
1	Coal-Fired Boiler 3	230	MMBtu/hr	Central Heating and Power Plant (CHPP)
2	Coal-Fired Boiler 4	230	MMBtu/hr	CHPP
3	Coal-Fired Boiler 5	230	MMBtu/hr	CHPP
4	Coal-Fired Boiler 6	230	MMBtu/hr	CHPP
5	Coal-Fired Boiler 7	230	MMBtu/hr	CHPP
6	Coal-Fired Boiler 8	230	MMBtu/hr	CHPP
7a	South Coal Handling Dust Collector DC-01	13,150	acfm	CHPP
7b	South Underbunker Dust Collector DC-02	884	acfm	CHPP
7c	North Coal Handling Dust Collector NDC-1	9,250	acfm	CHPP
8	Backup Generator Engine	2,937	hp	CHPP
9	Emergency Generator Engine	353	hp	Building 1032
14	Emergency Generator Engine	320	hp	Building 1563
22	Emergency Generator Engine	35	hp	Building 3565
23	Emergency Generator Engine	155	hp	Building 3587
29	Emergency Pump Engine	75	hp	Building 1056
30	Emergency Pump Engine	75	hp	Building 3403
31	Emergency Pump Engine	75	hp	Building 3724
32	Emergency Pump Engine	75	hp	Building 4162
33	Emergency Pump Engine	75	hp	Building 1002
34	Emergency Pump Engine	220	hp	Building 3405

EU ID1	Description of EU	Rating/Size		Location
35	Emergency Pump Engine	55	hp	Building 4023
36	Emergency Pump Engine	220	hp	Building 3563
51a	DC-1 Fly Ash Dust Collector	3,620	acfm	CHPP
51b	DC-2 Bottom Ash Dust Collector	3,620	acfm	CHPP
52	Coal Storage Pile	N/A		CHPP

Table III.K.13.F-32. U.S. Army Garrison Fort Wainwright Emission Unit Inventory

EU ID	Description of EU	Rating/Size		Location
8	Backup Diesel-Fired Boiler 1	19	MMBtu/hr	Basset Hospital
9	Backup Diesel-Fired Boiler 2	19	MMBtu/hr	Basset Hospital
10	Backup Diesel-Fired Boiler 3	19	MMBtu/hr	Basset Hospital
11	Backup Diesel-Electric Generator 1	900	kW	Basset Hospital
12	Backup Diesel-Electric Generator 2	900	kW	Basset Hospital
13	Backup Diesel-Electric Generator 3	900	kW	Basset Hospital
22	VOC Extraction and Combustion	N/A		
23	Fort Wainwright Landfill	1.97	million cubic meters	
24	Aerospace Activities	N/A		
26	Emergency Generator	324	hp	Building 2132
27	Emergency Generator	67	hp	Building 1580
28	Emergency Generator	398	hp	Building 3406
29	Emergency Generator	47	hp	Building 3567
30	Fire Pump	275	hp	Building 2089
31	Fire Pump #1	235	hp	Building 1572
32	Fire Pump #2	235	hp	Building 1572
33	Fire Pump #3	235	hp	Building 1572
34	Fire Pump #4	235	hp	Building 1572
35	Fire Pump #1	240	hp	Building 2080
36	Fire Pump #2	240	hp	Building 2080
37	Fire Pump	105	kW	Building 3498
38	Fire Pump #1	120	hp	Building 5009
39	Fire Pump #2	120	hp	Building 5009
40	Waste Oil-Fired Boiler	2.6	MMBtu/hr	Building 5007
50	Emergency Generator Engine	762	hp	Building 1060
51	Emergency Generator Engine	762	hp	Building 1060
52	Emergency Generator Engine	82	hp	Building 1193
53	Emergency Generator Engine	587	hp	Building 1555
54	Emergency Generator Engine	1,059	hp	Building 2117
55	Emergency Generator Engine	212	hp	Building 2117
56	Emergency Generator Engine	176	hp	Building 2088
57	Emergency Generator Engine	212	hp	Building 2296
58	Emergency Generator Engine	71	hp	Building 3004
59	Emergency Generator Engine	35	hp	Building 3028
60	Emergency Generator Engine	95	hp	Building 3407

EU ID	Description of EU	Rating/Size	Location
61	Emergency Generator Engine	50 hp	Building 3703
62	Emergency Generator Engine	18 hp	Building 5108
63	Emergency Generator	68 hp	Building 1620
64	Emergency Generator	274 hp	Building 1054
65	Emergency Generator	274 hp	Building 4390
???	Distillate Fired Boilers (23)	Varies	Varies
???	Waste Oil-Fired Boiler	2.5 gal/hr	Building 3476
???	Waste Oil-Fired Boiler	2.5 gal/hr	Building 3476

Fort Wainwright recently went through an emissions control analysis as a part of the planning requirements triggered when the FNSB nonattainment area was designated as "Serious" with respect to nonattainment of the 2006 24-hour $PM_{2.5}$ NAAQS, which was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706. CAA section 189(b)(1)(B) and 40 C.F.R. § 51.1010 describe the Serious area attainment plan requirements for BACM/BACT. Large stationary sources are a subgroup of emissions sources that are given special attention in the required BACM/BACT analysis. Per federal requirement, DEC evaluated all point sources with emissions greater than 70 TPY of $PM_{2.5}$ or for any individual $PM_{2.5}$ precursor (NO_x, SO_2, NH_3, VOCs).

This evaluation resulted in the following emissions controls contained in Table III.K.13.F-33, which are those required in Table 7.7-11 of the Amendments to: State Air Quality Control Plan Vol II: III.D.7.7 Control Strategies document; adopted November 19, 2019.[3]

Table III.K.13.F-33. BACT and SIP Findings Summary Table for Fort Wainwright

Pollutant	BACT Emission Limit	BACT Control Device or Operational Limitation	Effective Dates of Control/Limit
EUs 1 through 6 - Coal Fired Boilers - 230 MMBtu/hr (each)			
NO_x	Precursor Demonstration*	No additional control	N/A
$PM_{2.5}$	0.045 lb/MMBtu (3-hr avg.)	Full Stream Baghouse	Existing
SO_2	0.25% sulfur by weight	Certified Statement of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
	0.12 lb/MMBtu (3-hr avg.)	Dry Sorbent Injection (DSI)	Title I Permit App. by June 9, 2020 Effective no later than October 1, 2023
Emergency Engines, Generators, and Fire Pumps			
NO_x	Precursor Demonstration*	No additional control	N/A
$PM_{2.5}$	0.015 - 1.0 g/hp-hr (3-hr avg.)	Good Combustion Practices and Limited Operation	Existing

Pollutant	BACT Emission Limit	BACT Control Device or Operational Limitation	Effective Dates of Control/Limit
SO_2	15 ppmw sulfur in fuel	Certified Statement of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
Fuel Oil Boilers			
NO_x	Precursor Demonstration*	No additional control	N/A
$PM_{2.5}$	0.012 lb/MMBtu (3-hr avg.)	Good Combustion Practices and Limited Operation	Existing
SO_2	15 ppmw sulfur in fuel	Certified Statement of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
Material Handling Sources (Coal Prep and Ash Handling)			
$PM_{2.5}$	0.0025 - 0.02 gr/dscf	Enclosed Emission Points and Good Operating Practices	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021

Section II.B.3.f. of the Guidance Document discusses selecting sources that have recently undergone emission control technology review. The Guidance Document states the following:

> "New, reconstructed, or modified emission units that went through Best Available Control Technology (BACT) review under the Prevention of Significant Deterioration (PSD) program or Lowest Achievable Emission Rate (LAER) review under the nonattainment new source review program for major sources and received a construction permit on or after July 31, 2013,46 on a pollutant-specific basis. The statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress."

DEC Regional Haze Findings for Fort Wainwright CHPP

DEC's recent analysis of Fort Wainwright for the Serious nonattainment area resulted in a limit on the sulfur content of the coal received at the stationary source as well as the requirement to install dry sorbent injection to control SO_2 on the coal-fired boilers. Additionally, the diesel-fired engines and boilers were also required to combust ULSD. Taking into consideration the BACT analysis recently performed for the nonattainment area and the sulfur limits already imposed by this effort, DEC will not further evaluate Fort Wainwright for the second implementation period of RH planning. In addition to the previously performed BACT analysis requiring DSI, DU subsequently provided additional cost analyses for dry sorbent injection, spray dry absorbers, and wet scrubbers, which are included in the appendix to this chapter, Appendix III.K.13.F. A summary of DEC's RH findings are as follows:

Table III.K.13.F-34. Final Determination for Fort Wainwright CHPP

Pollutant	Regional Haze Controls	Regional Haze Determination	Effective Dates of Control/Limit
EUs 1 through 6 - Coal-Fired Boilers - 230 MMBtu/hr (each)			
SO_2	Already Effectively Controlled (0.12 lb/MMBtu with DSI; 0.25% sulfur by weight in coal)*	No Additional Controls	N/A

* Background and detailed information regarding Fairbanks $PM_{2.5}$ State Implementation Plan (SIP) can be found at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/.

f. University of Alaska: Fairbanks Campus Power Plant

The Fairbanks Campus Power Plant is owned and operated by the University of Alaska Fairbanks (UAF), and UAF is the Permittee for the stationary source's Title V Operating Permit AQ0316TVP02 Revision 1. The SIC code for the stationary source is 8211 – Colleges, Universities, and Professional Schools.

The Fairbanks Campus Power Plant is a co-generation power plant that is designed to supply electrical power and heat to the campus. The fuel consuming EUs consists of a 295.6 MMBtu/hr coal/woody biomass-fired boiler, two dual fuel-fired 180.9 MMBtu/hr boilers, a medical/pathological waste incinerator, and diesel-fired generators and boilers. These EUs are listed below in Table III.K.13.F-35.

Table III.K.13.F-35. Fairbanks Campus Power Plant Emission Unit Inventory

EU ID	Description of EU	Rating / Size		Fuel Type	Installation or Construction Date
3	Dual-Fired Boiler	180.9	MMBtu/hr	Dual Fuel	1970
4	Dual-Fired Boiler	180.9	MMBtu/hr	Dual Fuel	1987
8	Peaking/Backup Diesel Generator	13,266	hp	Diesel	1999
9A	Medical/Pathological Waste Incinerator	83	lb/hr	Medical / Infectious Waste	2006
19	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
20	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
21	Diesel Boiler	6.13	MMBtu/hr	Diesel	2004
23	Diesel Generator Engine	235	kW	Diesel	2003
24	Diesel Generator Engine	51	kW	Diesel	2001

EU ID	Description of EU	Rating / Size		Fuel Type	Installation or Construction Date
26	Diesel Generator Engine	45	kW	Diesel	1987
27	Diesel Generator Engine	500	hp	Diesel	TBD
28	Diesel Generator Engine	120	hp	Diesel	1998
29	Diesel Generator Engine	314	hp	Diesel	2013
105	Limestone Handling System	1,200	acfm	N/A	2019
107	Sand Handling System	1,600	acfm	N/A	2019
109	Ash Handling System	1,000	acfm	N/A	2019
110	Ash Handling System Vacuum	2,000	acfm	N/A	2019
111	Ash Loadout to Truck	N/A		N/A	2019
113	Dual Fuel-Fired Circulating Fluidized Bed (CFB) Boiler	295.6	MMBtu/hr	Coal/Woody Biomass	2019
114	Dry Sorbent Handling Vent Filter Exhaust	5	acfm	N/A	2019
128	Coal Silo No. 1 with Bin Vent	1,650	acfm	N/A	2019
129	Coal Silo No. 2 with Bin Vent	1,650	acfm	N/A	2019
130	Coal Silo No. 3 with Bin Vent	1,650	acfm	N/A	2019

The Fairbanks Campus Power Plant recently went through an emissions control analysis as a part of the planning requirements triggered when the FNSB nonattainment area was designated as "Serious" with respect to nonattainment of the 2006 24-hour $PM_{2.5}$ NAAQS, which was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706. CAA section 189(b)(1)(B) and 40 C.F.R. § 51.1010 describe the Serious area attainment plan requirements for BACM/BACT. Large stationary sources are a subgroup of emissions sources that are given special attention in the required BACM/BACT analysis. Per federal requirement, DEC evaluated all point sources with emissions greater than 70 TPY of $PM_{2.5}$ or for any individual $PM_{2.5}$ precursor (NO_x, SO_2, NH_3, VOCs).

This evaluation resulted in the following emissions controls contained in Table III.K.13.F-36, which are those required in Table 7.7-16 of the Amendments to: State Air Quality Control Plan Vol II: III.D.7.7 Control Strategies document; adopted November 19, 2019.[3]

Table III.K.13.F-36. BACT and SIP Findings Summary Table for Fairbanks Campus Power Plant

Pollutant	BACT Emission Limit	BACT Control Device or Operational Limitation	Effective Dates of Control/Limit
Dual Fuel-Fired Boiler – 295.6 MMBtu/hr			
NO_x	Precursor Demonstration*	No additional control	N/A
$PM_{2.5}$	0.012 lb/MMBtu	Fabric Filters (Baghouse)	Existing
SO_2	0.25% sulfur by weight	Certified Statement of Sulfur Content	Title I Permit App. by June 9, 2020

Pollutant	BACT Emission Limit	BACT Control Device or Operational Limitation	Effective Dates of Control/Limit
			Effective no later than June 9, 2021
	0.2 lb/MMBtu (30-day avg.)	No additional control	Existing
Diesel-Fired Engines			
NO_x	Precursor Demonstration*	No additional control	N/A
$PM_{2.5}$	0.015 - 1.0 g/hp-hr (3-hr avg.)	Positive Crankcase Ventilation, Good Combustion Practices, and Limited Operation	Existing
SO_2	15 ppmw sulfur in fuel	Certified Statement or Approved Analysis of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
EUs 3, 4, and 19 through 21 - Fuel Oil-Fired Boilers			
NO_x	Precursor Demonstration*	No additional control	N/A
$PM_{2.5}$	0.012 lb/MMBtu (Diesel 3-hr avg.) 0.0075 lb/MMBtu (N.G. 3-hr avg.)	Good Combustion Practices and Limited Operation	Existing
SO_2	1,000 ppmw sulfur in fuel (Diesel) 0.60 lb/MMscf (Natural Gas) October 1 – March 31	Certified Statement or Approved Analysis of Sulfur Content	Title I Permit App. by June 9, 2020 Effective no later than October 1, 2020
	15 ppmw sulfur in fuel (Diesel) 0.60 lb/MMscf (Natural Gas) October 1 – March 31	Certified Statement or Approved Analysis of Sulfur Content	Title I Permit App. by June 9, 2021 Effective no later than October 1, 2023
EU 9a – Pathogenic Waste Incinerator (83 lb/hr)			
NO_x	Precursor Demonstration*	No additional control	N/A
$PM_{2.5}$	4.67 lb/ton	Limited Operation and Multiple Chamber Design	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
SO_2	15 ppmw sulfur in liquid fuel	Certified Statement of Sulfur Content	Title I Permit App. by June 9, 2020

Pollutant	BACT Emission Limit	BACT Control Device or Operational Limitation	Effective Dates of Control/Limit
			Effective no later than June 9, 2021
Material Handling Sources (Coal Prep and Ash Handling)			
PM$_{2.5}$	0.003 - 0.050 gr/dscf	Enclosed Emission Points, fabric filters, and vents	Title I Permit App. by June 9, 2020 Effective no later than June 9, 2021
	5.50E-05 lb/ton	Enclosure Emission Points	

DEC's recent analysis of the Fairbanks Campus Power Plant for the Serious nonattainment area resulted in a limit on the sulfur content of the coal received at the stationary source. Additionally, the diesel-fired engines and pathogenic waste incinerator were also required to combust ULSD year-round, while the diesel-fired boilers were required to combust ULSD for half of the year from October through March. The Fairbanks Campus Power Plant also recently replaced two coal-fired boilers installed in 1962 with a new coal/woody biomass-fired circulating fluidized bed boiler that has considerably lower SO_2 emissions. Calendar year 2020 was the first year of new boiler operations after the retirement of the existing boilers and stationary source wide SO_2 emissions dropped from an average of 190.0 tons per year between 2014 through 2019 to 20.8 tons, an 89% decrease in emissions.

Section II.B.3.f. of the Guidance Document discusses selecting sources that have recently undergone emission control technology review. The Guidance Document states the following:

> "New, reconstructed, or modified emission units that went through Best Available Control Technology (BACT) review under the Prevention of Significant Deterioration (PSD) program or Lowest Achievable Emission Rate (LAER) review under the nonattainment new source review program for major sources and received a construction permit on or after July 31, 2013,46 on a pollutant-specific basis. The statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress."

DEC Regional Haze Findings for Fairbanks Campus Power Plant
Taking into consideration the BACT analysis recently performed for the nonattainment area and the sulfur limits already imposed by this effort, as well as the significant drop in SO_2 emissions as a result of replacing the existing coal-fired boilers, DEC will not further evaluate the Fairbanks Campus Power Plant for the second implementation period of RH planning. A summary of DEC's RH findings are as follows:

Table III.K.13.F-37. Final Determination for Fairbanks Campus Power Plant

Pollutant	Regional Haze Controls	Regional Haze Determination	Effective Dates of Control/Limit
EU 113 – Dual Fuel-Fired Boiler – 295.6 MMBtu/hr			
SO_2	Already Effectively Controlled (0.20 lb/MMBtu; 0.25% sulfur by weight in coal)*	No Additional Controls	N/A

* Background and detailed information regarding Fairbanks $PM_{2.5}$ State Implementation Plan (SIP) can be found at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/.