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October 6, 2025

Dan Opalski
Deputy Regional Administrator
Environmental Protection Agency, Region 10
1200 Sixth Avenue, Suite 155
Seattle, WA 98101

Subject: Alaska Regional Haze Second Implementation Period State Implementation Plan Clarification Memo

Dear Deputy Administrator Opalski,

On July 25, 2022, the Alaska Department of Environmental Conservation (DEC) submitted a State Implementation Plan (SIP) to the Environmental Protection Agency (EPA) to address the visibility protection requirements of Clean Air Act section 169A and 169B and the Regional Haze Rule requirements of 40 CFR 51.308 for the second implementation period. EPA has not yet acted on that submission. The 2022 Regional Haze SIP Submission included the following:

- Calculations of baseline, current, and natural conditions, progress to date, and the uniform rate of progress;
- Long-term strategy for regional haze, including the state's considerations of the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, the remaining useful life of any potentially affected anthropogenic source of visibility impairment, a description of the criteria the state used to determine which sources or groups of sources it evaluated, and a description how the four factors were taken into consideration in selecting measures;
- Reasonable progress goals;
- Monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment;
- Progress report;
- Determination of adequacy of the existing implementation plan; and
- Description of how the state addressed any comments provided by the Federal Land Managers and procedures for continuing consultation between the state and Federal Land Managers on the implementation of the visibility protection program.

With respect to the long-term strategy, DEC acknowledges that the 2022 Regional Haze SIP Submission relied in part on sulfur dioxide (SO_2) best available control technology (BACT) analyses and determinations for certain facilities and units originally submitted as part of the Fairbanks North Star Borough 2006 24-Hour $PM_{2.5}$ Serious Area and the 189(d) Plan submission made on December 13, 2019 and December 15, 2020, respectively. However, DEC subsequently revised the original SO_2 BACT analyses to address EPA concerns detailed in its proposed disapproval action on January 10, 2023 (88 FR 1454) and to account for more recent vendor quotes and fuel prices. These updated SO_2 BACT analyses were later submitted through the public process by DEC to EPA as part of a December 4, 2024 revision to the Fairbanks North Star Borough (FNSB) Serious Nonattainment Area (NAA) $PM_{2.5}$ SIP. The SIP is available at https://www.regulations.gov/document/EPA-R10-OAR-2024-0595-0078 for docket no. EPA-R10-OAR-2024-0595.

The 2022 Regional Haze SIP submission, as augmented by the December 4, 2024 SIP submission and clarified below, meets the requirements of sections 169A and 169B of the Clean Air Act and 40 CFR 51.308 for the second implementation period. Therefore, DEC is rescinding its June 3, 2025 conditional approval request, and DEC will not revise its SIP by submitting a Supplemental Regional Haze SIP Submission as described in that letter. DEC is sending this letter to make clear that it is the State's intention to rely on the updated BACT analyses for purposes of the Regional Haze SIP.

Clarifications from DEC's December 4, 2024, Fairbanks North Star Borough Nonattainment Area $PM_{2.5}$ (FNSB NAA $PM_{2.5}$) SIP Submission, and July 25, 2022, Regional Haze SIP Submission

Regarding University of Alaska Fairbanks (UAF) Campus:

- The July 25, 2022 Regional Haze SIP submission used 2017 emissions inventory data to select sources for further analysis. However, the submission did not consider that in 2019 the original coal-fired boilers at this facility were decommissioned and replaced with a modern circulating fluidized bed coal-fired boiler equipped with a limestone injection system which controls SO_2 emissions.
- DEC has determined that current, actual emissions of SO_2 from this facility are so low that the facility screens-out of additional review based on the Quantity over distance (Q/d) source selection methodology. The UAF Campus emitted 7.4 tons of SO_2 emissions in 2023 and is 117 kilometers from Denali National Park.
- Based on the information provided above, DEC has removed the UAF Campus from DEC's list of sources requiring further analysis as described in more detail in Section 2 of the enclosed document entitled, "2025 Review of Alaska's Potential Controllable Sources."

Regarding Golden Valley Electric Association's (GVEA) North Pole Power Plant:

- DEC evaluated firing ultra-low sulfur diesel (ULSD) year-round in EUs 1 and 2 at this facility as part of the SO_2 BACT analysis in the 2024 FNSB NAA $PM_{2.5}$ SIP Submission. DEC estimated that for ULSD, the SO_2 removal cost for EUs 1 and 2 would be between \$6,629 and \$13,932/ton based on potential to emit and between \$6,723 and \$14,026/ton based on potential to emit, respectively (depending on fuel price). The documentation for this determination can be found on Regulations.gov for docket no. EPA-R10-OAR-2024-0595 here: https://www.regulations.gov/document/EPA-R10-OAR-2024-0595-0078

- DEC obtained updated fuel costs for the various fuel types provided to GVEA from Petro Star, Inc. These updated fuel prices included a change in the price difference between No. 1 and No. 2 fuel oil that means No. 1 fuel oil is not cost effective for EUs 1 and 2. Therefore, the North Pole Power Plant will no longer have a requirement to switch to No. 1 fuel oil on EUs 1 and 2. The updated analysis is enclosed in Section 3a of the enclosed document, "2025 Review of Alaska's Potential Controllable Sources."
- DEC has determined that firing ULSD in EUs 1 and 2 would not be cost-effective based on actual emissions for purposes of the regional haze long-term strategy.
- DEC evaluated requiring USLD year-round in EUs 5 and 6 at this facility as part of the SO_2 BACT analyses in the FNSB NAA $PM_{2.5}$ SIP submitted on December 4, 2024. DEC estimated that for ULSD, the SO_2 removal cost for EUs 5 and 6 would be over $2.5 million per ton of SO_2 removed based on potential to emit. Both units currently fire light-straight run (LSR), or naphtha, an inherently low sulfur fuel. The documentation for this determination can be found on Regulations.gov for docket no. EPA-R10-OAR- 2024-0595 at https://www.regulations.gov/document/EPA-R10-OAR-2024-0595-0078.
- DEC has determined that firing ULSD in EUs 5 and 6 would not be cost-effective based on actual emissions for purposes of the regional haze long-term strategy.
- Based on the information provided above, DEC has determined that it is economically infeasible to switch to ULSD for EUs 1, 2, 5, and 6 or to No. 1 fuel oil for EUs 1 and 2 at the North Pole Power Plant. Therefore, no reductions or emission controls were selected for North Pole Power Plant under the Regional Haze rule.

Regarding Golden Valley Electric Association's (GVEA's) Healy Power Plant:

- In the 2022 Regional Haze Plan SIP Submission, DEC completed a four-factor analysis on EU 1 because it was probable that the EU would be retiring. Based on the comprehensive best available retrofit technology (BART) analysis during the first implementation period, DEC determined that additional controls outside of DSI would not be cost effective. Therefore, to ensure SO_2 controls were fully evaluated, DEC articulated three options from EU 1: (1) retire Unit 1 by 2024, (2) submit a four-factor analysis for dry sorbent injection (DSI) optimization, or (3) accept a 0.20 lb/MMBtu SO_2 limit.
- After the 2022 Regional Haze Plan SIP Submission, GVEA elected to install SCR on EU 1 and continue operating the unit.
- GVEA submitted a four-factor analysis for optimizing DSI on June 30, 2023, with the conclusion that their DSI system could not achieve an SO_2 emissions rate lower than EU 1's current emissions limit of 0.30 lb/MMBtu through increased sorbent injection rates alone.
- DEC also reevaluated whether DSI optimization is necessary for reasonable progress based on the four statutory factors. Additional details of DEC's supplemental evaluation are in Section 3b of the enclosed document entitled "2025 Review of Alaska's Potential Controllable Sources." Based on this reevaluation which used DSI cost estimates from sources in the FNSB Serious NAA $PM_{2.5}$ SIP, DEC has determined that it is cost ineffective

to upgrade the DSI control system on the Healy Power Plant EU1. This analysis confirms the conclusion from the previous BART analysis.

- As stated in the 2022 Regional Haze Plan SIP Submission, further SO_2 control technology retrofits on EU 1 are not necessary for reasonable progress and EU 1 remains effectively controlled based on the existing 0.30 lb/MMBtu SO_2 limit embodied in a 2012 federal consent decree and approved by the EPA as BART.
- On April 8, 2025, GVEA Healy EU 1 received a Presidential Exemption from MATS compliance until July 2029. It is reasonable to assume that GVEA would time any upgrade to the DSI system to coincide with work to install activated carbon injection ports for MATS compliance.
- In the Regional Haze SIP for the second implementation period, DEC determined that the 54-MW TRW Integrated Entrained Combustion System (EU 2) at GVEA's Healy Power Plant is effectively controlled, with the unit's existing SO_2 emissions rate of 0.10 lb/MMBtu achieved using a Spray Dry Absorber control system. This requirement is embodied in a 2012 federal consent decree.

Regarding Aurora Energy's Chena Power Plant:

- DEC evaluated retrofitting EUs 4 through 7 at this facility with SO_2 emissions controls as part of the SO_2 BACT analyses in the FNSB NAA $PM_{2.5}$ SIP submitted on December 4, 2024. DEC determined that due to space constraints, it would not be technically feasible to install wet flue gas desulfurization (WFGD), circulating dry scrubbers (CDS), or SDA on EUs 4 through 7. Additionally, DEC determined that for DSI, the SO_2 removal cost would be $13,368/ton based on potential to emit. The documentation for this determination can be found on Regulations.gov for docket no. EPA-R10-OAR-2024-0595 at https://www.regulations.gov/document/EPA-R10-OAR-2024-0595-0078.
- SO_2 emission limits were included in the power plant's operating permit under the FNSB NAA $PM_{2.5}$ SIP and included as regulatory required controls in the Second Implementation Regional Haze SIP. However, further studies determined that the controls did not meaningfully contribute to reducing $PM_{2.5}$ emissions in the Nonattainment Area. The documentation for this determination can be found in the Modeling Chapter for the FNSB NAA $PM_{2.5}$ SIP, available at https://dec.alaska.gov/media/rs4pmcfa/iiid708-modeling.pdf.
- DEC determined that retrofitting EUs 4 through 7 with a DSI system would not be cost effective based on actual SO_2 emissions for purposes of the Regional Haze long-term strategy.
- Based on the information provided above, DEC has determined that it is technically infeasible to install WFGD, CDS, or SDA based on space constraints, and it is not cost effective to install DSI on the coal-fired boilers at the Chena Power Plant. Therefore, no further emissions reductions or emissions controls are selected for the Chena Power Plant for the 2025 RH Clarifications Memo. Further analysis is described in more detail in Section 3c of the enclosed document entitled, "2025 Review of Alaska's Potential Controllable Sources."

Regarding Eielson Air Force Base (Eielson) Combined Heating and Power Plant:

- In 2010, DEC authorized a phased replacement of the base's six existing older coal-fired boilers without SO_2 controls with five new boilers that are designed to accommodate DSI systems to control SO_2 emissions. The sixth boiler was to be removed without a replacement. The first boiler was replaced in 2014 and a second in 2016. The other four original boilers remain onsite and continue to operate without SO_2 emission controls. With the boiler replacement project halted, DEC required the facility to do a Four Factor Analysis in 2023 for the installation of SO_2 pollution control technologies including WFGD, DSI, and SDA. Based on the results of this 2023 analysis, Eielson concluded that retrofitting the boilers with any SO_2 emission controls would be cost prohibitive.

  DEC revised Eielson's analysis with conservative assumptions which also showed that retrofitting the older coal-fired boilers with new SO_2 emissions controls would be cost prohibitive for Regional Haze. Further analysis is described in more detail in Section 3d of the enclosed document entitled, "2025 Review of Alaska's Potential Controllable Sources."

- To further analyze the costs of retrofitting SO_2 controls on Eielson's four legacy coal-fired boilers EUs 1 through 4, DEC reviewed the SO_2 BACT analysis that was conducted as part of the 2024 FNSB NAA $PM_{2.5}$ SIP Submission, for the similar size and era EUs 1 through 6 at Fort Wainwright. As previously mentioned, DEC estimated that the lowest cost control option of DSI would cost $6,636/ton of SO_2 removed based on potential to emit. However, this BACT analysis was based on the Fort Wainwright coal-fired boiler's combined potential emissions of 1,470 tons of SO_2, which is substantially more than the 212 tons of combined SO_2 emissions emitted in 2023 from EUs 1 through 4 at Eielson that would be used in a four-factor analysis.

  Therefore, DEC concludes that SO_2 controls would be cost prohibitive to install on Eielson's EUs 1 through 4 for the regional haze second implementation period. The documentation for this determination can be found on Regulations.gov for docket no. EPA-R10-OAR-2024-0595 at https://www.regulations.gov/document/EPA-R10-OAR-2024-0595-0078.

- In the 2022 Regional Haze Plan SIP Submission, DEC stated that Eielson's newer coal-fired boilers, EUs 5A and 6A, were already effectively controlled with DSI and an existing SO_2 emissions limit of 0.20 lb/MMBtu to comply with the performance standard for industrial-commercial-institutional steam generating units (NSPS Db). DEC further stated that SO_2 emissions from EUs 5A and 6A have been extremely low (5.9 tons in 2017, 22 tons in 2018, and 3.7 tons in 2019). Because this limit is embodied in a Federal NSPS standard and emissions from EUs 5A and 6A are documented in the submission as being extremely low, the existing limit is not necessary for reasonable progress in the regional haze second implementation period.

Regarding U.S. Army Garrison Fort Wainwright's Central Heating and Power Plant (CHPP):

- DEC evaluated retrofitting Units 1 through 6 at this facility with a DSI system as part of the SO_2 BACT analyses in the Fairbanks $PM_{2.5}$ SIP submitted on December 4, 2024. The Alaska DEC estimated that for DSI, the SO_2 removal cost would be $6,636/ton based on potential to emit. DEC also determined the cost effectiveness of retrofitting Units 1 through 6 with CDS, WFGD, and SDA ranged from over $13,000 per ton to over $20,000 per ton of SO_2 removed based on potential to emit. The documentation for this determination can be found on Regulations.gov for docket no. EPA-R10-OAR-2024-0595 at https://www.regulations.gov/document/EPA-R10-OAR-2024-0595-0078.
- SO_2 emission limits were implemented in the facility's operating permit under the FNSB NAA $PM_{2.5}$ SIP and included as regulatory required controls in the Second Implementation Regional Haze SIP. However, further studies determined that the controls did not meaningfully contribute to reducing $PM_{2.5}$ emissions in the Nonattainment Area. The documentation for this finding can be found in the Modeling Chapter for the FNSB NAA $PM_{2.5}$ SIP, available at https://dec.alaska.gov/media/rs4pmcfa/iiid708-modeling.pdf.
- DEC has determined that retrofitting EUs 1 through 6 with a DSI system would not be cost effective based on actual SO_2 emissions for purposes of the regional haze long-term strategy.
- Based on the information provided above, DEC has determined that it is economically infeasible to install CDS, WFGD, SDA, or DSI on the coal-fired boilers at the Fort Wainwright Power Plant. Therefore, no further emission reductions or emission controls were selected for EUs 1 through 6. Further analysis is described in Section 3e of the enclosed document entitled, "2025 Review of Alaska's Potential Controllable Sources."

As described above, analyses conducted on Alaska's anthropogenic sources indicated that the sources are effectively controlled or that additional emission controls would be economically infeasible. DEC further contends that visibility in each of Alaska's Class I areas is already achieving natural conditions.

However, many of the most significant impacts on Alaska's visibility are uncontrollable sources unique to the state and not properly accounted for in the modeling platforms available to DEC. Some of these impacts are illustrated in the results of a modeling effort conducted by EPA and described in the report entitled, "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling for Hawaii, Virgin Islands, and Alaska." Modeling results demonstrated that even after accounting for international anthropogenic emissions and removing all U.S. anthropogenic sources, the forecasted 2028 Most Impaired Day annual average deciview value remained above the uniform rate of progress and the point almost identical to the unadjusted forecast at all four stations. This indicates that any visibility impairment above natural conditions is most likely due to uncontrollable natural sources. It also indicates that imposing additional emission restrictions on industrial sources such as the coal-fired boilers at the Golden Valley Electric Association Healy Power Plant or Eielson Air Force Base will not result in decreased visibility impairment at Denali National Park. DEC discusses this assertion in more detail in the enclosed document entitled "Alaska's Class I Area Visibility."

Thank you for your time and attention to this matter. For any questions, please contact Director Jason Olds at Jason.Olds@alaska.gov.

Sincerely,

Randy Bates
Commissioner

Enclosures: 2025 Review of Alaska's Potential Controllable Sources
Alaska's Class I Area Visibility

cc: Jason Olds, Director, Air Quality

Enclosure 1: 2025 Review of Alaska's Potential Controllable Sources

Enclosure 1: 2025 Review of Alaska's Potential Controllable Sources

1. Overview/Purpose

40 CFR §51.308(f)(2)(i) of the Regional Haze (RH) Rule requires states to periodically revise and submit their State Implementation Plans (SIPs) to ensure continued improvement in visibility conditions at Class I federal areas. A state's RH SIP submission must include a long-term strategy (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 this LTS, the state selects sources for review (based on their impact on visibility conditions at Class I federal areas) and considers four factors for potential control measures for the selected sources: 1) cost of compliance; 2) time necessary to achieve 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," (2019 Guidance Document).

In support of the 2025 RH Clarifications Memo, the Alaska Department of Environmental Conservation (DEC) reviewed the updated actual emissions for the six stationary sources that were previously selected for review in the 2022 RH SIP. DEC reviewed the 2023 actual emissions as reported through the National Emissions Inventory (NEI) and performed an updated Q/d analysis, as outlined in Section 2 of this report. A list of the five sources selected for evaluation based on the updated Q/d analysis are shown in Table A.

Table A - Facility Selection for Review

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

2. Source Selection

To determine which stationary sources to carry forward for a four-factor analysis in the 2025 update, DEC reviewed the updated actual emissions from the sources that were previously selected in the 2022 RH SIP. These six sources were selected for review in the 2022 RH SIP using a Q/d analysis (i.e., actual SO_2 emissions from the source in 2017 (Q) / distance from the nearest Class I federal area (d)). If the Q/d ratio for a given source was calculated to be 1.0 or greater, then the source was selected for review in the 2022 RH SIP. For the 2025 updated source review, DEC reviewed the 2023 actual SO_2 emissions as reported through the NEI for these six stationary sources and performed an updated Q/d analysis. The updated Q/d analysis used the same 1.0 threshold used for the 2022 RH SIP to determine whether a source warranted further review.

The University of Alaska Fairbanks Campus (UAF Campus) had two coal-fired boilers EUs 1 and 2 in operation during the 2017 NEI year with 126.6 tons of SO_2 emissions combined. Those two EUs have since retired and been replaced by a new dual fuel-fired boiler EU 113, that primarily burns coal and is equipped with fluidized bed limestone injection controls. Consequently, the 2023 SO_2 NEI emissions reported for UAF Campus's emissions unit inventory were 7.4 tons. Based on the UAF Campus's reported actual SO_2 emissions of 7.4 tons for the year 2023 and the facility's distance from Denali National Park of 117 kilometers, the updated Q/d calculation for the UAF Campus results in a ratio of 0.1. A Q/d ratio of 0.1 is well below the 1.0 threshold set by DEC to determine whether a source warrants further review. Therefore, in this updated 2025 source review, the UAF Campus has been removed from DEC's list of sources that require further analysis.

Golden Valley Electric Association's (GVEA's) North Pole Power Plant (NPPP) had actual SO_2 emissions in 2023 of 38.9 tons, which resulted in a Q/d ratio of 0.32. However, in 2023 the NPPP had SO_2 fuel limits in place from the Fairbanks North Star Borough $PM_{2.5}$ Serious Nonattainment Area (FNSB NAA) SIP that have since been rescinded. Therefore, when calculating Q/d for the NPPP, the Department used 2024 actual emissions which were not impacted by the limits from FNSB NAA SIP. GVEA reported actual SO_2 emissions of 148 tons in 2024, which resulted in an updated Q/d ratio of 1.2. Therefore, DEC included the NPPP in the updated 2025 source review for further analysis which is discussed in more detail below.

After completing the source selection process as described above for the rest of the sources previously selected in the 2022 RH SIP (i.e., performing an updated Q/d analysis for each of the six sources), DEC has identified five sources that warrant further evaluation in this updated 2025 source review, which are listed below in Table B.

Table B - 2025 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	148.0	1.2	3.a
Healy Power Plant	Denali N.P.	6	319.0	53.2	3.b

Facility	Nearest Monitor	Distance to Monitor d (km)	Quantity of SO_2 Emissions Q (tpy)	Q/d SO_2	Section Number
Chena Power Plant	Denali N.P.	119	228.6	1.9	3.c
Eielson Air Force Base	Denali N.P.	133	233.7	1.8	3.d
Fort Wainwright	Denali N.P.	119	397.9	3.3	3.e

3. Four-Factor Analysis

a. Golden Valley Electric Association, North Pole Power Plant (NPPP)

Introduction and 2022 RH SIP Findings

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 C. The stationary source also owns insignificant EUs that include several gas-fired heaters.

Table C - GVEA 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 Note: [1] Estimated installation is 2024.

For the 2022 RH SIP analysis for the NPPP, DEC partially relied upon findings contained in the FNSB NAA SIP that required fuel switches for the turbines contained at the stationary source. However, the SO_2 BACT requirements contained in the 2019/2020 FNSB NAA SIP were withdrawn by DEC on September 25, 2023. An updated BACT analysis was included with the submittal of the 2024 FNSB SIP Amendment,[1] which contained a major source precursor demonstration for SO_2 emissions. Therefore, DEC has performed a new four factor analyses for SO_2 emissions on the turbines.

In the 2022 RH SIP, DEC compiled a list of SO_2 emissions at the stationary source using the NEI submissions for years 2014-2019 which can be seen in Table D. As can be seen in Table D, EUs 1, 2, and 5 are the only EUs with sizeable SO_2 emissions over the past 6 years. Therefore, DEC chose to perform a four-factor analysis of the NPPP on EUs 1, 2, and 5. This decision to analyze EUs 1, 2, and 5 has been carried forward into the updated 2025 source review as the back-up generator, EU 7, and the 5 MMBtu/hr propane-fired boilers, EUs 11 and 12, continue to emit negligible amounts of SO_2 emissions.

Table D - North Pole Power Plant SO_2 Emissions

<table>
<tr><th>Calendar Year</th><th>EU ID</th><th>SO2 Emitted (tons) Emissions Inventory</th><th>SO2 Emitted (tons) Emissions Inventory</th></tr>
<tr><td rowspan="6">2019</td><td>1</td><td>17.04</td><td rowspan="6">268.4</td></tr>
<tr><td>2</td><td>251.03</td></tr>
<tr><td>5</td><td>0.32</td></tr>
<tr><td>7</td><td>0.00</td></tr>
<tr><td>11</td><td>0.00</td></tr>
<tr><td>12</td><td>0.00</td></tr>
<tr><td rowspan="6">2018</td><td>1</td><td>19.8</td><td rowspan="6">215.2</td></tr>
<tr><td>2</td><td>189.84</td></tr>
<tr><td>5</td><td>5.58</td></tr>
<tr><td>7</td><td>0.00</td></tr>
<tr><td>11</td><td>0.00</td></tr>
<tr><td>12</td><td>0.00</td></tr>
<tr><td rowspan="6">2017</td><td>1</td><td>31.68</td><td rowspan="6">269.5</td></tr>
<tr><td>2</td><td>228.87</td></tr>
<tr><td>5</td><td>8.89</td></tr>
<tr><td>7</td><td>0.00</td></tr>
<tr><td>11</td><td>0.00</td></tr>
<tr><td>12</td><td>0.00</td></tr>
<tr><td rowspan="2"></td><td>1</td><td>37.87</td><td rowspan="2"></td></tr>
<tr><td>2</td><td>190.76</td></tr>
</table>

[1] DEC's 2024 FNSB NAA SIP Amendment: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-2024-amendment-serious-sip/.

Calendar Year	EU ID	SO_2 Emitted (tons) Emissions Inventory	SO_2 Emitted (tons) Emissions Inventory
2016	5	11.20	239.8
	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	

2022 DEC Regional Haze Findings for GVEA's North Pole Power Plant

After performing four-factor analyses for switching the turbines, EUs 1 and 2, to ULSD and No. 1 fuel oil, and EU 5 to ULSD, DEC found that it was 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 was predicated on the assumption that GVEA would be able to purchase No. 1 fuel oil from the Petro Star North Pole Refinery (PSNPR). If the PSNPR was not able to supply GVEA with No. 1 fuel oil due to shortages in supply, the NPPP could continue to burn No. 2 fuel oil in EUs 1 and 2 until such time as No. 1 fuel oil is again available to GVEA's NPPP. A summary of DEC's 2022 RH SIP findings is listed below:

Table E - 2022 RH SIP 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.

2025 Updated RH SO_2 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.

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 F.

Table F - 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

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.).

Identification of SO_2 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:

Ultra Low Sulfur Diesel (ULSD)
ULSD has a fuel sulfur content of 0.0015 % S by wt. or less. Combusting ULSD as the primary fuel would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines have historically mostly combusted No. 2 fuel oil that has a sulfur content averaging around 0.3 % S by weight.[2] Switching to ULSD 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.

No. 1 Fuel Oil (maximum sulfur content of 0.1 % S by wt.)
The No. 1 fuel oil available from the PSNPR comes in two different grades, a high sulfur version (HSHO#1) with a sulfur content of < 0.14 % S by wt. (1,400 ppmw) and a low sulfur version (LSHO#1) with a sulfur content of < 0.10 % S by wt. (1,000 ppmw). Combusting fuel with a sulfur content of 0.10 % to 0.14 % S by wt. as the primary fuel would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines mostly combust No. 2 fuel oil that has a sulfur content of around 0.30 % S by weight. Switching to No. 1 fuel oil would result in an approximate 56% to 69% 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. However, the 2024 Amendment to the FNSB NAA SIP[3] required that heating oil sold inside the NAA had to meet the requirements of LSHO#1 for all sources except for the major stationary sources that went through the BACT process. Consequently, there is greater demand for LSHO#1, which has caused a shortage of LSHO#1 in the Fairbanks area or the NAA. Thus, PSNSR is not providing LSHO#1 to GVEA at this time. Therefore, HSHO#1 is the only type of No. 1 fuel oil available to GVEA.

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.

Rank 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 G):

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[2] Note that the 0.3% S by weight value for No. 2 fuel oil is from the 2022 NEI. The source did not combust No. 2 fuel oil in 2023 due to SO_2 BACT limits from the FNSB NAA SIP that have since been rescinded.
[3] DEC's 2024 FNSB NAA SIP Amendment: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-2024-amendment-serious-sip/.

Table G - Control Technologies

Control Technology	Control Level
Ultra Low Sulfur Diesel	99.5% Control
No. 1 Fuel Oil	57% - 69.3% Control

Table Note: Control technologies already required at the stationary source, including 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.

Evaluate the Most Effective Controls

GVEA provided an economic analysis for the FNSB NAA SIP BACT exercise for switching the fuel combusted in the simple cycle gas turbines to No. 1 fuel oil and ULSD. For the updated 2025 source review, DEC updated GVEA's cost analysis with new data provided by PSNPR on August 14, 2025, for the cost per gallon of ULSD, HSHO#1, and No. 2 fuel oils delivered to the NPPP from January through July of 2025.

Department Cost Analysis for SO_2 Emissions Controls from the Simple Cycle Gas Turbines

PSNPR sits adjacent to the NPPP and is the exclusive fuel supplier for the facility. Because the FNSB NAA SIP required all sales of heating oil in the NAA to be LSHO#1, there is not enough supply for the turbines at the NPPP. Therefore, DEC's updated cost analyses for EUs 1 and 2 calculated a cost per ton of SO_2 emissions removed resulting from a switch to ULSD and HSHO#1. There is no capital cost involved with this fuel switch for these EUs. 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 HSHO#1. From January through July 2025, the average price per gallon of ULSD delivered to the NPPP was $2.93. This price represents an increase of $0.65 more per gallon of fuel if the facility were to switch from No. 2 fuel oil which has a cost of $2.28 per gallon. During this same period, the average price per gallon for No. 1 fuel oil (HSHO#1) was $2.57, which is $0.29 more per gallon than the cost of No. 2 fuel oil at $2.28 per gallon. For the cost analysis, the Department used a conservative approach which included the total amount of fuel combusted by EUs 1 and 2 in the 2023 NEI. However, because the FNSB NAA SIP limits were in effect at the time, all the fuel that was combusted in the turbines in 2023 was No. 1 fuel oil and ULSD. Now that those BACT limits have been withdrawn, the NPPP has continued to combust No. 2 fuel oil as their primary fuel source. However, note that the only factor driving the cost effectiveness value is the price per gallon of fuel. Therefore, the cost effectiveness value is not affected by the total amount of gallons purchased, as the reduction in emissions is directly proportional to the amount of fuel purchased.

A summary of these analyses is shown in Table H and Table I.

Table H - DEC Economic Analysis for Technically Feasible SO_2 Controls for EU 1

Control Alternative	2023 SO_2 Emissions (tons)[4]	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	9.82	9.77	N/A	$289,614	$29,646
No. 1 Fuel Oil (HSHO#1)	9.82	5.59	N/A	$129,234$	$23,110
Capital Recovery Factor = 0.0 (There is no capital investment involved with this cost calculation)					

Table I - DEC Economic Analysis for Technically Feasible SO_2 Controls for EU 2

Control Alternative	2023 SO_2 Emissions (tons)[5]	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	182.18	181.27	N/A	$5,374,048	$29,646
No. 1 Fuel Oil (HSHO#1)	182.18	103.77	N/A	$2,398,063	$23,110
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 or HS#1 fuel oil for the fuel oil-fired simple cycle gas turbines at the NPPP with a cost of $29,646/ton and $23,110/ton respectively. Because the economic analysis showed a fuel switch to be cost ineffective, DEC did not evaluate the other three factors included in the four-factor analysis. Therefore, there is no emission limit or control selected for EUs 1 and 2 as a part of the RH four-factor analysis.

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.

[4] Note that this value is not the actual 2023 emissions for EUs 1 and 2, instead it is a conservative estimate of what the actual emissions for 2023 would have been if the source combusted No. 2 fuel oil exclusively instead of No. 1 fuel oil and ULSD. GVEA reported SO_2 emissions of 1.91 tons for EU 1 and 33.30 tons for EU 2 in the 2023 NEI.
[5] See Footnote 4.

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 J.

Table J - 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	0.15 by wt.

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.

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 controlling SO_2 emissions from fuel oil-fired combined cycle gas turbines rated at 25 MW or greater:

Ultra Low Sulfur Diesel (ULSD)
The methods by which combusting ULSD reduces sulfur emissions were discussed in detail in above in the section titled "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.

Light Straight Run Turbine Fuel (LSR)
EU 5 typically combusts LSR when not in startup, which had an average concentration of 0.0023 % S by wt. as reported by GVEA in their 2023 NEI. DEC considers operating LSR a technically feasible control technology for the fuel oil-fired combined cycle gas turbines.

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.

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 K).

Table K - 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.

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.

Department Evaluation of BACT for SO_2 Emissions from the Combined Cycle Gas Turbines
DEC's cost analysis calculated the 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 L.

Table L - 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). Because the economic analysis showed a fuel switch to be cost ineffective, DEC did not evaluate the other three factors included in the four-factor analysis. Therefore, there is no emission limit or control selected for EU 5 as a part of the RH four-factor 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.

DEC 2025 Regional Haze Findings for North Power Plant
DEC finds that it is economically infeasible to switch to ULSD for EUs 1, 2, 5, and 6, or HS#1 fuel oil for EUs 1 and 2 at the North Pole Power Plant. Therefore, no further emissions reductions or emissions controls are selected for the North Pole Power Plant.

b. Golden Valley Electric Association: Healy Power Plant

Introduction and 2022 RH SIP Findings

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 M.

Table M - 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

EU ID	Emissions Unit Name	Emissions Unit Description	Rating/Size	Construction Date
10	Coal Handling System (dust collector #2)	Coal Handling System5	20,000 cfm	1996
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 2022 RH SIP, DEC performed a limited review in place of a full four-factor analysis because the stationary source already had dry sorbent injection (DSI) emissions controls installed on EU 1 and spray dry absorber (SDA) emissions controls installed on EU 2. Additionally, GVEA is under a Consent Decree (CD) with the EPA which required 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 to retire the boiler. The deadline to have SCR installed on EU 1 or to have the EU retired was no later than December 31, 2024. Note that since the 2022 RH SIP, GVEA has decided to not retire EU 1, and has since installed and began operating an SCR unit on EU 1. DEC reviewed the previous six-year period (2014-2019) for which data was currently available to determine the source's SO_2 emissions. Table N 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 N - 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 N, the SO_2 emissions emitted at the Healy Power Plant are from the two coal-fired boilers EUs 1 and 2. Consequently, EUs 1 and 2 were the primary focus during the 2022 RH SIP, which treated SO_2 as the primary pollutant of concern. Condition 44 of Operating Permit AQ0173TVP03 limits EU 2 to an SO_2 emissions rate of no 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 an SO_2 emissions rate of no 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 2019 Guidance Document discusses selecting sources that already have effective emission control technology in place. The 2019 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 2019 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."

Additionally, Section II.B.3.d. of the 2019 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."

In the 2022 RH SIP, DEC chose 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 had already gone through a BART analysis during the first implementation period RH SIP that found additional SO_2 controls on the EU to be cost ineffective and, at the time of the 2022 RH SIP, it was possible that EU 1 would be retired in the future (which ended up not being the case as discussed above). In the case of EU 2, the coal-fired boiler has an emissions limit of 0.10 lb/MMBtu with a requirement to operate SDA on the EU. This emissions limit is half the emissions limit given in the 2019 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 had a less stringent emissions limit of 0.30 lb/MMBtu, the boiler was 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.

In the 2022 RH SIP, DEC concluded that Unit 1 would be considered an effectively controlled source if an enforceable limit of 0.20 lb/MMBtu was selected. While lower emission limits may be achieved with DSI optimization, the selection of 0.20 lb/MMBtu represents significant emissions reductions that could be achieved cost-effectively in the relative near-term that would add greatly to the air quality of the region as well as further assist long term visibility impairment in the park, an issue that has not been shown to have any direct connection to emissions from Unit 1.

The 2010 Regional Haze BART determination[7] for Healy Power Plant's 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 2019 Guidance Document, DEC believed that there have 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 was possible that a re-evaluation of DSI optimization for EU 1 could result in a cost effectiveness finding by DEC. Therefore, in the 2022 RH SIP, DEC required that GVEA either retire EU 1 according to the CD (Option 1), complete a full four-factor analysis for DSI optimization and submit the final four factor analysis to DEC by July 1, 2023 (Option 2), 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 (Option 3). This finding is summarized below in Table O.

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[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/.

Table O - 2022 RH SIP 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

2025 RH Updated Cost Analysis

To fulfill its obligations outlined in the 2022 SIP, as discussed above, GVEA submitted a four-factor analysis for optimizing DSI on June 30, 2023, with the conclusion that their DSI system could not achieve an SO_2 emissions rate lower than EU 1's current emissions limit of 0.30 lb/MMBtu through increased sorbent injection rates alone.

In this updated 2025 cost analysis, to calculate if DSI optimization could be considered cost effective, DEC chose to analyze recent BACT determinations made for SO_2 emissions controls from the 2024 Amendments to the FNSB NAA SIP, Appendix III.D.7.07.[8] In the BACT analyses for the FNSB NAA SIP, DSI was shown to be the most cost effective SO_2 emissions control technology available. Therefore, that is the only emissions control technology that was compared to Healy Power Plant's EU 1. Table P below shows the Department's 2024 DSI cost calculations for the coal-fired boilers located at Fort Wainwright, the Chena Power Plant, and the UAF Campus.

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[8] The FNSB NAA SIP Appendix III.D.7.07 can be found at https://dec.alaska.gov/air/anpms/sip/2024-fbks-pm2-5-serious-sip-amends/.

Table P - DEC Economic Analysis for Technically Feasible SO2 Controls in the 2024 Amendments to the FNSB NAA SIP[8]

Source	Total Rated Capacity (MMBtu/hr)	Uncontrolled PTE (tpy)	Emission Reduction (tpy)	Control Efficiency (%)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Fort Wainwright	1,380	1,470.0	1369.0	93	28,424,000	9,082,000	6,636
UAF (Tri-Mer)	295.6	129.5	103.6	80	3,668,667	4,223,707	40,778
UAF (BACT, Inc.)	295.6	129.5	90.6	70	14,411,039	3,203,706	35,349
Chena Power Plant	497	639.5	607.6	95	43,809,891	8,122,262	13,368
Average	617	592.1	548.7	92	22,578,399	6,157,919	24,033
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)							

In addition to the direct comparison shown in Table P above, DEC also used some of the costs and emissions reductions information from the FNSB NAA SIP and extrapolated the data for a comparison to Healy Power Plant's EU 1, as can be seen below in Table Q. Of the three sources with coal-fired boilers that were analyzed in the FNSB NAA SIP, only the UAF Campus's EU 113, rated at 295.6 MMBtu/hr, and the Chena Power Plant's EUs 4 through 7, rated at 485.1 MMBtu/hr (combined), were brought forward for comparison with Healy Power Plant's EU 1, which is rated at 327 MMBtu/hr. Fort Wainwright's EUs 1 through 6 have a combined rating of 1,380 MMBtu/hr, which is approximately four times the heat input of Healy Power Plant's EU 1.

For the analysis shown in Table Q below, DEC included the total capital investment and total cost data for DSI from the Chena Power Plant and UAF Campus from Table P above and included a row that averages the three. Additionally, DEC used the original control efficiencies from these source's economic analyses, which includes a higher emissions reduction percentage for both of UAF Campus's DSI analyses. DEC had lowered the baseline emissions rate in our BACT analysis for UAF Campus's EU 113 and therefore reduced the previous control efficiencies in order to keep the controlled emission factors the same as the vendor quotes provided to DEC. Additionally, DEC used the 245.4 tons of SO_2 emissions that GVEA reported for Healy Power Plant's EU 1 in the 2023 NEI for the analysis.

Table Q - DEC Economic Analysis for Technically Feasible SO_2 Controls in the 2024 Amendments to the FNSB NAA SIP Compared to Healy Power Plant's EU 1[8]

Source	2023 Emissions (tpy)	Emission Reduction (tpy)	Control Efficiency (%)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
UAF (Tri-Mer)	245.4	220.9	90	3,668,667	4,223,707	19,124
UAF (BACT, Inc.)	245.4	208.6	85	14,411,039	3,203,706	15,359
Chena Power Plant	245.4	233.2	95	43,809,891	8,122,262	34,836

Source	2023 Emissions (tpy)	Emission Reduction (tpy)	Control Efficiency (%)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Average	245.4	220.9	90	20,629,866	5,183,225	23,467
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)						

As can be seen from Table Q above, the projected costs per ton of installing a new state-of-the-art DSI system capable of achieving 85 to 95% SO_2 emissions reductions on Healy Power Plant's EU 1 are in the range of 15 to 35 thousand dollars per ton of pollutant removed. It is possible that because Healy Power Plant's EU 1 already operates with an older DSI system, that the costs would not be as high as they likely already incur some of the same costs associated with this analysis. However, it is also possible that because Healy Power Plant's EU 1 already operates a DSI system, they would not be able to achieve SO_2 emissions reductions in the range of 85% to 95%. Therefore, in this updated 2025 cost analysis, DEC concludes that it would not be cost effective to optimize the DSI system on Healy's EU 1 to require a lower emissions rate.

DEC's 2025 Regional Haze Findings for Healy Power Plant

DEC finds that it is cost ineffective to upgrade the DSI control system on Healy Power Plant's coal-fired boiler EU 1 to lower the SO_2 emissions rate. Healy Power Plant's coal-fired boiler EU 2 is already considered "effectively controlled" under the 2019 Guidance Document with a requirement to operate EU 2 with flue gas desulfurization and a 0.1 lb/MMBtu SO_2 limit.[9] Therefore, no further emissions reductions or emissions controls are selected for the Healy Power Plant for the updated 2025 source review.

[9] Condition 44 of Operating Permit AQ0173TVP03 limits EU 2 to an SO_2 emissions rate of not more than 0.10 lb/MMBtu.

c. Aurora Energy, LLC: Chena Power Plant

Introduction and 2022 RH SIP Findings
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 R and Table S.

Table R - 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 S - 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

For the 2022 RH SIP analysis for the Chena Power Plant, DEC relied upon findings contained in the FNSB NAA SIP that resulted in the 2022 RH SIP determination summarized below in Table T. However, the SO_2 BACT requirements contained in the 2019/2020 FNSB NAA SIP were withdrawn by DEC on September 25, 2023. An updated BACT analysis was included with the submittal of the 2024 FNSB SIP Amendment,[10] which contained a major source precursor demonstration for SO_2 emissions. Therefore, for the updated 2025 source review, DEC has relied upon additional BACT information for SO_2 emissions controls that was included as part of the 2024 FNSB SIP Amendment.[10]

Table T - 2022 RH SIP 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

2024 FNSB NAA SIP Amendment BACT Analysis
Section II.B.3.f. of the 2019 Guidance Document discusses selecting sources that have recently undergone emission control technology review. The 2019 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, 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."

The 2024 FNSB SIP Amendment[11] includes an SO_2 BACT analysis completed by DEC for Chena Power Plant's coal-fired boilers under Part 2 of Appendix III.D.7.07. This analysis concluded that due to space constraints at the Chena Power Plant, it would not be technically feasible to install wet flue gas desulfurization (WFGD), circulating dry scrubbers (CDS), or spray dry absorbers (SDA) on coal-fired boilers. Therefore, dry sorbent injection (DSI) was advanced as the only possible control option for the coal-fired boilers. DEC's economic analysis for DSI is shown below in Table U.

Table U - DEC 2024 FNSB NAA SIP BACT Analysis for Chena Power Plant

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry Sorbent Injection	639.5	607.6	43,809,891	8,122,262	13,368
Capital Recovery Factor = 0.0931 of total capital investment (CRF = i(1+i) n / ((1+i) n -1) [CCM Section 1, Chapter 2, page 22] with an interest rate of 8.5% for a 30-year life cycle)					

[10] DEC's 2024 FNSB NAA SIP Amendment: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-2024-amendment-serious-sip/.
[11] DEC's 2024 FNSB NAA SIP Amendment: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-2024-amendment-serious-sip/.

As can be seen in Table U above, DEC concluded that the average cost per ton of SO_2 removal would be $13,368. Additionally, this BACT calculation for the FNSB NAA SIP was performed with the source's PTE used as the baseline emissions rate as opposed to actual emissions which are used for four-factor analyses in RH. If DEC updated this calculation with the 228.6 tons of actual SO_2 emissions emitted from the Chena Power Plant in 2023, this $13,368 value would more than double. Therefore, DEC concludes that it would be too expensive to install DSI on the coal-fired boilers at the Chena Power Plant for the updated 2025 review.

DEC 2025 Regional Haze Findings for Chena Power Plant

DEC finds that it is technically infeasible to install WFGD, CDS, or SDA based on space constraints, and it is not cost effective to install DSI on the coal-fired boilers at the Chena Power Plant. Therefore, no further emissions reductions or emissions controls are selected for the Chena Power Plant in the updated 2025 source review.

d. US Air Force: Eielson Air Force Base

Introduction and 2022 RH SIP Findings

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 V.

Table V - 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
16	Auxiliary Heating Plant II Boiler #2	--TBD; Not Installed--	98 MMBtu/hr	TBD

EU ID	Emission Unit Name	Emission Unit Description	Rating/Size	Install Date
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

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
EU ID	**Emission Unit Name**	**Emission Unit Description**	**Rating/Size**	**Install Date**
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
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
EU ID	**Emission Unit Name**	**Emission Unit Description**	**Rating/Size**	**Install Date**
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
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
EU ID	**Emission Unit Name**	**Emission Unit Description**	**Rating/Size**	**Install Date**
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
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
EU ID	**Emission Unit Name**	**Emission Unit Description**	**Rating/Size**	**Install Date**
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 Note: 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 2022 RH SIP, DEC looked back over the previous six-year period (2014-2019) for which data was available to determine Eielson AFB's SO_2 emissions. Table WX 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 during this window) are contained in Table W as a footnote. As can be seen, Table W shows that the majority of SO_2 emissions emitted from Eielson AFB are from the coal-fired boilers and, consequently, those were the only EUs that were carried forward for analysis.

Table W - 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.

In the 2022 RH SIP, DEC previously made the finding that the newer coal-fired boilers, EUs 5a and 6a, are already considered "effectively controlled" for SO_2 emissions under the 2019 Guidance Document with dry sorbent injection (DSI) and an existing emissions limit of 0.2 lb/MMBtu, and the older, uncontrolled, coal-fired boilers EUs 1 through 4 would either need to be retired by December 31, 2024, or the USAF would need to submit a four-factor analysis for SO_2 controls by July 1, 2023. The USAF chose not to retire EUs 1 through 4 and instead submitted a four-factor analysis on June 29, 2023, that analyzed wet flue gas desulfurization (Wet FGD), spray dry absorber (SDA), and DSI. The USAF and DEC four-factor analyses for the coal-fired boilers EUs 1 through 4 are contained in the following sections.

SO_2 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.

Cost of Compliance for the Coal-Fired Boilers (EUs 1 through 4)

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 USAF four-factor analysis submitted on June 29, 2023 to complete the cost of compliance analysis. In addition, DEC used information included in previous BACT determinations found in the RACT, BACT, & LAER Clearinghouse (RBLC) database; internet research; and BACT analyses submitted to DEC for the FNSB NAA SIP.

The RBLC was searched for all determinations in the last 10 years under the process code 11.110 Coal Combustion in Industrial Size Boilers and Furnaces. The search results for the coal-fired boilers are summarized in Table X.

Table X - RBLC Summary of SO_2 Controls for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flue Gas Desulfurization / Scrubber / Spray Dryer	10	0.06 – 0.12
Limestone Injection	10	0.055 – 0.114
Low Sulfur Coal	4	0.06 – 1.2

RBLC Review

A review of similar units in the RBLC indicates flue gas desulfurization, limestone injection, and low sulfur coal are the principle SO_2 control technologies installed on industrial coal-fired boilers. The lowest SO_2 emission rate in the RBLC is 0.055 lb/MMBtu.

Identification of SO_2 Control Technology for Coal-Fired Boilers

From research, DEC identified the following technologies as available for control of SO_2 emissions from coal-fired boilers:

Wet Scrubbers/Wet Flue Gas Desulfurization (WFGD)

Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

Most WFGD systems use a limestone slurry sorbent which reacts with the SO_2 and falls to the bottom of the absorber tower where it is collected. Wet FGD systems generally have the highest control efficiencies. New wet FGD systems can achieve SO_2 removal of 99% and HCl removal of over 95%. Packed tower wet FGD systems may achieve efficiencies as high as 99.9% for some pollutant-solvent systems.[12] The Department considers flue gas desulfurization with a wet scrubber a technically feasible control technology for the industrial coal-fired boilers.

Spray Dry Absorbers (SDA)

Spray Dry Absorbers are gas absorbers in which a small amount of water is mixed with the sorbent. Lime (CaO) is usually the sorbent used in the spray drying process, but hydrated lime ($Ca(OH)_2$) is also used and can provide greater SO_2 removal. Slurry consisting of lime and recycled solids is atomized/sprayed into the absorber. The SO_2 in the flue gas is absorbed into the slurry and reacts

[12] EPA Air Pollution Control Cost Manual: Section 5 – SO_2 and Acid Gas Controls, Chapter 1, Page 1-9: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

with the lime and fly ash alkali to form calcium salts. The scrubbed gas then passes through a particulate control downstream of the spray drier where additional reactions and SO_2 removal may occur, especially in the filter cake of a fabric filter (baghouse). Spray dryers can achieve SO_2 removal efficiencies up to 95%,[13] depending on the type of coal burned. The Department considers flue gas desulfurization with an SDA system a technically feasible control technology for the industrial coal-fired boilers.

Circulating Dry Scrubbers (CDS)
Similar to other dry flue gas desulfurization systems, the CDS system is located after the air preheater, and byproducts from the system are collected in an integrated fabric filter. Unlike the SDA systems, a CDS system is considered a circulating fluidized bed of hydrated lime reagent to remove SO_2 rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO_2 removal process. In a CDS system, flue gas is treated in a type of Dry Lime FGD system in which the waste gas stream passes through an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. Water sprayed into the absorber cools the flue gas from approximately 300° F at the inlet to the scrubber to approximately 160° F at the outlet of the fabric filter. The hydrated lime absorbs SO_2 from the gas and forms calcium sulfite and calcium sulfate solids. The desulfurized flue gas passing out of the absorber contains solid sorbent mixed with the particulate matter, including reaction products, unreacted hydrated lime, calcium carbonate, and fly ash. The solid sorbent and particulate matter are collected by the fabric filter. CDS can achieve over 98% reduction in SO_2 and other acid gases.[14] The Department considers CDS a technically feasible control technology for the industrial coal-fired boilers.

Dry Sorbent Injection (DSI)
Unlike the three other FGD systems, dry sorbent injection (DSI) is not a stand-alone, add-on air pollution control system but a modification to the combustion unit or ductwork. DSI systems inject a powdered alkaline reagent directly into the flue gas duct ahead of the particle collection device. Where hydrated lime is used as the reagent, the addition of water may be necessary to complete the chemical reaction. These reagents react with the sulfur (and other acid gases) in-flight and on the surfaces of the particle collection device. The products of reaction, unreacted reagent, and fly ash are collected at the bottom of the particle collection device and disposed of through the plants fly ash collection system. Reagents typically utilized in DSI systems include hydrated lime, Trona, and sodium bicarbonate. According to the EPA CCM[15] DSI can achieve SO_2 control efficiencies ranging from 50 to 70% and has been used in power plants, biomass boilers, and industrial applications (e.g., metallurgical industries). However, USAF's four-factor analysis includes a 90% control efficiency for DSI, which is comparable to the removal efficiencies used in DEC's recent BACT analysis for the

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[13] EPA Air Pollution Control Cost Manual: Section 5 – SO_2 and Acid Gas Controls, Chapter 1, Table 1.3: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.
[14] EPA Air Pollution Control Cost Manual: Section 5 – SO_2 and Acid Gas Controls, Chapter 1, Page 1-11: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.
[15] EPA Air Pollution Control Cost Manual: Section 5 – SO_2 and Acid Gas Controls, Chapter 1, Page 1-11: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual.

FNSB NAA SIP. The Department considers DSI to be a technologically feasible control technology for the industrial coal-fired boilers.

Low Sulfur Coal
The USAF purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross as Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a feasible control technology for the industrial coal-fired boilers. Because the Permittee already combusts low sulfur coal, this control option represents the baseline emissions rate, or a 0% emissions control.

Good Combustion Practices (GCPs)
Good combustion practices for coal boilers include operator practices, maintenance knowledge, maintenance practices, adequate stoichiometric (fuel/air) ratio, combustion zone residence time, temperature, turbulence, fuel quality, combustion air distribution, fuel/waste dispersion. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control option for the coal-fired boilers.

Eliminate Technically Infeasible SO_2 Technologies for the Coal-Fired Boilers
None of the aforementioned control technologies were identified as being technically infeasible for the coal-fired boilers.

Rank the Remaining SO_2 Control Technologies for the Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for control of SO_2 emissions from the coal-fired boilers (Table Y):

Table Y - Control Technologies

Control Technology	Control Level[1, 2]
Wet Scrubbers (WFGD)	90% Control
Spray Dry Absorbers (SDA)	90% Control
Circulating Dry Scrubbers (CDS)	90% Control
Dry Sorbent Injection (DSI)	90% Control
Good Combustion Practices (GCPs)	Less than 40% Control
Low Sulfur Coal	0% Control (Baseline)

Table Notes:
1. The Department used the control efficiency provided in the USAF four-factor analysis for WFGD, SDA, and DSI.
2. Control technologies already required at the stationary source, including burning low sulfur coal or those included in the design of the EU are considered 0% control for the purposes of this four-factor analysis.

Evaluate the Most Effective Controls
After identifying the control technologies and/or operating practices available for the coal-fired boilers, eliminating the technically infeasible control technologies and/or operating practices, and ranking the remaining control technologies and/or operating practices based on efficiency for control of SO_2 emissions, the next step is to perform a cost analysis for the remaining control technologies and/or operating practices. Below is the cost analysis provided by USAF, followed by DEC's own cost analysis.

USAF Cost Analysis for SO_2 Emissions Controls from the Coal-Fired Boilers
The USAF provided an economic analysis for the use of WFGD, SDA, and DSI to control SO_2 emissions from the coal-fired boilers at Eielson AFB. The cost analysis used the EPA's cost control workbooks and associated guidance documents for SO_2 pollution control retrofits, April 2023 version.[16] For its analysis, the USAF used: an EU size of 16.7 MW as calculated by the monthly gross megawatt rating at full-load capacity, a usage rating of 50%, and a pre-control SO_2 E.F. of 0.20 lb/MMBtu which equated to uncontrolled SO_2 emissions of 69 to 72 tons per year; removal efficiencies of 90% for WFGD, SDA, and DSI; the default capital recovery factor (CRF) of 0.143 which equates to equipment life of 30 years and an interest rate of 14%, or an equipment life of 15 years and an interest rate of 11.5%; a waste disposal cost of $50/ton; and an operating labor rate of $63 per hour for DSI. Additionally, the USAF used a retrofit factor and location adjustment factor of 2.67 based on the latest Department of Defense Facilities Pricing Guide (Table 4-1 CONUS, of Unified Facilities Criteria 3-701-01, Change 2, dated 2 March 2023), which the USAF used "to better represent Eielson AFB's location, climate, on-site footprint limitations, and the capacity and condition of existing infrastructure and utilities available."

A summary of the USAF analysis for SO_2 controls for EUs 1 through 4 are shown below in Table Z. Note that the cost analysis is for each individual boiler in 2016 dollars.

Table Z - USAF Economic Analysis for Technically Feasible SO_2 Controls for EUs 1 – 4

Control Alternative	SO_2 Emissions (tons)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
WFGD	69	63	58,556,841	10,217,000	163,368
SDA	72	65	52,562,000	8,825,000	136,790
DSI	69	62.5	7,877,117	1,779,000	28,446
Capital Recovery Factor (CRF) = 0.143 of total capital investment (CRF = i(1+i) n / ((1+i) n -1) CRF of 0.143 is equivalent to a 30-year equipment life (n) at 14% interest (i)					

The USAF analysis also noted that the 2023 EPA retrofit spreadsheet uses 2016 dollars as the default value and so they included a correction to 2022 dollars and a plus or minus 30% cost estimate. These changes increased the cost effectiveness value for DSI, the most cost effective to $32,446 per ton of SO_2 removed. The USAF concludes that the economic analysis indicates the level

[16] The April 2023 and April 2024 version of the EPA Retrofit Cost Tool can be found on EPA's website: https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.

of SO_2 reduction does not justify the use of any SO_2 control for the coal-fired boilers based on the high implementation costs.

DEC Cost Analysis for SO_2 Emissions Controls from the Coal-Fired Boilers
The Department revised the USAF economic analysis with EPA's April 2024 Retrofit Cost Tool spreadsheet[16] which uses 2024 dollars for WFGD and SDA and uses 2021 dollars for DSI. The Department performed two separate analyses to get a range of possible cost outcomes for the installation of SO_2 controls. For the high-cost estimate, the Department left the USAF inputs unchanged with the exception of increasing the usage capacity to 52% for WFGD and DSI to bring pre-control SO_2 emissions to 72 TPY, which matches the highest emissions from one of the coal-fired boilers in the 2023 NEI report. For the low-cost estimate, in addition to updating the April 2024 EPA Retrofit Tool and changing the usage factor, DEC also used the following default inputs to the EPA Retrofit Tool: a retrofit factor of 1.0; a control efficiency of 95% for WFGD and SDA, and 98% for DSI; a waste disposal cost of $30 per ton; and an operating labor rate of $60 per hour. In addition, in order to ensure a conservative low-cost estimate, DEC also changed the CRF to 0.0867, which represents the current bank prime interest rate of 7.75 percent[17] and a 30-year equipment life.

A summary of the DEC's analyses for SO_2 controls for EUs 1 through 4 are shown below in Table AA for the higher cost estimate and Table BB for the lower cost estimate. Note that both cost analyses are for each individual boiler.

Table AA - DEC Economic Analysis for Technically Feasible SO_2 Controls for EUs 1 – 4

Control Alternative	2023 SO_2 Emissions (tons)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
WFGD	72.3	65.0	86,517,746	14,324,000	220,229
SDA	71.7	64.5	77,640,000	12,507,000	193,863
DSI	72.3	65.0	7,877,117	1,794,000	27,582
Capital Recovery Factor (CRF) = 0.143 of total capital investment (CRF = i(1+i) n / ((1+i) n -1) CRF of 0.143 is equivalent to a 30-year equipment life (n) at 14% interest (i)					

Table BB - Department Economic Analysis for Technically Feasible SO_2 Controls for EUs 1 through 4

Control Alternative	2023 SO_2 Emissions (tons)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
WFGD	72.3	68.7	32,403,358	4,760,000	69,332
SDA	71.7	68.1	29,080,000	3,923,000	57,607
DSI	72.3	70.8	3,174,763	861,000	12,157

[17] Bank prime interest rates from the Federal Reserve: https://www.federalreserve.gov/releases/h15/.

Capital Recovery Factor (CRF) = 0.0632 of total capital investment (CRF = i(1+i) n / ((1+i) n -1) CRF of 0.0867 is equivalent to a 30-year equipment life (n) at 7.75% interest (i)

DEC acknowledges that EPA's cost control workbooks published in April of 2023 and 2024, which were used for the analyses above, were designed for boilers that are larger than those found at Eielson AFB. Therefore, DEC also compared these costs to the SO_2 control costs recently published in the FNSB NAA SIP Appendix III.D.7.07[18] for Fort Wainwright. The coal-fired boilers at Fort Wainwright are similar sized units to those at Eielson AFB and both sets were installed in the 1950s. Table 5-3 from the 10.21.24 Fort Wainwright BACT Determination document is included below as Table CC.

Table CC - Department Economic Analysis for Technically Feasible SO_2 Controls at Fort Wainwright

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WFGD - Caustic	101	1369	110,262,000	18,832,000	13,755
WFGD - limestone	101	1369	126,374,000	19,474,000	14,224
Spray-Dry Adsorption	176	1293	166,101,000	22,812,000	17,638
CDS	176	1293	196,447,000	27,096,000	20,950
Dry Sorbent Injection	101	1369	28,424,000	9,082,000	6,636
Capital Recovery Factor = 0.0931 (8.5% interest rate for a 30-year equipment life)					

DEC notes that the BACT analysis for Fort Wainwright showed that the lowest cost per ton control was DSI with a 93% SO_2 removal rate, an SO_2 removal value of 1,369 tons per year, and with 1,470 tons of uncontrolled emissions (the sum of the Potential to Emit and the Emission Reduction columns). Meanwhile, the four-factor analysis for DSI at Eielson AFB was calculated with a conservative 98% SO_2 removal rate and 72.3 tons of uncontrolled emissions. DEC notes that EUs 1 through 4 at Eielson AFB had 212.3 tons of SO_2 emissions combined in 2023, which is approximately an order of magnitude less than the value used for the BACT analysis on the coal-boilers at Fort Wainwright that showed a cost per ton value of $6,636. Therefore, DEC concludes that with such a substantial reduction in the numerator value of the cost per ton equation resulting from using actual emissions in the four-factor analysis vs potential emissions in the BACT analysis, the actual cost per ton for DSI at Eielson AFB is likely closer to the $12,157 to $27,582 value calculated in Table AA and Table BB, compared to the $6,636 value in Table CC.

DEC's cost of compliance economic analysis indicates the level of SO_2 reduction does not justify the use of add on SO_2 controls for Eielson EUs 1 through 4 with an estimated cost of between $12,157 to $27,582 per ton of emission removed for DSI, the least expensive option. The Department notes that an economic analysis for CDS was not performed but recent cost analyses

[18] The FNSB NAA SIP Appendix III.D.7.07 can be found at https://dec.alaska.gov/air/anpms/sip/2024-fbks-pm2-5-serious-sip-amends/.

performed for coal-fired boilers in the FNSB NA SIP showed that CDS costs fall in between DSI and WFGD. Therefore, there is no emission limit or control selected for EUs 1 through 4 as a part of the updated 2025 source review.

DEC 2025 Regional Haze Findings for Eielson Air Force Base

DEC finds that it is cost ineffective to install any SO_2 controls on Eielson AFB's coal-fired boilers EUs 1 through 4. Eielson AFB's coal-fired boilers EUs 5A and 6A are already considered "effectively controlled" under the 2019 Guidance Document with flue gas desulfurization, plus 0.2 lb/MMBtu SO_2 limit.[19] Therefore, no further emissions reductions or emissions controls are selected for the Eielson Air Force Base for the updated 2025 source review.

[19] 0.20 lb/MMBtu SO_2 limit is required under NSPS Subpart Db and is contained in Condition 54 of Operating Permit AQ0264TVP02 Rev. 4.

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

Introduction and 2022 RH SIP Findings

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 DD and Table EE.

Table DD - 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 EE - 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

EU ID	Description of EU	Rating/Size		Location
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
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

For the 2022 RH SIP analysis for Fort Wainwright, DEC relied upon findings contained in the FNSB NAA SIP that resulted in the 2022 RH SIP determination summarized below in Table FF. However, the SO_2 BACT requirements contained in the 2019/2020 FNSB NAA SIP were withdrawn by DEC on September 25, 2023. An updated BACT analysis was included with the submittal of the 2024 FNSB SIP Amendment,[20] which contained a major source precursor demonstration for SO_2 emissions. Therefore, DEC has relied upon additional BACT information for SO_2 emissions controls that was included as part of the FNSB SIP Amendment.[20]

Table FF - 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

[20] DEC's 2024 FNSB NAA SIP Amendment: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-2024-amendment-serious-sip/.

* 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/.

2024 FNSB NAA SIP Amendment BACT Analysis

Section II.B.3.f. of the 2019 Guidance Document discusses selecting sources that have recently undergone emission control technology review. The 2019 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."

The 2024 FNSB SIP Amendment[21] includes an SO_2 BACT analysis completed by DEC for Fort Wainwright's coal-fired boilers under Part 3 of Appendix III.D.7.07. DEC's SO_2 BACT analysis for Fort Wainwright covered the following control technologies: WFGD (caustic and limestone), SDA, CDS, and DSI. This SO_2 BACT analysis concluded that DSI was the only cost-effective control technology and, therefore, the Department at the time advanced DSI as the only possible cost-effective control option for Fort Wainwright's six coal-fired boilers. DEC's economic analysis for DSI is shown below in Table GG.

Table GG - DEC 2024 FNSB NAA SIP BACT Analysis for Fort Wainwright

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WFGD - Caustic	101	1369	110,262,000	18,832,000	13,755
WFGD - limestone	101	1369	126,374,000	19,474,000	14,224
Spray-Dry Adsorption	176	1293	166,101,000	22,812,000	17,638
CDS	176	1293	196,447,000	27,096,000	20,950
Dry Sorbent Injection	101	1369	28,424,000	9,082,000	6,636
Capital Recovery Factor = 0.0931 of total capital investment (CRF = i(1+i) n / ((1+i) n -1) [CCM Section 1, Chapter 2, page 22] with an interest rate of 8.5% for a 30-year life cycle)					

As can be seen in Table GG above, DEC concluded that the average cost per ton of SO_2 removal would be $6,636. However, this BACT analysis was performed with the source's PTE used as the baseline emissions rate as opposed to the source's actual emissions which are used for four-factor analyses in RH. If DEC updated this calculation to use the source's actual emissions, 397.9 tons of actual SO_2 emissions emitted from the Chena Power Plant in 2023, instead of the 1,470 tons per

[21] DEC's 2024 FNSB NAA SIP Amendment: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-2024-amendment-serious-sip/.

year originally used for this analysis, the $6,636 cost effectiveness value shown above in Table GG would more than triple. Therefore, DEC concludes that it would be too expensive to install DSI on the coal-fired boilers at the Fort Wainwright Power Plant for the updated 2025 source review.

DEC Regional Haze Findings for Fort Wainwright CHPP

DEC finds that it is economically infeasible to install WFGD, CDS, SDA, or DSI on the coal-fired boils at the Fort Wainwright Power Plant. As the analysis shows, for the purpose of the updated 2025 source review, these SO_2 emissions controls are not cost-effective. Therefore, no further emissions reductions or emissions controls are selected for the Fort Wainwright Power Plant for the updated 2025 source review.

Enclosure 2: Alaska's Class I Areas Visibility

Enclosure 2: Alaska Class I Areas Visibility

Many of the most significant impacts on Alaska's visibility are uncontrollable sources unique to the state. Visibility degradation contributors such as Alaska-specific vegetation fueling wildfires, episodic volcanic events, oceanic dimethyl sulfide, and international pollution including natural occurrences and emissions from passing international marine vessels are all factors that do not typically affect other Class I areas. Despite these additional impairments, Alaska's Class I areas have some of the greatest visibility and require the least improvement to achieve their 2064 Endpoint Goals under the Regional Haze Rule.

The report titled "2064 Endpoint Updated October 2023[1]" lists the Baselines and the 2064 Endpoint Goals for 113 IMPROVE monitoring stations across the United States. Of the reported stations, the baselines for Alaska's stations located in Denali National Park (DENA1 and TRCR1) and Tuxedni National Wildlife Refuge (KPBO1) are the closest to their respective 2064 Endpoint Goals. Less than three deciviews separate the two points at each station. Note an official baseline for KPBO1 has not yet been provided by EPA and only the 2064 Endpoint Goal is included in the report. However, DEC estimated KPBO1's baseline by averaging the first three years of average annual MID results, the same methodology used to calculate TRCR1 and SIME1's Baselines. The assumed KPBO1 Baseline was used to compare to the other station's data.

Table 1. Baseline and Endpoint Visibility in Deciviews

Class I Area	**Denali National Park**	**Denali National Park**	**Tuxedni National Wildlife Refuge[1]**	**Tuxedni National Wildlife Refuge[2]**	**Simeonof National Wildlife Refuge**
IMPROVE Station	**DENA1**	**TRCR1**	**TUXE1**	**KPBO1**	**SIME1**
Baseline	7.08475	9.11354	10.46850	11.46634	13.66870
2064 Endpoint - Unadjusted[3]	4.72274	6.35727	6.96201	8.76500	8.50625
Difference between Baseline and Endpoint	2.36201	2.75627	3.50649	2.70134	5.16246

Table Notes:

1. TUXE1 stopped collecting data in December 2014 and was replaced by KPBO1.
2. KPBO1 replaced TUXE1 with the first full year of data collected being 2016. A baseline for the station has not been officially determined by EPA. Instead, DEC estimated the baseline by averaging the first three years of annual averages, the same technique used to determine the Baseline for TUXE1, TRCR1, and SIME1.
3. The 2064 End Point Goal or the natural visibility conditions is reported in the IMPROVE data reports called "URP Glidepath – M.I.D" report or the reported in the spreadsheet entitled 2064 Endpoint Updated October.
   https://views.cira.colostate.edu/fed/Express/AqrvTools.aspx#Visibility
   http://vista.cira.colostate.edu/Improve/rhr-summary-data/

[1] Federal Land Manager Environmental Database-Interagency Monitoring of Protected Visual Environments. (October 2023). *2064 Endpoint Updated October 2023.* http://vista.cira.colostate.edu/Improve/rhr-summary-data/. (Accessed 9/11/2025)

The visibility in Alaska's Class I areas is even closer to the 2064 Endpoint Goals than Table 1 above reflects. The methodology and calculations used to designate emissions as either natural or anthropogenic do not have a mechanism to account for Alaska's unique uncontrollable emission sources impacting visibility. These emissions are mischaracterized as controllable anthropogenic and inflate the annual average visibility degradation values, making it impossible for Alaska to achieve the 2064 Endpoint Goals. This error is best illustrated with the data collected by the IMPROVE station representing Simeonof National Wildlife Refuge (Simeonof) designated as SIME1. The SIME1 station is located 60 miles northwest of Simeonof in Sand Point, a community of approximately 600 people on Popof Island in the Aleutian Chain. Simeonof is the farthest Class I area from Alaska's largest emission sources, the site is over 400 miles from the oil and gas operations in Cook Inlet and over 700 miles from the coal-fired power plants operating in the Fairbanks North Star Borough. The only industrial sources close to the station are a small, seasonally operated fish processing plant, and a small diesel generating facility. Yet, as shown in the table above, the station's Baseline and 2064 Endpoint Goal are almost double that of DENA1, the station closest to all the state's biggest coal-fired boilers.

Alaska is heavily impacted by both natural and anthropogenic emissions generated in the Russian Far East and Siberia, East Asia, Canada, and Europe. Emissions from passing international marine vessels impact Simeonof more than any of the other Class I areas. A gap in coverage leaves Simeonof outside of the North American Emission Control Area (ECA) established by the International Maritime Organization as part of the MARPOL convention. The ECA implemented a sulfur standard in 2015 limiting fuel oil burned in marine vessels to a maximum sulfur concentration of 0.5% in designated areas, a significant reduction from the previous limit of 3.5%. However, although the treaty limiting sulfur concentration for the North America ECA protects the shoreline for the rest of the United States, coverage extends to only a small portion of Alaska's coastline including the Inside Passage and the Gulf of Alaska. The Aleutian Islands, Western Alaska, and Northern Alaska are not included and many international vessels operating in these areas continue to burn heavy fuel oil high in sulfur.

Due to limited resources, Alaska is unable to conduct studies to quantify impacts from international emissions to properly categorize them as uncontrollable. Instead, to support Alaska, Hawaii, Puerto Rico, and the Virgin Islands in developing their Second RH Implementation Plan, EPA conducted hemispheric CMAQ modeling to estimate sulfate contributions from international anthropogenic emissions and commercial marine vessels. Based on the results, the report proposed an adjusted 2064 Endpoint and glidepath at each of the Class I areas by adding an estimate of the visibility impact from international anthropogenic sources to natural visibility conditions. The modeling and methodologies used by EPA to calculate the adjusted Endpoints are described in more detail in the report entitled, "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling for Hawaii, Virgin Islands, and Alaska".

Table 2 provides the Baseline for each of Alaska's IMPROVE stations and provides both the Unadjusted and Adjusted 2064 End Points based on the modeling results. By adding the uncontrollable international sulfate emissions into the End Points, a more accurate comparison of the annual average visibility to the glidepath is possible. As shown, the differences between each station's Baseline and End Point decrease significantly to around 1.5 deciviews at DENA1, TRCR1, and KPBO1 and to less than one deciview at SIME1.

Table 2. Baseline and Adjusted Endpoint Visibility in Deciviews

Class I Area	Denali National Park	Denali National Park	Tuxedni National Wildlife Refuge[1]	Tuxedni National Wildlife Refuge[2]	Simeonof National Wildlife Refuge
IMPROVE Station	**DENA1**	**TRCR1**	**TUXE1**	**KPBO1**	**SIME1**
Baseline	7.08475	9.11354	10.46850	11.46634	13.66870
2064 Endpoint - Unadjusted[3]	4.72274	6.35727	6.96201	8.76500	8.50625
2064 Endpoint - Adjusted[4]	5.60	7.55	9.92	9.92	12.86
Difference between Baseline and Endpoint - Adjusted	1.48475	1.56354	0.54850	1.54634	0.80870

Table Notes:

1. TUXE1 stopped collecting data in December 2014 and was replaced by KPBO1.
2. KPBO1 replaced TUXE1 with the first full year of data collected being 2016. A baseline for the station has not been officially determined by EPA. Instead, DEC estimated the baseline by averaging the first three years of annual averages, the same technique used to determine the Baseline for TUXE1, TRCR1, and SIME1.
3. The 2064 End Point Goal or the natural visibility conditions is reported in the IMPROVE data reports called "URP Glidepath – M.I.D" report or the reported in the spreadsheet entitled 2064 Endpoint Updated October.
   https://views.cira.colostate.edu/fed/Express/AqrvTools.aspx#Visibility
   http://vista.cira.colostate.edu/Improve/rhr-summary-data/
4. Adjusted 2064 Endpoint values provided in Table 3-3 of the report entitled, "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling for Hawaii, Virgin Islands, and Alaska". Both TUXE1 and KPOB1 stations were given the same adjusted Endpoint. However, DEC contends that due to the significant change in geographical location and emission source exposure, KPBO1 should be treated as a new site and the data set stand alone.

EPA's modeling efforts also included a zero-out of U.S. anthropogenic emissions for a 2028 visibility projection at each Class I area. The zero-out U.S. anthropogenic emission simulations exclude any anthropogenic emission sources located in the U.S. or territories to provide visibility conditions caused by international anthropogenic emissions and natural sources that are beyond the control of states preparing the RH SIP. This included Class 1 and 2 commercial marine vessels but not Class 3 vessels. CMAQ model setup and all other inputs (i.e., meteorological fields, initial concentrations, and boundary concentrations) are unchanged from the 2016 base year simulation.

Figure 1 below displays the original glidepath as a blue line for each Class I area in Alaska and the adjusted glidepath as a yellow line. The unadjusted projected 2028 MID value is depicted with a solid black circle while the U.S. zero out 2028 forecast is depicted as a solid green circle. As depicted in the figures, modeling indicates that even after excluding all anthropogenic emissions, visibility at Alaska's Class I areas remains above the glidepath at all four IMPROVE stations. In fact, the difference between the 2028 unadjusted forecast and the 2028 zero-out MID is negligible and even undiscernible at Simeonof.

Figure 1. Visibility Glidepaths and 2028 Forecasts in Deciviews at Each Alaska IMPROVE Station

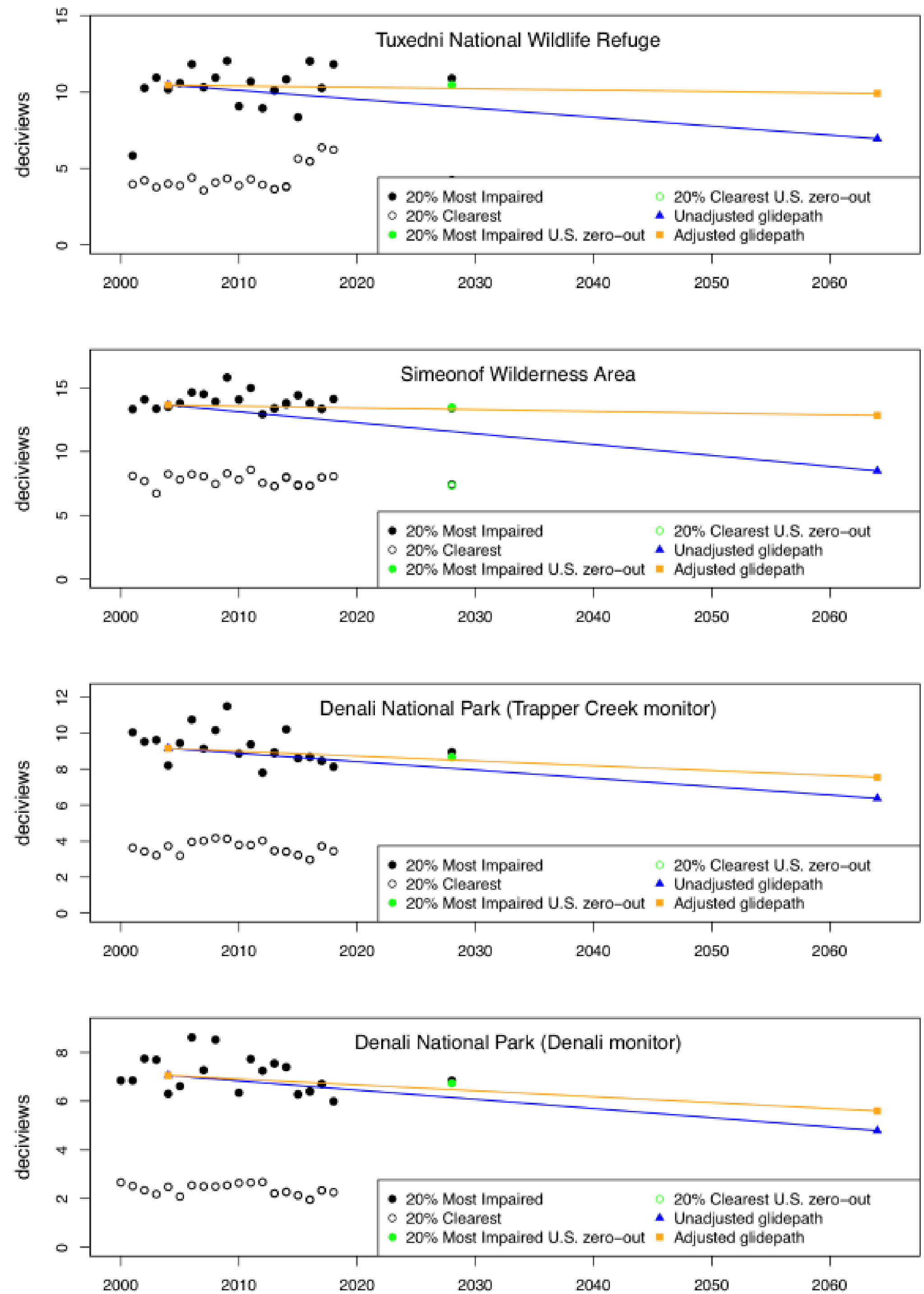

Figure Source: Technical Support Document for EPA's Updated 2028 Regional Haze Modeling for Hawaii, Virgin Islands, and Alaska, Figure 3.9-2. August 2021.

The results of EPA's modeling effort demonstrate that Alaska's Class I areas are already achieving natural visibility conditions. It also confirms that the methodology used to identify uncontrollable and natural sources of visibility impairment is insufficient to properly categorize sources unique to Alaska.

Even after accounting for the international anthropogenic emissions in the 2064 Endpoint and removing all U.S. anthropogenic sources to estimate the 2028 MID point, visibility forecasts remain above the glidepath at all four stations. The difference between Baseline and the 2064 Endpoint Goals can therefore be attributed to natural sources of impairment like Alaska-specific vegetation fueling wildfires, episodic volcanic events, and oceanic dimethyl sulfide.

The study further indicates that imposing additional emission restrictions on industrial sources such as the coal-fired boilers at the Golden Valley Electric Association Healy Power Plant or Eielson Air Force Base will not result in decreased visibility impairment at Denali National Park.