ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

18 AAC 50 AIR QUALITY CONTROL

Response to Comments on May 14, 2019, Proposed Regulations:

November 19, 2019

Table of Contents

Introduction

This document provides the Alaska Department of Environmental Conservation's (ADEC) response to public comments received regarding the May 14, 2019, draft regulations pertaining to regulation changes relating to fine particulate matter (PM2.5) including new and revised air quality controls and a new State Implementation Plan comprised of 15 sections covering monitoring, modeling, control measures, emission inventory, attainment demonstration and episode plan, which are intended to meet federal requirements for the Serious PM2.5 nonattainment area within the Fairbanks North Star Borough (FNSB).

The details describing the proposed regulation changes were presented in ADEC's public notice dated May 14, 2019. ADEC received emailed comments, hand written comments at ADEC's open house, oral testimony at ADEC's public hearings, and comments submitted via the Air Quality Division's online comment system.

This document responds to individual comments from the Environmental Protection Agency (EPA) and aggregated comments from the public. For each section of the proposed regulations and for the State Implementation Plan (SIP), the document summarizes the comments received and provides ADEC's response. The public comments received and ADEC's responses on the Best Available Control Technology determinations for each of the industrial stationary sources are set out by individual facility following the summary of the "Comments Other Than EPA Comments."

Opportunities for Public Comment

The public notice dated May 14, 2019, provided information on the opportunities for the public to submit comments. The deadline to submit comments was July 26, 2019 at 5:00 p.m. This provided a 73 day period for the public to review the proposal and submit comments.

Opportunities to submit written comments included submitting electronic comments using the Air Quality Division's online comment form, submitting electronic comments via email, submitting written comments via facsimile, and submitting written comments via email.

The Division provided an opportunity for individuals to submit oral comments at a daytime public hearing and an evening public hearing held in Fairbanks on June 26, 2019. The hearings provided the opportunity for the public to submit oral comments.

Comments from the Environmental Protection Agency

Emissions Inventory

EPA Comment (1):

Base Year 2013. Consistent with what was provided for the moderate area attainment plan, condensable and filterable emissions data are required to be provided separately, where available. Where condensable emissions data are not available separately, specifically note that they are included in the total number. 40 CFR 51.1008(b)(l) & (a)(l)(iv) (Improve)

Response:

In response to EPA's comment ADEC updated the SIP Inventory Appendix tables to display separate filterable vs. condensable PM emission estimates for the 2013 Base Year inventory. These were provided at the individual Source Classification Code (SCC) level and, consistent with the Moderate Area plan, they also identified those sources/sectors for which each component is available (or for which both components are included in the reported PM total).

EPA Comment (2):

Attainment Projected Inventory. As with the base year emission inventory, the attainment projected inventory requires inclusion of separate filterable and condensable emissions data in the summary and support materials. The year of the attainment projected inventory must be the most expeditious year for which projected emissions show modeled PM2.5 concentrations below the level of the National Ambient Air Quality Standards (NAAQS). Accordingly, the SIP must indicate how the selected attainment year was as expeditious as possible and provide all relevant sector-by-sector growth rates through the selected attainment year. 40 CFR 51.1008(b)(2) & (a)(2) (Improve)

Response:

As explained in response to the previous EPA comment, ADEC updated reported emissions for the attainment projected inventory to provide separate estimates of filterable vs. condensable PM emissions, where available. ADEC further explained the rationale behind projecting attainment as expeditiously as possible and provided sector-specific growth rates for the attainment projected inventory.

Modeling

EPA Comment (3):

Modeling. Please include in your submission to EPA all input and output files associated with the modeling for the base year and attainment projected inventories. Where you rely on information already provided to EPA as part of the moderate area plan, please identify those elements. 40 CFR part 51, appendix V, section 2.2 (Improve)

Response:

ADEC will transmit the modeling input and output files and emissions inventory on a data drive when the final adopted Serious SIP is submitted to EPA. Previously for the moderate area plan, a data drive including modeling files and meteorological files (Weather Research and Forecast (WRF) model) were sent to U.S. EPA Region 10 when the final moderate area SIP was submitted.

Precursor Demonstration

EPA Comment (4):

SO_2 Precursor Analysis. We understand that there is interest in a precursor demonstration for SO_2, but that there are information limitations that restrict the ability to make such a demonstration. On page 43 of the modeling chapter, Vol. II:III.D.7.8, it is stated that no sensitivity-based precursor demonstration was pursued for SO_2 as a result of limitations on scientific information to support such a demonstration and therefore precursor emissions are considered significant. We agree with the State's conclusion that SO_2 precursor emissions are considered significant for the reasons provided by the State. Until the informational and technological limitations are addressed, SO_2 must be assessed for Best Available Control Measures (BACM) and Best Available Control Technology (BACT) for all source categories. See 40 CFR 51.1010(a). We summarize some of the informational and technological limitations here.

Model development for SO_2 and sulfate formation is an active area of research and we are hopeful to have improved modeling tools in the coming years. Beginning on page 47 of the modeling chapter and continuing on page 58, an SO_2 analysis is presented that attempts to quantify the point source contribution to total observed sulfate. EPA is concerned that, while the SO_2 analysis presented is not intended as a proposed precursor demonstration, the analysis makes several unsupported assumptions that we view as serious flaws in the methodology. First, it is assumed without supporting information that sulfur oxidation occurs uniformly throughout the airshed and on all sources of SO_2 at equal rates. Second, it is assumed that currently modeled sulfate impacting the monitors is an unbiased and accurate quantification of primary sulfate impacts at the monitors, essentially assuming the modeling is perfect in regard to primary sulfate impacts but does not provide a model performance evaluation that supports this assumption.

Given the technical limitations of current modeling tools to correctly model secondary sulfate in winter environments such as Fairbanks and the flaws in the presented SO_2 analysis, we agree that it does not make sense to pursue a sensitivity-based precursor demonstration at this time. (Improve)

Response:

ADEC appreciates EPA's feedback on this issue. ADEC made no changes to the SIP to assert a sensitivity-based precursor demonstration for SO_2 as it is not scientifically possible to pursue a sensitivity based precursor demonstration at this time.

Attainment Demonstration

EPA Comment (5):

Attainment Demonstration. Under Clean Air Act (CAA) Section 189, a Serious area attainment plan is required to show attainment by December 2019 or include a request for an attainment date extension. Based on the current air quality data, attainment by the 2019 attainment date is impossible given that the annual 98th percentile PM2.5 concentrations in 2017 and 2018 were too elevated to allow for a three-year Design Value that meets the 24-hour PM2.5 standard of 35 $\mu g/m^3$. Although the proposed plan includes a request to extend the attainment date to 2024 (the outermost date allowed by the CAA), it does not appear to fully meet all the CAA Section 188(e) requirements for an extension. Therefore, EPA will likely not be able to approve an extension to the attainment date. However, because CAA Section 189(b)(1)(A) requires that the state demonstrate attainment by December 31, 2019 or request an attainment date extension under CAA Section 188(e) this element must be retained for completeness.

If the Fairbanks area does not meet the relevant attainment date, CAA section 189(d) requires the state to develop a new 5% attainment plan within one year. This new 5% plan must meet the requirements of CAA Sections 172-173 and 189(d) and 40 C.F.R. part 51, subpart Z, including demonstrating attainment as expeditiously as practicable, and providing for an annual reduction in PM2.5 emissions within the area of not less than 5% of the amount of such emissions as reported in the most recent emissions inventory. We recommend that the attainment demonstration for this future plan establish a realistic attainment date and provide the supporting documentation on how the selected attainment date is the most expeditious date possible. (Retain/ Improve)

Response:

ADEC appreciates EPA's comment and understands that because the Serious nonattainment area will not attain the standard by December 2019 and the extension request contained within the Serious SIP is likely not approvable, the state must develop a new 5% attainment plan within one year. ADEC is already initiating efforts to develop the 5% plan.

Best Available Control Measure (BACM) – General

EPA Comment (6):

Enforcement Authority. We support the effort to grant ADEC administrative enforcement authority in a limited capacity for the Fairbanks nonattainment area. This will provide for the ability to more directly enforce its curtailment authority and expedite improvement in the air quality for all residents within the nonattainment area. (Improve)

Response:

The local stakeholder group expressed in their recommendations support for ADEC to receive authority to use administrative penalties in the FNSB nonattainment area and ADEC agrees that such authority could result in efficiencies for the program. However, the power to grant this authority lies with the Alaska State Legislature through the passage of a bill. At this time, no legislation on this topic has been introduced for consideration. As a result, ADEC will continue to use its current civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area. The ADEC Air Quality Division has relied successfully on its current authorities in implementing the CAA programs for decades.

EPA Comment (7):

Adequate Funding. We recommend the State of Alaska to continue to provide funding for implementation activities in the Fairbanks nonattainment area. The state has committed to strong measures through both the Moderate and Serious area attainment plans, but these measures can only be successful if they are funded and supported by the regulating agency. We commend the effort taken by the state in 2018/19 to take the lead on implementing the curtailment program. Success will continue to depend on the state's involvement in that program and the close coordination with the local governments. (Improve)

Response:

ADEC is committed to funding and implementing the measures included in the Serious SIP. The ADEC budget is determined annually by the Alaska State Legislature and the Division relies on a mix of federal and state general fund revenue to operate this program. The Division of Air Quality is prioritizing work to ensure efficient and effective implementation of all committed measures and will continue to do so.

EPA Comment (8):

Selected Control Measures. The BACM Analysis, Control Strategies Chapter, and draft Regulations show that ADEC has made a conscientious effort to select a suite of controls on the residential wood burning source category. The CAA requires that all measures deemed BACM must be implemented, and it provides that the obligation to impose BACM on all source categories is generally independent of attainment needs. CAA Section 189(b)(1)(B) & 40 CFR

51.1010(a). Adoption and implementation of these measures will be critical to the approvability of the control strategy element of the plan. See Table 1. (Retain)

Response:

ADEC appreciates EPA's comment and restatement of the requirements for BACM. Selected control measures as finalized following public comment are included in the Serious SIP and will be subject to future EPA actions on the SIP with respect to approvability.

EPA Comment (9):

Economic Infeasibility. A number of measures were dismissed as being economically infeasible. Please provide the supporting documentation and spreadsheets used to assess BACM economic feasibility as identified in Table 9 page 140 of the BACM analysis in Appendix III.D.7.07. (Improve)

Response:

All measures identified as being economically infeasible will have supporting spreadsheets and documentation submitted to EPA as part of the final adopted Serious SIP submittal package.

EPA Comment (10):

Information Collection. A limited number of proposed regulations require certain sources to provide information to ADEC, rather than implementing controls on certain source categories. Collecting facility-specific information is an important step in the BACM selection process but does not in and of itself constitute BACM. See 40 CFR 51.1010(a)(4). We suggest completing the information collection process, analyzing identified controls, and adopting feasible controls or demonstrating infeasibility for each of these source categories. (Improve)

Response:

In the process of preparing the BACM analysis for the Fairbanks PM2.5 nonattainment area, ADEC requested information of previously uncontrolled commercial emission sources, including: charbroilers, incinerators, and oil burners. Recognizing the request of information on their facilities, equipment and operations is the first step in regulatory development, essentially all of the facilities and related organizations contacted chose to remain silent and did not respond to repeated information requests. EPA's comment about the need to complete the information collection process is appropriate as the imposition of control measures must be predicated on the size, equipment rating and operations in place for each facility. To address the information shortfall, ADEC has drafted regulations (18 AAC 50.078(c)) mandating the submission of specific categories of information from each source and they are referenced in both the draft SIP and the draft BACM analysis report. Once implemented, facilities will have no more than two months to respond. Committed measures for each source/facility will be identified and included in future SIP revisions. It is ADEC's intent to formally request the information as soon as there is an effective date for the amendments to 18 AAC 50.078(c). ADEC will review that information, analyze technical and cost feasibility, propose potential regulations for public review, and include any applicable final regulations as part of the initial 5% plan that will be due in 2020.

Best Available Control Measure – Fuels

EPA Comment (11):

Ultra-Low Sulfur Diesel (ULSD).

To support approvability of the BACM portion of the proposed plan, we recommend ADEC provide further consideration of ULSD as BACM for heating oil in the Fairbanks nonattainment area. As stated under the Precursor Demonstration section, above, SO_2 is a PM2.5 precursor and, therefore, measures to control SO_2 emissions must be evaluated and implemented. The proposed ADEC regulation requiring the switch from #2 Diesel (2,566 ppm) to #1 Diesel (896 ppm) will reduce fuel sulfur content in Fairbanks. Because this measure has been found to be cost effective, it will be required for purposes of meeting the requirement to implement BACM. 40 CFR 51.1010(a).

However, the ADEC BACM analysis (Measure 51, page 92-93 of the BACM analysis in Appendix III.D.7.07) of this measure identifies that ULSD (15 ppm) is technologically feasible nationwide and has been widely available in Alaska since 2010. As the future emissions inventories show an increase in sulfur and with increased conversion to liquid fuel home heating devices, it will be important to address reduced sulfur in two contributing source sectors, industrial and residential boilers.

The ADEC analysis also points to an economic assessment (Residential Fuel Expenditure Assessment of a Transition to Ultra-Low Sulfur and High Sulfur No. 1 Heating Oil for the Fairbanks PM2.5 Serious Nonattainment Area, pdf page 183 in Appendix III.D.7.07) that concludes that ULSD is currently not economically feasible as the cost of switching to ULSD from #2 diesel would be on average $329 per device per season. The BACM analysis (Table 9 on page 140 of the Appendix III.D.7.07) cited a $25,765/ton cost as the basis for economic infeasibility. In your final attainment plan submission to EPA, please provide the supporting spreadsheets and documentation. Understanding how this figure was calculated is particularly important given that, based on the State's own analysis, ULSD was selected as BACT for two point sources and the State's BACM analysis identifies that ULSD is available and in use in Alaska.

While the ADEC economic assessment was a helpful short run analysis based on 18 months of data, we recommend a more defensible assessment that also analyzes a longer run analysis to better understand price differentiation over time. Additionally, the study would benefit from an update to better understand local fuel price elasticity. This is especially true given the nature of the local markets in this area. Finally, the study in the future should utilize existing tools to better understand changes in the market.

If ULSD is found to be economically feasible, the existing Targeted Air Shed grant program could provide an opportunity to provide incentives on the device side to allow for boiler retrofits, upgrades, and/or cleaning to allow for conversion to this cleaner fuel. (Improve)

Response:

ADEC will provide the supporting information with respect to its BACM cost effectiveness analysis for this measure. *The "Best Available Control Measures Analysis for Fairbanks $PM_{2.5}$ Nonattainment Area"* report located in SIP Appendix III.D.7.7 includes a detailed discussion of the cost effectiveness for the shift from Diesel #2 to Diesel#1 or ULSD (Measure 51). The report was revised to address the comments received from EPA and refiners. In summary, those comments addressed:

- Presentation of the impact of regulations on the sulfur emissions from industrial and residential boilers;
- Documentation and spreadsheets supporting the cost per device and cost effectiveness of fuel changes;
- Expansion of the time period analyzed for fuel price differences and related elasticity estimates;
- Assumptions about the transition of JP4 to JP8;
- Assumptions about the Higher Heating Values of heating oils; and
- Assumptions about supply and transportation costs.

The results presented show that changes in fuel use from both measures produce a small increase in direct $PM_{2.5}$ emissions, which moot any consideration of their cost effectiveness. The more important impact of these measures is on SO_2 emissions, a $PM_{2.5}$ precursor pollutant, and the results show that while both measures produce a significant reduction in SO_2, the shift from No. 2 to No. 1 provides a reduction in cost, while the shift from No. 2 to ULSD produces an increase in cost. Thus, the negative cost effectiveness of the shift from No. 2 to No. 1 is more cost effective.

Revisions to the supplier analysis also determined that a switch from Diesel #2 to ULSD would require all fuel oil for space heating be imported by truck or rail into the community at a cost premium as described in the analysis and supporting economic assessment. The shipment of fuel by truck and rail can lead to other environmental impacts as accidents involving tanker trucks and railcars periodically occur resulting in releases of fuel to the environment that require clean up and remediation. While some ULSD is available in the community for transportation sources and other stationary sources that require it, this is a much lower volume of fuel than would be required for all sources in the community. The very large change in fuel supply required to achieve this shift further supports a finding that the switch from Diesel #2 to ULSD is cost ineffective.

With respect to the additional ADEC/UAF economic analysis of switching from Diesel #2 to ULSD or Diesel #1, the report titled, "*Residential Fuel Expenditure Assessment of a Transition to Ultra-Low Sulfur and High Sulfur No. 1 Heating Oil for the Fairbanks PM-2.5 Serious Nonattainment Area*," looks at incremental price differentials between fuel types in the Fairbanks area. Based on EPA's past comments to the preliminary draft, the authors updated the report to extend their analysis from 12 months to 18 months of data. The UAF and ADEC economists also conducted a separate analysis related to estimation of FNSB home heating price elasticities. That report is titled, "*Estimating FNSB Home Heating Elasticities of Demand Using the Proportionally-Calibrated Almost Ideal Demand System (PCAIDS) Model: Postcard Data Analysis*", and is included in SIP Appendix III.D.7.6. It took significant time for the UAF and ADEC economists to develop the reports that were included in support of the Serious SIP; it is not possible for ADEC to conduct further economic analyses with the limited data available in a timely manner for this SIP.

Best Available Control Measure – Woodsmoke

EPA Comment (12):

Key Source Sector. Woodsmoke control is essential to the Fairbanks attainment strategy, and we are pleased with the selected suite of measures in this action. The selection and implementation of these measures will be key towards meeting CAA requirements and reducing emissions in the nonattainment area. See Table 1. (Retain)

Response:

ADEC appreciates EPA's comment and concurs with the importance of woodsmoke controls in addressing the air pollution concerns with the nonattainment area. All the selected suite of measures has been retained and included in the submitted SIP, although some have been slightly refined based on public comment and legal review.

EPA Comment (13):

Prohibition of Solid Fuel Devices in New Home Construction (Measure 8). This measure exists in the Bay Area Air Quality Management District as noted in ADEC's BACM assessment. Under the existing Fairbanks woodstove changeout/conversion program, one option has been to remove woodstoves completely from an existing residence and provide backup generators as the secondary heating system. Based on the existing measure in the Bay Area and current practices in the Fairbanks nonattainment area it appears to be technologically feasible to design new homes in the nonattainment area that have dual heating systems that are not reliant on wood heating. We recommend this measure be further considered so that growth and development within the nonattainment area does not increase emissions. Additional information to further substantiate the claim that the measure is technologically or economically infeasible must be provided. (Improve)

Response:

ADEC often hears from FNSB residents who have significant concerns regarding the need for non-electric backup heating systems in their homes. Given the subarctic climate and periodic power failures, these individuals have real safety concerns for themselves and their families as well as concerns about damage to their property. These concerns and expressed needs for reliable backup heat are likely very different in the FNSB nonattainment area than in the San Francisco Bay Area where the BACM prohibition originates. However, we agree that based on the Borough's woodstove changeout/conversion program that it is technically feasible to design a new home with adequate backup heating systems that do not rely on solid fuel heating appliances. Even though it may be technically feasible in certain situations, without widespread availability to natural gas there are limited technologies to provide backup heat to address the safety concerns. While voluntary programs are in place, only 12 emergency power back up systems have been installed through the Borough's program. With the limited number of actual installations, ADEC is cautiously optimistic that the emergency power back up systems will become a proven technology, but at this point the limited installations do not demonstrate that this technology is feasible in every situation. Due to the importance of these systems to ensure citizen safety in an arctic climate, it is not prudent to exclude an entire sector of proven residential heating technology that many citizens rely on for an immediate safety concern. An economic analysis was conducted with a cost effectiveness of $24,845 per ton of PM2.5 reduction, and this measure has been deemed to be economically infeasible. The BACM Analysis document, in the Appendix to Section III.D.7.7 has been updated to reflect this conclusion.

EPA Comment (14):

Emergency Episode Plan. The Fairbanks Curtailment program as described in the Emergency Episode plan will be critical to achieving and maintaining emissions reductions in the nonattainment area during periods of poor air quality. The plan would benefit from work to clarify the program and its implementation. This can be done by providing additional details in regulation that define each curtailment stage, list reproducible steps to call a burn ban, identify what devices are applicable, and outline the requirements and processes associated with granting each type of Stage I waiver and NOASH (No Other Adequate Source of Heat). We appreciate the effort that has gone into developing the Stage I Waiver and NOASH tables. We recommend developing regulations to identify the process by which the implementing agency will review and grant the Stage I Waiver or NOASH, and the process which the applicants must follow to apply for a Stage I Waiver or NOASH. Any implementing regulations should include sufficient detail to ensure that waiver and NOASH criteria are unambiguous for each criterion in the first column in the respective Tables in the Emergency Episode Section 7.12. These areas for improved clarity include: documentation needed for established need, procedure for how device emission rating and age will be confirmed, documentation needed for installation certification, process for tracking renewals and upgrades, process for identifying chimney sweep/device maintenance/frequency requirements and documentation need for confirmation, documentation needed to confirm dry wood and at what frequency, inspections frequency and confirmation requirements, and records on compliance with opacity requirements during the curtailment. (Improve/Retain)

Response:

ADEC appreciates EPA's comments on the importance of clarity for the public in the description of the local emergency episode plan, but respectfully disagrees with EPA's comments associated with bringing the details of the emergency episode plan and waiver program into state regulation. The SIP is brought into regulation through the adoption by reference of the State Air Quality Control Plan in 18 AAC 50.030. The regulations and SIP episode plan in combination establish the basic authority and parameters for calling curtailments and issuing waivers. The Episode Plan clearly identifies that curtailments will be called after review of all meteorological data and when it is determined that calling a curtailment will result in protection of the health based standard. Details of the waiver program and the various application requirements may be found online on the DEC web site. EPA's recommendation to include all these details in regulation would not necessarily result in more clarity. It could result in potential over regulation or an inability to make necessary adjustments resulting from experience gained as the Division implements the Emergency Episode Plan.

EPA Comment (15):

Implementation Dates/Delayed Effective Dates. For measures and regulations with delayed implementation dates, please include discussion as to the rationale for why the dates are delayed and why the selected dates are the most expeditious possible. We were not able to find this information in the submittal. 40 CFR 51.1011(b)(5) (Improve)

Response:

BACM Measure #51 and 18 AAC 50.078(b) address an areawide fuel oil switch from #2 heating oil to #1 heating oil with a starting date of September 1, 2022. ADEC had originally proposed a July 1, 2020 start date, but received a number of adverse comments from the public and industry associated with the proposed implementation of this measure in 2020. The switch from #2 heating oil to #1 heating oil will require an infrastructure change on the part of local refineries and local fuel distribution systems and has an estimated economic impact that individuals indicated would drive more residents to using wood/solid fuel heat. With the timing of the final Serious SIP being released in the middle of the 2019/2020 heating system it would be technically infeasible to require the local refineries and fuel distributors to make this change in the middle of a heating system and given the adverse comments, a starting date prior to the 2022/2023 heating season was chosen to provide time for the local refineries and residents to prepare and budget for a switch to #1 fuel oil. The slightly longer timeframe for implementation also provides the opportunity for residents to consider and take advantage of the expanded natural gas service planned for the community in the coming few years. Further discussion and response to comments from the public and industry are provided later in this document.

BACM Measures 31 and 32 and 18 AAC 50.076(d) & (j) require commercial wood sellers to ensure that wood being sold has a moisture content less than 20%, effective October 1, 2021. Lacking infrastructure, such as kiln capacity sufficient to dry a season's worth of wood, the only technically feasible method of drying commercially available cordwood to less than 20% moisture content is to air dry the wood. A study of the time required to dry wood in Fairbanks[1] found that a minimum of six summer months with covered storage is required to dry wood from spring cutting to a moisture level below 20%. However, ADEC regulation 18 AAC 50.076(k) has set the minimum of 9 months drying time, unless confirmed, to ensure that the wood is dry given the variation in wood drying with different storage options. The same study determined that wood cut in the fall dries much more slowly and essentially stops drying once the wood becomes frozen. At this time the community lacks adequate storage space to dry the wood required to fill the commercial market. The summer of 2020 would be used by the commercial wood sellers to secure the space and construct structures to air dry the wood. Cord wood harvested during the spring of 2021 could then be stored and dried by October 2021 which is the most expeditious schedule that the commercial wood industry can follow to meet the requirements of this rule. Further discussion on refinements made to the final regulation in response to comments from the public are provided later in this document.

BACM Measures 16, 48, & 49 and 18 AAC 50.077(*l*) require date certain removal of all EPA uncertified devices, all outdoor hydronic heaters (except outdoor pellet fueled hydronic heaters), and all existing coal-fired heating devices to be removed or replaced by December 31, 2024. The current device inventory estimates that approximately 13,418 wood burning appliances are in the nonattainment area with 2,553 of those appliances estimated to be uncertified. Estimates also show approximately 481 coal fired residential heaters in the nonattainment area for a total of 3,034 appliances that need to be removed. Current funding for the Borough's wood stove change out program shows that, including the 2018 Targeted Air Shed grant award, the total projected change outs achievable from 2019 through 2024 are 1,290. The date of 2024 provides residents adequate time to participate in the wood stove change out program in order to comply with the regulation without overwhelming the Borough program resources. Further discussion and response to comments from the public are provided later in this document.

<u>EPA Comment (16):</u>

Measure 42. We support adoption of this measure, which requires a set burn down period when ADEC declares an air emergency episode in the nonattainment area. We note that, as written, 18 AAC 50.075(e)(3) does not mandate the burn down. We recommend revising 18 AAC 50.075(e) to clearly mandate the burn down. Alternatively, please indicate what provisions of

[1] Wood Storage Best Practices in Fairbanks, Alaska, conducted by the Cold Climate Housing Research Center (CCHRC), June 27,2011.

the 18 AAC Chapter 50 or the State Air Quality Control Plan, including Volume II: III.D.7 .12 Fairbanks Emergency Episode Plan, mandate that owners and operators of solid fuel heating devices in the nonattainment area comply with the conditions in ADEC's notices of a Fairbanks North Star Borough Air Quality Alert or Episode. Please include a discussion of ADEC's process for ensuring that mandatory requirements will be included in each Air Quality Alert. We also recommend that ADEC revise the State Air Quality Control Plan, Volume II: III.D.7.12 Fairbanks Emergency Episode Plan to match the revisions to 18 AAC 50.075(e). (Improve)

Response:

The Serious SIP is a chapter of the State Air Quality Control Plan that is adopted by reference into state regulation at 18 AAC 50.030. As a result, the Fairbanks Emergency Episode Plan as described in Section III.D.7.12 is enforceable by ADEC. This section of the SIP outlines for the public the specifics related to episodic control requirements within the nonattainment area along with the process ADEC uses for announcing episodes. ADEC revised Section III.D.7.12 to incorporate the language added to 18 AAC 50.075(e) to ensure that the burn down requirements are clearly identified within the local Episode Plan. ADEC also uses a fixed episode announcement template that will have the burn down language included so that every curtailment called within the nonattainment area will contain the burn down language.

EPA Comment (17):

Measure 54. The BACM analysis for CARB Vehicle standards does not appear to be in the Appendix. Please include it in the final submission. (Improve)

Response:

Under Section 177 of the federal Clean Air Act, states that choose to adopt vehicle standards that are more stringent than the federal standards for new vehicles can only adopt California’s vehicle emission standards. To date 14 states have opted-in to California’s vehicle emissions standards. The most current version of California’s Low Emission Vehicle (LEV) III regulations limit greenhouse gases and traditional tailpipe pollutants (HC, CO, NOx and PM). These regulations were modified by California in 2015 to align the California and federal Tier 3 motor vehicle emission standards. The federal Tier 3 rules were finalized in 2014 by the U.S. EPA and reduced tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium-duty passenger vehicles and allowable emissions from heavy-duty vehicles. The California LEV III and federal Tier 3 regulations are consistent from model year 2017 through 2024 for particulate emissions. Starting in 2025, however, the stringency of the LEV III standards will be increased from 3 mg/mi to 1 mg/mi, while the federal Tier 3 standards will remain at 3 mg/mi. Thus, an extremely small reduction in motor vehicle particulate emissions (i.e., 2 mg/mi) will become available in late 2025 and succeeding years.

To put this reduction into perspective 1 million miles of travel by vehicles meeting the more stringent 2025 – 2028 LEV III particulate emission standards would produce a reduction of 4.4 lbs. Several factors must be considered when assessing the benefit of adopting the LEV III standards, including:

An analysis of the most recent Department of Motor Vehicle (DMV) registrations (April 2018) showed the statewide population of vehicles was 644,312 and a total of 97,600 were registered in Fairbanks. Assuming vehicle ownership is proportional to population, the number of vehicles registered in the nonattainment area is 82,980. Since Alaska would be required to adopt the California Air Resources Board (CARB) vehicle standards on a statewide basis, it means 87% of the light duty passenger cars and light-duty trucks sold each year starting in 2025 would be required to meet the more stringent standards without a supporting mandate.

- Assuming wintertime driving travel is roughly 50 miles per vehicle per day (more than twice the value employed in the Fairbanks travel demand model forecasts), it would take 20,000 vehicles to produce 4.4 lb/day reduction in PM emissions. Assuming the 2 mg/mi reduction applied to the entire vehicle fleet, which it does not because the California and federal emission standards for medium/heavy duty vehicles are equivalent through this period, the total reduction potential within the Fairbanks PM nonattainment area would be on the order of 18 lbs per day (in reality less).

The magnitude of the emission reduction potential must be considered in light of the disproportionate impact on the rest of the Alaska vehicle fleet. The statewide adoption of the CARB LEV III emission standards is not warranted for the Fairbanks $PM_{2.5}$ nonattainment area. The BACM analysis document was modified to reflect this response.

EPA Comment (18):

Petrostar BACM/BACT. ADEC made efforts to evaluate larger area sources as part of the BACM process, including the Petrostar refinery in North Pole. We recommend including this evaluation as part of the final submittal will be necessary for demonstrating that the BACM assessment was properly completed. (Improve)

Response:

ADEC has added to the SIP a summary of its efforts to evaluate Petrostar and the findings that were corroborated by EPA Region 10 staff, that there are no additional control measures available for the type of equipment that Petrostar is using at their North Pole facility.

Best Available Control Technology

EPA Comment (19):

Site Specific Quotes. EPA is unable to provide detailed comments on the BACT analysis in the absence of site-specific quotes for each SO_2 control technology previously identified in EPA comments. Site specific quotes are required in order to provide the cost and technical feasibility information that is needed to assess and select BACT, especially for retrofit applications. In the absence of this information, any control technologies successfully implemented nationwide will be considered technologically and economically feasible. See 40 CFR 51.1010(a)(3), 81 FR 58081- 85.

Response:

ADEC received site specific quotes from several sources for SO_2 controls: Doyon Utility provided a rough order-of-magnitude cost estimate from Black and Veatch for a dry sorbent injection (DSI) system to be installed at Fort Wainwright; Aurora provided an estimate from Stanley Consultants, Inc. for the installation of a DSI system to be installed at the Chena Power Plant; and GVEA provided a technical memo from PDC engineering for the installation of three million gallons of fuel storage at the North Pole Power Plant. For UAF, ADEC calculated the cost effectiveness of installing DSI controls on the dual fuel-fired boiler using the "Dry Sorbent Injection for SO_2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA" which resulted in a cost effectiveness value of $8,269/ton of SO_2 removed, assuming an average retrofit factor of 1.0, a 0.2 lb/MMBtu SO_2 emission rate, and an 80 percent control efficiency.

ADEC finds these control technologies to be considered technologically and economically feasible as Best Available Control Technology for these sources in the Serious nonattainment area for PM2.5.

ADEC also calculated the cost effectiveness for installing wet scrubbers and spray dry absorbers on the coal fired boilers using the spreadsheets prepared by Sargent and Lundy for the US EPA and found the controls would have an adverse economic impact when considering the limited incremental SO_2 reduction beyond what is achievable with DSI, and considering the total capital investment of these control technologies at least twice the cost as compared to installing DSI at these sources based on these calculations.

EPA Comment (20):

Facility and Control Equipment Life. We recommend that the submittal document its assumptions for facility and control equipment life especially where they diverge from current assumptions in the EPA control cost manual (EPA CCM) and other EPA technical support documents. The discussion of proposed shorter lifetimes in the current plan does not contain support information for those lifetimes. We recommend that this evidence include such information as the actual age of currently operating relevant control equipment, and design documents for associated process equipment such as coal-fired boilers. We recommend including all enforceable shutdown agreements or analyses completed that document actual examples where equipment lifetimes were shortened by other conditions such as the arctic environment.

Response:

Section 4 Chapter 2 of the EPA Control Cost Manual (CCM) lists equipment life for SCR as 30 years for power plants and 20 to 25 years for industrial boilers.

The CCM does not have a section for DSI, and the "Dry Sorbent Injection for SO_2/HCL Control Cost Development Methodology" on the EPA's website is silent on DSI equipment life. The only reference to equipment life in Section 5 Chapter 1 of the CCM for SO_2 and Acid Gas Controls is 15-years, used as an estimated equipment life for estimating annual cost on wet scrubbers.

Therefore, ADEC used 15 years for DSI and 20 years for Selective Catalytic Reduction (SCR) based on the age of the existing facilities and taking into account the harsh winter environment which is known to shorten equipment life. Extreme subzero temperatures place a heavy burden upon operating equipment, thereby significantly reducing its life expectancy.

EPA Comment (21):

Control Efficiency. Calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency rate achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. Such technical justification is needed if the facility's analysis includes control efficiency assumptions different from those in the EPA CCM and other EPA technical support documents.

Response:

For the controls identified in the BACT analyses, ADEC used a NOx removal efficiency of 90% for selective catalytic reduction (SCR) with the exception of an 80% reduction used for UAF's dual-fuel fired boiler. The reasoning for the reduced removal efficiency for UAF's boiler is that a 90% reduction in NOx emissions would mean a BACT limit of 0.02 lb/MMBtu but the 2019 CCM states that "*theoretically, SCR systems can be designed for NOx removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu).*"

ADEC identified an SO_2 control efficiency of 80% for dry sorbent injection based on the spreadsheet prepared by Sargent & Lundy LLC for U.S. EPA for un-milled Trona (sodium bicarbonate) with a baghouse.

ADEC identified a 99.7% SO_2 control efficiency for a fuel switch from No. 2 diesel to ULSD based on mass balance calculations.

EPA Comment (22):

Economic Infeasibility. An economic infeasibility determination is a possible outcome of the BACT process. Developing an adequate economic infeasibility assessment to support an approvable BACT determination should include the following:

- We recommend at least two site specific vendor quotes for each control technology.
- We recommend economic infeasibility assessments developed using economic theories include appropriate analysis of potential impacts on relevant markets and products (e.g., price elasticity of demand for fuels).
- Financial information/discussion for the source that, when compared to the cost of the control, helps address the question concerning the economic feasibility of the control technology for the specific source. If such information is considered to be CBI, then there are mechanisms by which that information can be collected and protected from public disclosure.
- EPA-approved control cost effectiveness analysis and economic infeasibility assessment.

Given the technical nature of these analyses, we recommend that an economist or someone with equivalent training or expertise be involved in the development of the economic infeasibility assessment.

Response:

When choosing between two or more technologies, it is reasonable to consider the sizeable capital cost difference between wet scrubbers, Spray Dryer Absorbers (SDA), and Dry Sorbent Injection (DSI), and the relatively small reduction of SO_2 between the control technologies. ADEC determined the control effectiveness of these control options by evaluating actual emissions data from other sources employing similar types of controls, EPA's pollution control fact sheets, and taking into consideration that BACT limits must be achieved at all times. ADEC calculated the cost effectiveness for installing wet scrubbers and SDA on the coal fired boilers and found the cost effectiveness of these controls to have an adverse economic impact when considering the total capital investment costs.

In addition, the harsh arctic climate plays a significant role in escalating total costs. Equipment such as heating, ventilating, air conditioning units, and exhaust fans should not be placed in exposed locations because of the extreme temperature differences to which the equipment would be exposed. Outside air intakes and exhaust outlets require baffles to trap the windblown snow, preventing it from entering into the ductwork or thawing and causing leaks. Construction equipment must be modified to protect it from temperature related failure and to protect the operator from weather extremes.

Building equipment rooms are larger to accommodate more and larger heating equipment (also, exposed rooftop equipment is undesirable due to poor maintenance accessibility during long, cold, dark winters). Often space is needed to house redundant equipment that may be needed to address the dire consequences of an equipment failure.

ADEC notes that it has followed, to the extent possible, the EPA guidance for the use of site specific cost data and economic indicators in making its determination. ADEC no longer employs a staff economist and is unable to conduct further economic analysis in the timeframe available for finalizing the Serious SIP.

EPA Comment (23):

Regulations and Enforceability. To ensure the BACT determinations in the SIP submission are approvable, they need to be practically enforceable. We recommend the final SIP present the BACT requirements in a manner similar to how a source-specific permit would look - by source and unit, with emission limits, monitoring requirements, recordkeeping, reporting, etc. This information will be required for approvability and enforceability.

Response:

The Department added new tables in the beginning of each of the stationary source sections of the SIP Control Strategies chapter that contains a summary of the BACT and SIP findings. These tables layout which controls are specified for each emissions unit (EU) at each stationary source for the different pollutants and their corresponding emission rates. The tables also specify by what date an application is due to the Department to implement these changes into the stationary source’s permits and at what date the Department will issue the permits to ensure enforceability.

EPA Comment (24):

Ultra-Low Sulfur Diesel (ULSD, 15 ppm). ULSD has been selected for some facilities and low sulfur Light Straight Run (LSR, 30 ppm) is already in use at other facilities. ULSD and/or LSR appear to be cost effective in practice and by analysis. To substantiate the decision not to select either of the lower sulfur fuels for other sources and source categories, the analysis must establish that ULSD and LSR are either not cost effective (based on site-specific cost quotes) or technically infeasible for a specific emission unit.

Response:

The Department selected ULSD or low sulfur Light Straight Run (LSR, 50 ppmw) as BACT for all of the liquid-fired EUs at the stationary sources with Title V permits in the nonattainment area with the exception of the Zehnder Facility EUs and emergency generator EU 7 at the North Pole Power Plant. GVEA is taking a stationary source wide

SO_2 limit of less than 70 tpy at the Zehnder Facility. Regarding EU 7 at the North Pole Power Plant, GVEA provided an economic analysis showing a cost effectiveness value of $45,072/ton of SO_2 removed for EU 7, which has an existing potential to emit of 0.01 tpy. The Department did not modify this cost analysis on EU 7 due to the extremely low amount of SO_2 emissions removed from switching to ULSD (0.0099 tpy).

Aurora - Chena Power Plant

EPA Comment (25):

BACT Determination. No source control was selected in the 2019 Serious area plan, however the plan acknowledged that ADEC found DSI to be cost effective in the 2018 preliminary plan. In previous comments, EPA recommended that the identified three higher efficiency technologies be evaluated in the BACT analysis, but site-specific cost information has not been provided. A source-specific quote (preferably two or more for each SO_2 control technology previously identified by EPA) would be needed to assess the appropriate BACT for this facility. A 0.2% sulfur content by weight in coal by 2021 was listed as BACT, however there is only one source of coal in Alaska and this requirement does not appear to reduce the sulfur content in the fuel. In the absence of an approvable economic infeasibility assessment, we would need additional information to understand and document how these constituted BACT level control.

Response:

Regarding the implementation of a 0.2% sulfur content by weight for coal at sources in the nonattainment area, this number has increased to 0.25% due to multiple comments received by the Department on the draft SIP. The Department has moved these requirements for the three stationary sources with coal-fired boilers from the BACT Determination and into the SIP Control Strategies chapter as they were not a part of the BACT decision, but rather an addition to the SIP to prevent backsliding in the future.

EPA Comment (26):

Economic infeasibility. Our review of the affordability assessment of BACT for the Chena Power Plant indicates that the financial documentation provided by Aurora does not provide a comprehensive picture of the incremental costs of installation and operations of potential BACT controls. We recommend that the plan include an economic infeasibility assessment, developed by an economist or someone with equivalent training or expertise, as described in BACT - General section, above, to substantiate the state's conclusion. It would be helpful for that assessment to address a number of factors, including economic viability given the current and projected customer base and recent financials, supporting documentation for cost estimate increases based on potential BACT controls, an assessment of price elasticity of demand, substitution possibilities, etc.

Response:

ADEC has provided all site specific economic analysis information currently available in making its determination of economic infeasibility. ADEC has followed to the extent possible, the EPA guidance for the use of economic indicators in making its determination. ADEC no longer employs a staff economist and is unable to conduct further economic analysis in the timeframe available for finalizing the Serious SIP.

Doyon/Fort Wainwright

EPA Comment (27):

BACT Determination. It appears that DSI is cost effective, as determined in the 2018 preliminary plan, and that site-specific cost information for higher efficiency technologies has not been obtained. A source specific quote (preferably two or more for each SO_2 control technology previously identified by EPA) would be needed to assess the appropriate BACT for this facility. A 0.2% sulfur content by weight in coal by 2021 was listed as BACT, however there is only one source of coal in Alaska and this requirement does not appear to reduce the sulfur content in the fuel. We would need additional information to understand how this constituted a BACT level control.

Response:

Doyon/Fort Wainwright did not provide additional quotes for the control technologies with higher efficiencies than DSI (wet scrubber and spray dry absorber). The Department updated our previous analysis of these two control technologies using the updated uncontrolled emission factor of 0.58 lb/MMBtu to reflect the increased allowance in coal sulfur content of 0.25% set by this SIP. The Department found the cost of implementing these control technologies economically infeasible at $16,356 and $16,748 per ton of SO_2 removed for wet scrubbing and spray dry absorbers, respectively. The Department notes that this cost estimate may actually be low given that the spreadsheet used to calculate these values assumed one boiler of 138 MW as opposed to the six 23 MW boilers that actually exist at Fort Wainwright.

Regarding the implementation of a 0.2% sulfur content by weight for coal at sources in the nonattainment area, this number has increased to 0.25% due to multiple comments received by the Department on the draft SIP. The Department has moved these requirements for the three stationary sources with coal-fired boilers from the BACT Determination and into the SIP Control Strategies chapter as they were not a part of the BACT decision, but rather an addition to the SIP to prevent backsliding in the future.

EPA Comment (28):

Shutdown Agreement. A shutdown agreement could potentially satisfy the BACT requirement or enable ADEC to demonstrate that BACT controls are not feasible based on the remaining useful life of the unit(s). However, in order for a shutdown agreement to impact BACT obligations, the agreement must be embodied in an enforceable order under state law, must include a date certain for source shutdown, and must be received in a timely manner such that it can be considered as part of the overall SIP submission. We recommend that the state also explore the option of incorporating a commitment to adopt specific measures for this source in the SIP submission that meets the requirements of CAA Section 110(k)(4).

Response:

The Department is no longer in discussions with the Army regarding a shutdown agreement for the coal-fired boilers at Fort Wainwright, and this language has been removed from the SIP Control Strategies chapter. The Department is requiring the installation of DSI on the six coal-fired boilers at Fort Wainwright which were determined to be BACT. Doyon Utilities is required to submit a permit application to include DSI on the boilers no later than June 9, 2020, and DSI is to be effective no later than October 1, 2023.

GVEA – Zehnder

EPA Comment (29):

BACT Determination. Under the 2018 preliminary plan, ULSD was selected as BACT. This 2019 plan proposes that the facility revise its emissions limit below the major stationary source limit of 70 tons per year. The CAA and the PM2.5 SIP Requirements Rule requires that all feasible control measures and technologies that meet the BACM (including BACT) criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources. In this situation we recommend that the original ADEC BACT determination published in 2018 be selected for this facility.

Response:

Section 7.7.8.4 of the SIP Control Strategies chapter requires GVEA to submit a permit application by June 9, 2020 to limit potential SO_2 emissions at the Zehnder Facility to less than 70 tpy. This limit will be effective no later than June 9, 2021. At this point, the Zehnder Facility will not be subject to BACT for SO_2, but rather subject to BACM. One of the Department's BACM measures designed to limit SO_2 emissions is contained in 18 AAC 50.078(b), which states, "After September 1, 2022, only fuel oil, containing no more than 1,000 parts per million sulfur, may be sold or purchased for use in fuel oil-fired equipment, including space heating devices. This subsection does not apply to major stationary sources subject to Best Available Control Technology determination or to diesel-fired equipment or vehicles subject to more stringent federal diesel fuel sulfur requirements."

In 2018, the Zehnder Facility released approximately 19 tons of actual SO_2 emissions from combusting both No. 1 and No 2 fuel oil. Approximately 94% of the fuel oil combusted at the Zehnder Facility in 2018 was No. 2 fuel oil listed at 0.387% sulfur, and approximately 6% was No. 1 fuel oil listed at 0.096% sulfur. If the BACM measure was in place requiring the Zehnder Facility to combust No. 1 fuel oil exclusively in 2018, then actual facility wide SO_2 emissions would have been less than 5 tons that year. Therefore, the Department feels that the facility wide SO_2 limit at the Zehnder Facility combined with the

BACM measure requiring the switch to less than 1,000 ppm sulfur in fuel oil will ensure low amounts of sulfur are emitted from this facility.

GVEA – North Pole

EPA Comment (30):

BACT Determination. ULSD (15ppm) was originally selected as BACT in the 2018 preliminary plan, and it has been found to be economically feasible for Doyon/Ft. Wainwright and University of Alaska Fairbanks (UAF) in the 2019 plan. Additionally, Light Straight Run fuel, a low sulfur fuel (30ppm), is currently in use at this facility. The 2019 BACT determination identified switching select units from #2 to #1 on curtailment days and setting a future decision point for selecting lower sulfur fuel. It will be difficult to support an economic infeasibility determination in light of the current information. Additional site-specific cost information or providing an enforceable agreement for a future switch to lower sulfur fuel is necessary to support the assertion that this meets BACT requirements.

Response:

In addition to the switch to No. 1 fuel oil on curtailment days for EUs 1 and 2, the Department updated Section 7.7.8.5 of the SIP Control Strategies chapter to require these EUs switch to ULSD from October 1 through March 31 starting on October 1, 2023. GVEA is required to submit a permit application for this change by June 9, 2022. EUs 5 and 6 currently operate using LSR, which is a low sulfur fuel. The Department performed an economic analysis for switching EUs 5 and 6 to ULSD from LSR and found this economically infeasible at $1,040,822 per ton of SO_2 removed.

University of Alaska - Fairbanks

EPA Comment (31):

Economic Infeasibility. In order for EPA to review ADEC's finding that additional SO_2 controls are economically infeasible, the state or UAF will need to provide an economist developed infeasibility submittal as described in the section BACT - General, above.

Response:

ADEC has provided all site specific economic analysis information currently available in making its determination of economic infeasibility. ADEC has followed to the extent possible, the EPA guidance for the use of economic indicators in making its determination. ADEC no longer employs a staff economist and is unable to conduct further economic analysis in the timeframe available for finalizing the Serious SIP.

EPA Comment (32):

BACT Determination. In the 2018 preliminary plan DSI was selected as BACT. In addition to economic infeasibility, technological infeasibility was also cited in this 2019 plan, which asserts that the facility could not efficiently be retrofitted with a new control technology. However, the conclusion assumes the source must achieve a high-end control efficiency from DSI and that achieving such a control efficiency is not technologically feasible due to the need to inject excess sorbent into the ducting, with the resulting negative impacts. We recommend that the BACT analysis instead evaluate the cost effectiveness of DSI based on the level of control efficiency practicable given the current infrastructure in addition to evaluating the cost effectiveness of retrofitting the ductwork to achieve higher control efficiency via DSI and other SO_2 control technologies.

Response:

The Department did not find the installation of DSI to be technologically infeasible in the BACT Determination or the SIP Control Strategies chapter. The language in the Section 7.7.8.6.4 of the SIP Control Strategies chapter discussing the difficulty of achieving the high level of SO_2 control typically associated with DSI was additional information provided by UAF. However, as stated in Section 7.7.8.6.5 of the SIP Control Strategies chapter, the Department is not requiring DSI be installed on UAF's EU 113 because sufficient evidence has been provided to demonstrate that imposing add-on DSI controls on the dual fuel-fired boiler would cause an adverse economic impact to UAF and is therefore economically infeasible.

The Department notes that according to its calculations, the cost per ton of SO_2 removed using DSI at an 80% and 30% control efficiency is $8,269 and $13,255 per ton, respectively. Both of these values are considered to be cost effective for a BACT Determination in the Serious nonattainment area without the additional financial indicators showing an adverse economic impact to the stationary source.

Reasonable Further Progress (RFP) and Quantitative Milestones (QM)

EPA Comment (33):

Control Measure Implementation Schedule. For each RFP quantitative milestone year, a detailed schedule must be provided describing the implementation, including the percentage of compliance or quantity of completion where applicable (i.e., curtailment compliance, woodstoves changeouts/conversions), of each control measure during each year of the applicable attainment plan as outlined in 40 CFR 51.1012 and 51.1013. This will provide the basis for evaluating RFP as identified in the plan and as reported in the required QM reports. We recommend that RFP be measured in modeled emission reductions and associated with implemented control measures for reporting the QMs. A chart/graph may help illustrate annual progress. (Improve)

Response:

In the final SIP, ADEC expanded on the level of detail reported in the RFP/QM analysis performed for the Draft SIP to include information on implementation/compliance estimated for each analysis year.

EPA Comment (34):

Support Calculations. Please submit the supporting analysis and documentation for how these emissions reductions were calculated for each milestone years. If readily available in the existing package, please provide a reference to that documentation. (Improve)

Response:

In the final SIP, ADEC provided additional discussion in the RFP chapter of the SIP (Section III.D.7.10) and supporting analysis and documentation of these emission reductions in the Appendix III.D.7.10.

EPA Comment (35):

Ammonia. The RFP/QM emissions reductions will also be required for NH3 given that it does not have a precursor demonstration. The document should note that VOCs and NOx are not included as ADEC anticipates submitting approvable precursor demonstrations. Each quantitative milestone year will also be required to include an RFP inventory of on-road mobile source emissions for direct PM and the relevant precursors. (Improve)

Response:

The RFP/QM chapter (Section III.D.7.10) was updated to include ammonia (NH_3) and explain the rationale for not including VOCs and NOx within the RFP evaluation. The RFP chapter was revised to report on-road motor vehicle emissions (and relevant precursors) for each RFP year.

EPA Comment (36):

SO_2 increases. The total nonattainment area SO_2 emission levels increase by 88%, and some categories including jet fuel and non-road mobile sources show much higher increases in SO_2. Please explain the change in SO_2 estimates in Table 7.10-4. (Improve)

Response:

ADEC received updated refiner/supplier information on jet fuel grades and historical volumes through the public review of the Draft SIP. The 2013 Base Year (and 2017 RFP) inventories were revised to reflect this information and the resulting changes in SO_2 emissions are much less significant than reported in the Draft SIP inventories.

EPA Comment (37):

QM Report Due Dates. A functional addition will be to identify the dates by which ADEC is required to submit the QM reports. This will assist with tracking and help to avoid the triggering of contingency measures for failure to submit a report. (Improve)

Response:

QM report dates were added to the RFP/QM section for the SIP (III.D.7.10).

Motor Vehicle Emissions Budgets (MVEB) and Conformity

EPA Comment (38):

As per 40 CFR 93. l 18(e)(4), please include all support documents including MOVES runs documenting the submitted MVEBs. To allow review of the attainment demonstration and RFP MVEBs, please provide the following files:

- RunSpec files for each MOVES run used in developing the MVEBs;
- County Input Databases developed for each MOVES run used to develop the MVEBs; Output databases generated by MOVES after each run used to develop the MVEBs; and any input files or database files modified to represent the engine block heating program. (Improve)

Response:

In its SIP transmittal, ADEC will provide EPA with electronic versions of the MOVES input files used to develop the MVEBs within the SIP along with accompanying documentation describing their contents/modeling years.

EPA Comment (39):

Contingency Measure. The contingency measure in the proposed plan appears to support the continued improvement of heating devices within the nonattainment area by requiring them to meet lower emissions requirements and by requiring removal of older devices while providing sufficient time for the community to prepare and comply with the changes. Consistent with the CAA and EPA's implementing regulations, 18 AAC 50.077(m) must be revised to ensure that the contingency measure is triggered upon the occurrence of any of the determinations listed in 40 CPR 51.1014(a), including "to submit a quantitative milestone report required under §51.1013(b)." Under CAA Section 172(c)(9) and 40 CPR 51.1014(a), the contingency measures need to be implemented to achieve emissions reductions consistent with the overall RPP requirement, which is the need to make annual incremental reduction in emissions in the nonattainment area necessary to achieve attainment. Please identify or supply the information documenting the quantification of emissions reductions associated with this measure with particular emphasis on how the triggering of 18 AAC 50.077(m)(l)(B) will effectuate meaningful annual reductions in PM2.5 emissions consistent with RPP. (Improve/Retain)

Response:

ADEC made revisions to the final regulations to include the requirement to submit a quantitative milestone report. Section 18 AAC 50.077 was reorganized due comments and to meet state legal drafting guidelines. Therefore, the updated contingency measure may now be found in 18 AAC 50.077(n). The quantification of the contingency measure was added to the RFP/QM section of the SIP.

EPA Comment (40):

Table 1. Selected Measures that must be implemented to meet BACM requirements. (As described in the KEY COMMENTS, BACM General, and Wood smoke sections, the measures in Table 1 have been selected as BACM and are necessary for approval of the BACM element of the Serious area attainment plan.). (Retain)

Identified Measures			**Proposed BACM Regulations**
#		**Description**	**Proposed to Adopt as BACM**
2	"'	Prohibit advertising used devices that do not meet emission criteria for new device sales	18 AAC 50.077(k)(5)
3	S28 S31	Require building or other permit	18 AAC 50.077(k)(4)
4	S33	Require confirmation of proper installation by requiring professional installation or on-site inspection	18 AAC 50.077(k)(2)&(3)
5		Register/require industry certification of heating professionals	18 AAC 50.077(k)(2)&(3)
7		Require devices meet stricter emission criteria in high pollution zones.	18 AAC 50.077(c), (d), (e), (f), (g), (h), (i),
13		Submit sale and installation information to Air Program	18 AAC 50.077(d),(d)(3) & (k)(l)
15		Disclosure of devices on property sale	18 AAC 50.077(b),(k)(2) & (m)
16	S17b S18	Require notice and proof of destruction or surrender of removed, uncertified devices (date certain removal of uncertified devices)	18 AAC 50.077(b),(k)(2) & Emergency Episode Plan
17		Require Removal of Uncertified Solid Fuel Burning Devices Upon Sale of Property	18 AAC 50.077(b)
19, 21	S1a,S1c	19 - Require registration of devices to qualify for exemption from curtailments 21- Optional device registration for curtailment exemptions	18 AAC 50.077(k)(1) & Emergency Episode Plan
20		Require renewals with inspection requirements	18 AAC 50.077(k)(1) & Emergency Episode Plan
22	S1a	Require registration of all devices	18 AAC 50.077(k)(1), 18 AAC 50.077(c), (d), (e), (f), (g)
24	S22	Require Permanent Installed Alternative Heating Method in Rental Units	18 AAC 50.077(k)(4)
25	S24	Require detailed application or inspection to verify need for No Other Adequate Source of Heat (NOASH)	Emergency Episode Plan
26		Require inspection of device and installation	18 AAC 50.077(k)(2) & (3)
27	S26,S27	Require annual renewal of waiver	Emergency Episode Plan

28		Set income threshold [for Curtailment Exemption]	Emergency Episode Plan & 18 AAC 50.077(b)
29	S25	Allow only NOASH households to burn during curtailment periods	Emergency Episode Plan
30		Distribution of Curtailment Information at Time of Sale of Wood-Burning Device	18 AAC S0.077(k)(1)
31	S13	Require sale of only dry wood during late summer to end of winter	18 AAC 50.076(j) & 18 AAC 50.078(e)
32		Require dry wood to be clearly labeled to prohibit marketing of non-dry wood as dry wood	18 AAC 50.076(j) & 18 AAC 50.078(e)
40	S25	Single stage curtailment	Emergency Episode Plan
42		Burn down period	18 AAC 50.075(e)(3)
48	S20	Date certain removal of "coal only heater"	18 AAC 50.079(f) 18 AAC 50.077(k)(2)
49	S20	Prohibit use of coal burning heaters	18 AAC 50.079(f)
51	S12	Ultra-low Sulfur Heating Oil	18 AAC 50.078(b)
65		Emissions crossing property lines	18 AAC 50.075(f)(2)
66		Lower curtailment threshold	Emergency Episode Plan
67		Coffee Roasters - Commercial	18 AAC 50.078(d)
68		Charbroilers - Commercial	18 AAC 50.078(d)
69		Incinerators - Commercial	18 AAC 50.078(d)
70		Used Oil Burners	18 AAC 50.078(d)
71		Date certain removal for EPA certified devices over 2.0 g/hr or over 25 years old.	18 AAC 50.077(m)
R4		AII wood stoves must be certified	18 AAC 50.077(b)
R5		Ban new installations - Hydronic Heaters	18 AAC 50.077(c), (d), (e) & (k)(2)
R6		Remove hydronic heaters at time of home sale	18 AAC 50.077(b)
R10		Replace uncertified units at time of sale	18 AAC 50.077(b)
R11	S29	Replace uncertified units at time of significant remodeling	18 AAC 50.077(b)
R12		Replace uncertified stoves in rental units	18 AAC S0.077(b)
R16		Disincentives to sell used stoves	18 AAC 50.077(b), (e), (f) & (k)(2)
	S23	Require catalytic device change out per manufacturer's specifications, with mandatory chimney sweep and device check on annual or biennial basis	Emergency Episode Plan
	S30	Prohibit sales of 5FBAs that don't meet state standards Require all aftermarket controls on 5FBAs to be professionally installed, with exemption for existing devices	18 AAC 50.077(c), (d), (e), (f), (g), (h), (i), (j)
	S32	Require all aftermarket controls on 5FBAs to be professionally installed, with exemption for existing devices	18 AAC 50.077(k)(2)&(3)
	S34	Adopt legislation giving DEC citation authority	FNSB Resolution

Response:

All items in the table remain within either the Serious SIP documents or the regulations. ADEC made some adjustments to specific regulations and citation references due to public comment and legal review. This includes a complete rearrangement of 18 AAC 50.077 to meet state legal drafting guidelines.

General Comments

EPA Comment (41):

Air Quality Improvement

We are encouraged that there is a reduction in PM2.5 concentrations measured at the monitor in North Pole. Since its establishment in 2012 through 2018, the three-year design value at the Hurst Road site has dropped from 139 µg/m^3 (2012-14DV) by over half to 65 µg/m^3 (2016-2018DV). While there are many variables that influence design values, the scale and timing of the observed reduction in PM2.5 concentrations strongly indicate that the wood stove curtailment program (bum bans) and other control measures were effective. The 74 µg/m^3 reduction in 24- hour PM2.5 DV at the Hurst Road site suggests that effective local regulation and targeted community efforts can lead to improvements in air quality that support the attainment of the standard.

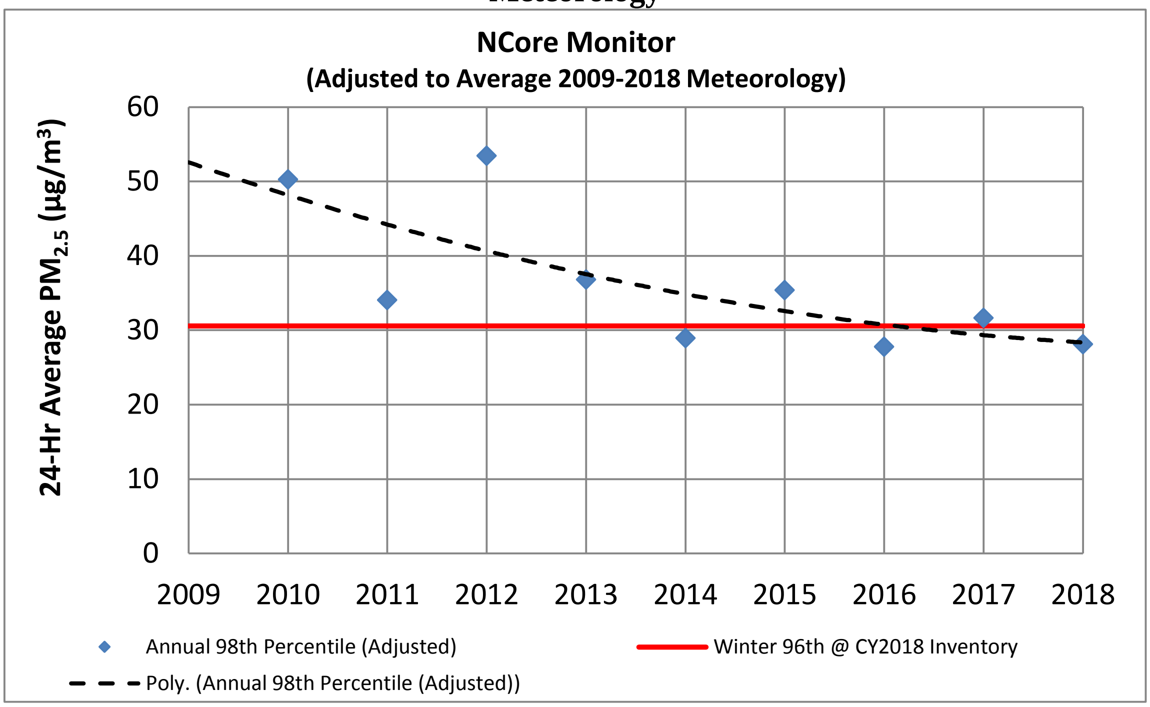
When reviewing the meteorological assessment, we noticed that the PM2.5 concentrations recorded at the NCORE monitor vacillate, as opposed to the uniformly downward trajectory at the Hurst Road site. For instance, the analysis concluded that after adjusting for meteorology, the 98th percentile at the NCORE monitor wavered from 50 µg/m^3 in 2010, 34 µg/m^3 in 2011, 53 µg/m^3 in 2012, and 37 µg /m^3 in 2013. This result would benefit from further investigation because the efficacy of control strategies would not be expected to vary in this manner from year to year. If other reasons play a role in this interannual variability, then it is important to account for them in a conclusion about what has caused the recent string of years below the 35 µg/m^3 standard. The EPA remains committed to providing technical assistance to conduct this additional analysis. (Improve/Retain)

Response:

This comment is motivated by Figure 1, which has been excerpted from the SIP document; the black, dashed trendline has been superimposed on the chart to support the following discussion. There is a consistent downward trend in the annual 98th percentile of concentrations at NCore, with some evidence that the rate of improvement has slowed in recent years. The year-to-year values fluctuate noticeably around the downward trend, being larger in the early years, particularly 2011 and 2012, and smaller but still present since 2013.

While there may be multiple factors behind the fluctuations, the largest is the fact that the 98th percentile was determined from 1-in-3 day sampling historically. That is, FRM measurements were made every third day giving an annual sample of 365 / 3 ~ 122 measurements. On this basis, the 98th percentile is determined from a sample, rather than an enumeration of the entire year, and will be influenced by random chance. Since the 98th percentile is at the end of the distribution, the emissions curve is very steep. Therefore, it can make a large difference whether an FRM measurement was taken on the highest day of an inversion episode or was taken on the next or the subsequent days. The 1-in-3 sampling is unbiased for determining the 98th percentile over the long-run, but its result can deviate up or down in any given year. The State has changed its practice and now takes FRM measurements on a daily basis in Fairbanks and North Pole, which eliminates the influence of sampling going forward.

Figure 1: Fairbanks: Trends in Peak 24-Hour PM2.5 Values Adjusted to Constant Meteorology



EPA Comment (42):

Nonattainment New Source Review (NNSR)
The NNSR program is a required element for the Serious area SIP.ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and EPA has proposed approval of this element in June 2019. (Retain)

Response:

ADEC has noted in Section III.D.7.7.9 (DEC Stationary Source Control), EPA's final approval, effective September 30, 2019, of the state regulation revisions to 18 AAC 50 Article 3 that address nonattainment new source review for the Serious nonattainment area.

EPA Comment (43):

Air Quality Episodes
We appreciate the effort that ADEC has already taken to confirm that the 2008 episodes are appropriate for use in the Serious area plan. We recommend including additional explanation about the selection of the 2008 episodes including the efforts underwent to assess and confirm their appropriateness for this Serious area plan. It would also be helpful to inform the community through the plan narrative about the proactive efforts underway by the state to update the episodes for future planning. (Improve/Retain)

Response:

ADEC added additional explanation to Section III.D.7.3.3 (Summary of Design Day/Episode Selection for the Fairbanks PM2.5 Nonattainment Area) to address this comment.

EPA Comment (44):

Ammonia Precursor Demonstration. The Modeling chapter correctly identifies that there is no ammonia precursor demonstration. However, the RFP chapter incorrectly states that ammonia has a precursor demonstration.

Response:

There was no ammonia precursor demonstration and this has been corrected in the RFP chapter (Section III.D.7.10).

EPA Comment (45):

NOx Precursor Demonstration. We recommend that this section only include the primary table from which conclusions are based and move the remaining support tables to the appendix.

Note that the May 2019 final EPA Precursor Demonstration Guidance includes a revised air quality impact threshold for the PM2.5 24-hour standard, below which a precursor's impact to ambient PM2.5 levels can be considered insignificant. The revised air quality impact threshold is $1.5 \mu g/m^3$. (Improve/Retain)

Response:

ADEC agrees with the EPA’s suggestions made to simplify the NOx precursor demonstration so that the primary tables that were used to make the precursor demonstration from 2013 and 2019 are in the modeling chapter and all alternative NOx sensitivity runs and sensitivity chemistry discussion were moved to the modeling appendix for weight of evidence. ADEC has made the changes to the NOx precursor demonstration in the modeling chapter (Section III.D.7.8).

BACM - General

EPA Comment (46):

BACM Identification and Analysis. Our review of the *Best Available Control Measures Analysis for Fairbanks PM2.5 Nonattainment Area* in Appendix III.D.7.07 indicates that ADEC appropriately identified multiple control measures for each source category based primarily on a survey of nonattainment areas in other jurisdictions. Note that the Clean Air Act and best practices do not preclude an area from evaluating measures not included in other nonattainment area plans, if such measures are available. See 40 CFR 51.1010(a)(2). Relatedly, the statutory definition of BACM does not allow the absence of a measure in other SIPs as the sole rationale for excluding new measures as technologically infeasible. 40 CFR 51.1010(a)(3). We are encouraged that ADEC has evaluated new measures focused on weatherization and boiler efficiency given their connection to the home heating source category. (Improve)

Response:

ADEC appreciates EPA's acknowledgement of identification and evaluation of new measures connected with the home heating source category. ADEC has reviewed the control measures noted as "MSM" which had not been implemented in another nonattainment area and were classified as an MSM to be addressed in a subsequent SIP. For those measures further review has shown that, in addition to not being implemented in another nonattainment area, those measures are not technically feasible to implement. Justifications vary from local arctic conditions to an inability to implement a measure in whole or in part within the required timeline. Those control measures were incorrectly identified as MSM, and are now identified under technical dismissal in the BACM crosswalk in the Control Measure Chapter. The BACM analysis in the Appendix III.D.7.07 has also been modified to incorporate these revisions.

There are several references to the timing requirements for BACM. 40 CFR 51.1000 defines BACM as "any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after the date of reclassification of a Moderate PM2.5 nonattainment area to Serious...". The preamble to the PM2.5 implementation rule under BACM Step 5 (page 58085) contains the same timing "Section 189(b)(1)(B) of the CAA requires that Serious area attainment plans provide for the implementation of BACM no later than 4 years after reclassification of the area to Serious."

The nonattainment area was reclassified to Serious on June 9, 2017 which, according to the above references, defines a BACM measure as any technologically and economically feasible control measure that can be implemented in whole or in part by June 9, 2021.

There is another reference to timing in 40 CFR 51.1010(a)(3) "The state may make a demonstration that any measure identified … is not technologically or economically feasible to implement in whole or in part by the end of the tenth calendar year following the effective date of designation of the area, and may eliminate such whole or partial measure...". Using this reference, BACM measures that could not be implemented in whole or in part by December 2019 could be eliminated. ADEC considers the June 9, 2021 date the applicable date for implementation of BACM.

EPA Comment (47):

Stakeholders Group. We commend both ADEC and FNSB for convening the Stakeholders process in 2018 to better engage the community for solutions to the Serious nonattainment issue. We also commend the stakeholders themselves for participation in the process to work to understand the issue and perspectives of all in the community. Looking forward, we encourage the state and the Borough to continue to revisit the measures that the stakeholders have generated, even if they do not make it into this attainment plan. (Improve/Retain)

Response:

ADEC appreciates EPA's acknowledgment of the local stakeholder process and its importance in understanding community perspectives for controlling PM2.5 in the nonattainment area. In future planning efforts, ADEC intends to continue to work with the Borough and stakeholders to consider measures and any new ideas generated by the community to help reduce PM2.5.

EPA Comment (48):

Non-selected Measures. On multiple occasions we noted the following issues with the rationale for not selecting a control measure: the concept of technological infeasibility was used incorrectly, a de minimis emissions concept not allowable by regulations was used, claims of equivalent stringency did not have sufficient supporting information, and the BACM analysis was not completed. In some of the situations, economical infeasibility analyses, technological infeasibility based on local arctic conditions or other rationale may be more appropriate for documenting a decision on a measure selection. See 40 CFR 51.1010(a)(3). (Improve)

Response:

ADEC has reviewed the control measures where EPA has identified that technological infeasibility was used incorrectly. The BACM analysis and dismissal methodology have been reviewed and modified. For control measures that do not have a quantifiable emission benefit, a statement has been added to the analysis to reflect that those control measures do not meet the definition of BACM. The 2016 PM2.5 rule 40 CFR 51.1000 definition of BACM includes the requirement that for control measures to be considered BACM they "generally can achieve greater permanent and enforceable emission reductions ... than can be achieved through implementation of RACM". A qualitative economic analysis has also been added to those measures showing that with no emission benefit and some associated cost to implement, the dollar per ton value would be infinite.

For control measures where EPA has identified that claims of equivalent stringency did not have supporting information, the analysis has been modified and those measures are not dismissed, but identified as adopted in different form. The equivalent regulation has been identified in those measures.

EPA Comment (49):

Motor Vehicle Controls. The BACM assessments of motor vehicle related controls incorrectly identifies that emissions benefits are not quantifiable as a rationale for dismissal of controls. Technological and/or economic infeasibility are the primary means by which to dismiss a control from selection per the 2016 PM2.5 rule. 40 CFR 51.1010(a)(3). Additionally, similar with the moderate area plan, motor vehicle idling control emissions reductions may be captured in the emission inventory, but not as an attainment demonstration control measure until the methodology is approved by OTAQ. (Improve)

Response:

EPA and FHWA have devoted considerable resources to develop tools to analyze the benefits of Transportation Control Measures (TCMs) as they were intended to help reduce mobile source emissions through transportation efficiency improvements and reductions in vehicle miles of travel. Independent analyses by the NCHRP (a division of the Transportation Research Board) and ASHTO (the American Association of State Highway and Transportation Officials), have documented that the initial enthusiasm for including TCMs in SIPs has diminished as states have gained experience with their benefits and learned that they produce small emission reductions as compared with those produced by technological advancements that produce cleaner vehicles and fuels. Thus, while CMAQ funding is being used to support the implementation of a variety of transportation measures in many communities, less emission reduction credit is being taken for them and they are more frequently being implemented as voluntary measures, for which emission reduction credit is limited.

The Moderate SIP, approved by EPA, identified the measures that have been implemented in Fairbanks and reached the following findings with regard to the implementation of additional measures:

- Measures focused on reducing traffic congestion offer limited benefits as the Fairbanks road network has few roads operating at Level of Service (LOS) levels D, E, or F.
- Community-wide ridesharing programs offer few potential emission reduction benefits because of the low population and employment density in the nonattainment area (employer programs are operated where sufficient density supports participation).

- Travel reduction programs have been found to have limited benefits on a national basis, with principal reductions coming from commute trips, which require high density employment to be successful.

This resulted in the conclusion that no additional TCMs appear viable for Fairbanks. Because TCMs were not expected to provide additional reductions, all TCMs were classified as "not technologically feasible"

The BACM analysis revisited these findings and determined that they had not changed - additional transportation control measures are technologically infeasible and not eligible for BACM. Both the BACM finding on motor vehicle controls and the EPA comment on the BACM finding for motor vehicle controls are incorrect.

The BACM conclusion incorrectly stated:

Findings for the transportation controls examined in the RACM analysis have not changed, these measures <u>are technologically infeasible</u> and not eligible for BACM. (emphasis added)

EPA incorrectly stated:

The BACM assessments of motor vehicle related controls incorrectly identifies that <u>emissions benefits are not quantifiable</u> as a rationale for dismissal of controls. (emphasis added)

With regard to the BACM finding, transportation control measures are technologically feasible; they have been implemented all over the country. That said, independent studies have documented that while states and communities continue to adopt them, where funding is available, growing experience in lower-48 states has demonstrated emissions benefits are limited. As a result, credit for TCMs in SIPs has diminished. This finding and the prospect of limited cost effective benefits in a low density arctic community supports Fairbanks decision not to include any additional TCMs in the Serious SIP. The text of the BACM document will be revised to clarify this finding.

With regard to the EPA finding, as shown in the conclusion listed above, the BACM analysis did not claim the emissions benefits of motor vehicle controls are not quantifiable. It did state:

> *Finally, the latest version of EPA's Motor Vehicle Emissions Simulator MOVES2014a continues to show no $PM_{2.5}$ benefits for either light- or heavy-duty I/M programs. Thus, there is no way <u>to quantify a particulate benefit from I/M</u>, and EPA clearly does not recognize I/M as an appropriate $PM_{2.5}$ control measure.* (emphasis added)

The latest MOVES release is MOVES14b and it continues to show no $PM_{2.5}$ benefits for either light- or heavy-duty I/M programs. Until EPA approves a methodology for quantifying PM2.5 benefits of I/M programs, the state cannot claim a benefit for it in the Serious SIP. Thus, the state agrees that the benefits of motor vehicle idling controls, if they exist, cannot be quantified or used in the emission inventory calculations until a methodology is approved by OTAQ.

EPA Comment (50):

BACM - Woodsmoke

Measure 7. We recommend ADEC further evaluate the feasibility of imposing a 1.0 grams/hour standard or provide further evaluation of whether the proposed control measures are equivalent to the Missoula County measure (Rule 9.203). Our review indicates that Missoula County imposed a 1.0 grams/hour standard for wood-fired hearting devices in a stagnation area that encompasses major portions of the City of Missoula, as described in the BACM analysis (Appendix III.D.7.07, page 33-34). (Improve/Retain)

Response:

The current test method that results in the certification value (grams PM/hr) averages emissions over four steady-state runs. The values from each of these runs is an average emission rate over the time it takes to burn 100% of the full load of wood used for each run. This approach translates into a certification value that is an average of an average. Averaging results multiple times minimizes emission rates, which results in certification values that may vastly under predict actual in-use emission rates and does not reflect the fuel loading events that in field use may occur multiple times per day.

Real-time PM measurements collected from EPA certification tests have shown that the maximum emission rate occurs within two hours of the test period, and typically, on average, appliances spend approximately 50% of the certification testing time in the period known as the charcoal tail, where virtually no emissions occur, and in some cases filters may experience particulate loss due to warm dry air blowing through the filter.

Given the likely under predicting of actual in-use emissions through the current certification method, ADEC proposed utilizing the tapered element oscillating microbalance (TEOM) for non-catalyst devices and planned to use the emission profiles to assist in ensuring performance and identifying actual emissions through the certification process. ADEC felt that additional scrutiny of actual emissions would provide more insight than the average of an average value. However, many adverse comments to using the TEOM (see page 51 for summary of TEOM-related public comments and ADEC response) and differentiating certification standards by device type were received.

Under the 2015 NSPS, EPA required reporting of emission rates for the first hour of the test period. This data reflects the timing and emission rates typically associated with the 60-minute test requirements for PM testing at all other sources (EPA Method 5). Assessment of one-hour data allows agencies to gauge performance and determine which appliances are low emitting from the start of the certification test versus those that have been able to design for long charcoal tails to minimize the peak emissions.

Based on a review of current certified wood heaters, the Missoula County measure requiring a 1.0 grams/hour emission standard essentially results in a pellet fueled device only requirement. In looking at pellet-only requirements for the FNSB nonattainment area, public concerns are often expressed about a fear of losing heat during power failure and pellet devices require electrical power to operate. Thus, DEC's proposal to include the TEOM was derived as an alternative that may produce similar emissions benefits while allowing access to a broader array of wood heaters.

In light of the comments received, DEC has analyzed over 60 EPA approved certification reports, focusing on the one-hour filter data measurement results. After this review, ADEC decided to amend the final regulation to provide an alternative to the TEOM test method that will address many of the comments received while still providing an equivalent, if not better, air quality result than the 1.0 grams/hr Missoula emission standard. In the final regulation, manufacturers may provide the TEOM data as originally proposed with the additional specificity that no rolling 60-minute period may exceed 4.0 grams/hr or they may meet the requirement to be a DEC listed device by providing data that shows that no valid 1-hr filter measurement from the certifying report to EPA is greater than 6.0 grams/hr. While this is 3 times the final DEC standard (certification value of 2.0 grams/hour or less), this will be applied to all woodstoves (not just non-catalytic), and will reduce the number of allowable devices into the area while still allowing more device types than just pellet fueled. This approach should ensure that performance of the devices under a more real world operation will be more consistent because the emission standard value is not an average. As an example, DEC found devices that meet the 1 grams/hr certification value, but do not meet the not to exceed 1-hr filter measurement of 6.0 grams/hr. Over time, and as more data becomes available, it is possible that ADEC could consider making the criteria for a maximum acceptable 1-hr filter measurement more stringent.

<u>EPA Comment (51):</u>

BACM - Fuels

Natural Gas. It will be important for the area to continue to pursue natural gas along with other liquid fuels used for home heating. These fuels have lower direct PM emissions and will be important to the long-term emissions control strategy. Diversification in fuel choices with lower associated emissions may be important to allow for growth within the nonattainment area while not negatively affecting air quality. (Retain)

Response:

ADEC appreciates EPA's comment and continues to track the progress of the natural gas infrastructure build out within the nonattainment area. ADEC will continue to update its future SIPs to revisit potential controls that take advantage of enhanced natural gas availability as the Interior Gas Utility is able to increase service to additional customers.

Comments other than EPA Comments

This portion of the document addresses the aggregated comments from private individuals, organizations, businesses, governmental officials, industry, and elected officials. For each section of the proposed regulations and for the State Implementation Plan (SIP), the document summarizes comments received and provides ADEC's responses and decisions.

Comments received regarding:

18 AAC 50.030 and SIP

Summary of Comments:

Comments received on the incorporation of the proposed amendments of the State Air Quality Plan into regulation at 18 AAC 50.030 expressed a variety of support and concern. Many commenters noted that the proposal would enhance clean air in the community and avert sanctions such as the loss of highway funds. Other commenters stated the proposal is an obstruction of citizens' rights and that its implementation would create a financial hardship. They proposed a moratorium until alternatives such as natural gas and other infrastructures are available. Commenters suggested that ADEC should consider the inputs of the Air Quality Stakeholders Group and those received during the public comment period. Commenters also recommended that the department, at the beginning of each heating season, present an annual report card on the air quality status to the public and other regulated source sectors. They stated that the public needs to be aware of information such as compliance rate measurements, enforcement activities, penalties levied, availability of dry wood, progress towards attainment, and new technologies on a yearly basis.

Response:

ADEC understands that the proposed Serious SIP generates both support and concerns within the community. In order for the SIP to be successful it must find a balance and have acceptance by the community in order for the identified measures to ultimately be successful in reducing PM2.5. ADEC's objectives are to develop an effective plan that can improve air quality to meet the National Ambient Air Quality Standards and avoid sanctions and consequences under federal law. The control measures being implemented in the nonattainment and the new measures proposed have economic implications for local businesses and area residents; ADEC considered fiscal impacts and appreciates that members of the community provided data and input of their fiscal concerns during the public review of the SIP. The final Serious SIP includes many of the recommendations of the local Air Quality Stakeholders Group and those measures that were not included could potentially be advanced through local community efforts or revisited in future plans.

ADEC appreciates that the public wants data and information on the implementation and effectiveness of the programs implemented under the SIP and the progress being made to attain the standard. ADEC understands the need for such data to meet planning requirements and will collect data for use in determining the effectiveness of programs, producing required progress reports for EPA, and communicating information about the programs to the public and elected officials. ADEC works with the Borough to provide progress updates to the FNSB Assembly and Air Pollution Control Commission as requested and at least annually.

The overall responsiveness summary further addresses comments received on the Serious SIP and associated regulations and outlines areas where revisions were made to the final Serious SIP.

18 AAC 50.075 - Visible Emissions

Summary of Comments:

18 AAC 50.075(e):

There was overwhelming support in the comments received on the proposed regulation revisions regarding the prohibition of operation of a solid fuel-fired heating device when the department declares a $PM_{2.5}$ air quality emergency episode in the nonattainment area. Many commenters noted that citation authority is needed to enforce the proposed regulation. Other commenters suggested that the department should devote resources to the planning and collection of compliance rate information every year. They stated that the action would give credibility to the emission reductions estimates achieved by alerts. Comments also noted that the information would help in preparing quantitative milestone and reasonable further progress reports. Other benefits of the action, as highlighted in the comments, include the development of enforcement program management and the assessment of public responsiveness, for the review of the public and policymakers.

Response:

ADEC acknowledges the public comments that express the desire for the department to have citation or administrative penalty authority to enforce state regulations in the nonattainment area. While ADEC agrees that such authority could result in efficiencies for enforcement actions related to the programs, the power to grant this authority lies with the Alaska State Legislature, which would need to pass legislation. At this time, no legislation on this topic has been introduced for consideration. As a result, ADEC will continue to use its current civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area. The ADEC Air Quality Division has relied successfully on its current authorities in implementing the CAA programs for decades.

With respect to the on-going collection of compliance data, ADEC understands the need for such data to meet planning requirements and will collect data for use in determining the effectiveness of programs, producing required progress reports for EPA, and communicating information about the programs to the public and elected officials.

18 AAC 50.075(e)(3):

Comments received on this section of the proposed regulation revisions requiring a shutdown of the operation of a solid fuel-fired heating device within three hours of the declaration of burn ban are few. The comments consisted of a combination of support and concern. Comments noted that ADEC would need an increased budget and commitment, as well as citation authority to enforce the proposed regulation. Some commenters felt that all wood- and coal-fired devices should be banned permanently from operating in the nonattainment area. They stated that these devices contribute enormously to the air pollution in the area. Other commenters argued that the 3-hr window is unrealistic and unreasonable. They argued that it would be difficult for working people and students, who might not be home when a burn ban is called, to comply with the regulation. Comments also noted that it is impossible not to have visible smoke, within three hours of declaration, from stoves that have been burning for several hours.

Response:

ADEC acknowledges the public comments that express the desire for the department to have citation or administrative penalty authority to enforce state regulations in the nonattainment area. While ADEC agrees that such authority could result in efficiencies for enforcement actions related to the programs, the power to grant this authority lies with the Alaska State Legislature, which would need to pass legislation. At this time, no legislation on this topic has been introduced for consideration. As a result, ADEC will continue to use its current civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area. The ADEC Air Quality Division has relied successfully on its current authorities in implementing the CAA programs for decades.

With respect to concerns expressed about the need for increased budget and resources to implement the measure, ADEC is committed to funding and implementing the measures included in the Serious SIP. The ADEC budget is determined annually by the Alaska State Legislature and the Division relies on a mix of federal and state general fund revenue to operate this program. The Division of Air Quality is prioritizing work to ensure efficient and effective implementation of all committed measures and will continue to do so.

ADEC received comments that all solid-fuel heating devices be banned, but also received comments suggesting that they continue to be allowed for use. This is clearly an area where there is not consensus within the community. ADEC acknowledges that the banning of all solid-fuel heating devices would eliminate the primary source of fine particulate in the nonattainment area and eliminate the need to define burn down periods when curtailments are called. However, ADEC often hears from FNSB residents who have significant concerns regarding the need for non-electric backup heating systems in their homes. Given the subarctic climate and periodic power failures, these individuals have real safety concerns for themselves and their families as well as concerns about damage to their property. As a result, ADEC is attempting to limit solid-fuel burning emissions through a more balanced approach that relies on burn curtailments during air episodes, requirements for best burning practices such as the use of dry wood, and stringent emission standards for any new wood heaters installed within the area. The wood heater change out and conversion program is also improving the viability for non-solid fuel options to meet residential heating needs within the community. ADEC's plan indicates that over time, these measures (and others) will bring the area into attainment with the health-based standards.

ADEC recognizes the challenges expressed regarding the 3-hr burn down period. To assist with the concerns raised, the 3-hr burn down period will be included in the curtailment announcement. The curtailment announcement timing is approximately at 2:00 pm and hopefully prevents reloading of a device after a normal work day end of 5:00 pm. For those Fairbanks residents with different working schedules, ADEC will take into consideration the timing of the announcement with their work or school schedules should they be identified as noncompliant with a curtailment.

18 AAC 50.075(f):

Comments received on this section of the proposed regulation revisions prohibiting visible emissions from solid fuel-fired devices from crossing the property lines expressed varying levels of support and concern. Some commenters noted that ADEC would need to increase surveillance and acquire citation authority to enforce the proposed regulation. Comments also suggested educating offenders about compliance requirements and options and following through with penalties for repeat offenders. Other commenters mentioned that it is difficult to differentiate between steam and wood smoke.

Response:

ADEC acknowledges the public comments that express the desire for the department to have citation or administrative penalty authority to enforce state regulations in the nonattainment area. While ADEC agrees that such authority could result in efficiencies for enforcement actions related to the programs, the power to grant this authority lies with the Alaska State Legislature, which would need to pass legislation. At this time, no legislation on this topic has been introduced for consideration. As a result, ADEC will continue to use its current civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area. The ADEC Air Quality Division has relied successfully on its current authorities in implementing the CAA programs for decades.

ADEC agrees with the comments supporting education and compliance assistance to help individuals comply with requirements. Division of Air Quality staff use education and assistance on how to burn cleanly as a first step in the compliance and enforcement process. Often, this is all that is needed to help individuals understand and comply with visible emission requirements. The Division's "Burn Wise Alaska" web site (https://dec.alaska.gov/air/burnwise/) contains much valuable information on best burning practices. For repeat offenders, ADEC is prepared to advance individual compliance cases to formal enforcement under our current statutory authorities.

In observing visible emissions for compliance, ADEC staff rely on EPA Method 9 with Alaska specific modifications that address water vapor. More information on visible emission evaluation procedures can be found on the Division's web site at: https://dec.alaska.gov/air/burnwise/opacity/.

Fiscal Concerns:

No fiscal concerns were noted in public comments on this section of the regulation.

Department Decision:

ADEC made no substantive changes to the proposed revisions to 18 AAC 50.075 based on public comments received. The department revised the language in 18 AAC 50.075(f) to correct an inaccurate cross reference and to clarify language.

18 AAC 50.076 - Wood Sellers

Summary of Comments:

Comments on this section of the proposed regulation revisions expressed varying levels of support and concern for the sale of dry wood by commercial wood sellers in the Serious nonattainment area after October 1, 2021. Some commenters wanted the implementation to start in 2020. They said since it takes wood nine months to dry, there would still be enough time to meet the schedule. Other commenters felt that drying of wood should be the responsibility of the burners. They said the proposed regulation would put many wood sellers out of business, raise wood costs, and push people to burn wet wood. Some commenters felt that banning of wood stoves in the nonattainment area is more effective and cost-effective than trying to regulate wood moisture content. Other commenters requested an increase in access to spruce beetle-eaten and fire-killed wood. Other comments noted that the sale of green firewood should be allowed during the offseason to allow enough time for drying. Several comments suggested there should be the provision of community kilns to increase the availability of dry wood. Other commenters asked ADEC to consider a program that encourages the exchange of wet wood with dry wood. Some commenters recommended that ADEC should quantify the annual wood volume and space needed for wood storage. They asked ADEC to meet with wood suppliers to come up with the alternative options of meeting the dry wood mandate by the proposed September 30, 2021.

Some commenters requested changing the terms "commercial wood sellers" to "firewood or space heating wood sellers" to avoid confusion with the wood sold for manufacturing or milling purposes. Other commenters requested replacing the split and store requirement with the language that the dry wood could be inspected and verified by ADEC staff. Comments also suggested adding an exclusion for 8-foot rounds in the proposed regulation. Some commenters believed that continued education is needed to encourage people to burn wood responsibly. Other commenters felt that citation authority with adequate funding is required to enforce the proposed regulation.

Response:

ADEC is federally required to consider all the Best Available Control Measures (BACM) from other PM nonattainment areas across the nation and one of those BACM controls is requiring the sale of only dry wood in a nonattainment area. This type of measure focuses on the FNSB nonattainment area's primary source of PM2.5 pollution, wood smoke from space heating. ADEC already has regulatory requirements for individuals to burn only dry wood in their wood-fired heating devices. The current requirement in combination with other existing controls has not been sufficient to bring the area into attainment by the 2019 deadline. Requiring that only dry wood be sold will help to ensure the wood used by local residents who buy their wood supply is compliant and will lead to further reductions in smoke impacts by reducing the burning of wet wood.

Given the range of comments received, the following list provides responses on a number of topics related to the dry wood sale requirement:

- *Timing for implementation and impacts to wood sellers:* ADEC delayed the implementation of the dry wood sale requirement to October 1, 2021 to allow a minimum of two summer seasons for wood sellers to develop their plans for seasoning wood in advance of sales while still being able to sell green/wet wood in the interim. Wood selling businesses have several options they could consider to provide dry wood including cutting/storing wood with enough time to properly seasoning it prior to sale, mechanically drying wood by kiln or other mechanism, or seeking sources of fire-killed or other standing dry timber for processing and sale. The time provided should allow for businesses to make decisions that best fit their situation.
- *Allow for wood sellers to have wood inspected dry prior to 9 months of seasoning:* ADEC included the 9 month wood seasoning provision based on prior testing done by the Cold Climate Housing Research Center that looked at the time needed to reliably reach 20% moisture content after splitting, stacking, and storing wood. ADEC agrees that if sellers find that their wood is dry prior to 9 months, they should be able to sell the wood. The final regulations were clarified to provide for confirmation of dry wood prior to the end of the 9 month window.
- *Provide for wood-drying kilns and/or wet wood exchange program:* ADEC agrees that wood-drying kilns or a wet for dry wood exchange program could be viable options for wood sellers and individuals to efficiently dry wood in shorter periods of time. ADEC is not requiring the construction or use of kilns or implementation of wood exchange programs through the SIP, but that does not prevent local businesses or residences from implementing these ideas. ADEC does not have the resources to incentivize or support the construction of kilns or implementation of a wood exchange program.
- *Continue to allow sale of green/wet wood during certain times*: Because it can take up to 9 months for wood to season in the local area, ADEC could not identify a reasonable scenario that would allow for the continued sale of split green wood and

meet the intent of, or benefits associated with, the BACM requirement to implement dry wood only sales. As a result, no change was made to the SIP to allow for the sale of split green wood, however ADEC is making a revision related to the sale of unseasoned 8-foot round logs as described below.

- *Continue to allow sale of 8-foot round logs:* ADEC received a number of comments suggesting that the sale of 8-foot round logs should be allowed to continue in the future. These comments asserted that many buyers of 8-foot rounds have multi-year storage capacity and process their logs years in advance to ensure proper seasoning. ADEC recognizes that 8-foot rounds cannot be burned as is, but must be processed by the buyer so this wet wood can't be immediately burned without some up front effort. This means that buyers can't easily or unintentionally add this wood to their heating device. ADEC is therefore revising the final regulations to accommodate the continued sale of 8 foot rounds, but has added provisions that these sales can only occur if the wood seller confirms that the buyer will not burn wet wood in the coming season based on dry wood supply and storage/processing capacity for seasoning wood. ADEC believes that this revision addresses FNSB specific considerations and with the additional confirmation step on the buyer's wood supply/storage would remain consistent with the BACM requirement for dry wood only sales.
- *Define commercial wood seller as firewood seller*: ADEC already defines commercial wood seller in this manner in existing regulation at 18 AAC 50.076(h). This section of the regulation was not proposed for revisions or released for public comment, but ADEC will consider in future regulation packages whether additional clarification is helpful.
- *Ban wood stoves in nonattainment area*: ADEC received comments that ranged from banning all wood heating devices to continuing to allow for use of wood heating devices and treating all types of solid-fuel heaters equally based on their emission rates. ADEC acknowledges that the banning of all wood heating devices would eliminate the primary source of fine particulate in the nonattainment area. However, ADEC often hears from FNSB residents who have significant concerns regarding the need for non-electric backup heating systems in their homes. Given the subarctic climate and periodic power failures, these individuals have real safety concerns for themselves and their families as well as concerns about damage to their property. As a result, ADEC is attempting to limit wood smoke emissions through a more balanced approach that relies on burn curtailments during air episodes, requirements for best burning practices such as the use of dry wood, and stringent emission standards for any new wood heaters installed within the area. The wood heater change out and conversion program is also improving the viability for non-solid fuel options to meet residential heating needs within the community. ADEC's plan indicates that over time, these measures (and others) will bring the area into attainment with the health-based standards.
- *Quantification of wood volume and space needed:* ADEC delayed the implementation of the dry wood sale requirement to October 1, 2021 to allow a minimum of two summer seasons for wood sellers to develop their plans for seasoning wood in

advance of sales while still being able to sell green/wet wood in the interim. Wood selling businesses have several options they could consider to provide dry wood including cutting/storing wood with enough time to properly seasoning it prior to sale, mechanically drying wood by kiln or other mechanism, or seeking sources of fire-killed or other standing dry timber for processing and sale. The time provided should allow for businesses to make decisions that best fit their situation this includes determining any space needed based on the business approach selected.

- *Adequate enforcement and resources:* ADEC acknowledges the public comments that express the desire for the department to have citation or administrative penalty authority to enforce state regulations in the nonattainment area. While ADEC agrees that such authority could result in efficiencies for enforcement actions related to the programs, the power to grant this authority lies with the Alaska State Legislature, which would need to pass legislation. At this time, no legislation on this topic has been introduced for consideration. As a result, ADEC will continue to use its current civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area. The ADEC Air Quality Division has relied successfully on its current authorities in implementing the CAA programs for decades.

  ADEC is committed to funding and implementing the measures included in the Serious SIP. The ADEC budget is determined annually by the Alaska State Legislature and the Division relies on a mix of federal and state general fund revenue to operate this program. The Division of Air Quality is prioritizing work to ensure efficient and effective implementation of all committed measures and will continue to do so.
- *Potential impact of increased wood cost*: ADEC acknowledges that dry wood currently costs significantly more to purchase than wet wood within the nonattainment area. ADEC estimates that 60% of residents burning wood cut their own supply and thus this measure would only impact costs for the remaining residents that purchase wood. There is potential that as a result of increased costs for purchasing wood, more residents may choose to cut their own wood or they may choose to seek to convert out of wood heating to a non-solid fuel heating alternative through the FNSB change out and conversion program. There is also the potential that, depending on the mechanism chosen to provide dry wood, the dry wood cost could normalize and potentially result in a smaller cost deferential. As described above, ADEC has provided time until October 2021 for both wood sellers and purchasers to plan and budget ahead to meet their own specific situation with respect to ensuring a dry wood supply.
- *Public education*: ADEC agrees with the comments supporting education and compliance assistance to help individuals comply with requirements. Often, this is all that is needed to help individuals understand and comply with wood burning requirements. The Division's "Burn Wise Alaska" web site (https://dec.alaska.gov/air/burnwise/) contains much valuable information on best

burning practices. ADEC remains committed to working with the Borough on public education and outreach in the nonattainment area.

- *Increase access to standing dry wood (ie. beetle/fire killed)*: ADEC currently works with wood sellers to confirm dry wood stands as part of the existing moisture content disclosure program, but the agency does not have the programs or authority to open up additional stands of beetle-killed or fire-killed timber for wood cutting.

<u>Fiscal Concerns:</u>

Responses to comments received regarding costs to consumers and wood sellers are included above.

<u>Department Decision:</u>

ADEC revised the proposed regulation to allow for wood sellers to confirm wood is dry earlier than the 9 month seasoning window outlined in the regulation.

ADEC revised the proposed regulation to provide an exclusion for the sale of 8-foot round logs provided the seller continues to meet all moisture disclosure reporting/documentation requirements and confirms that the wood buyer will not burn wet wood in the coming season based on dry wood supply and storage/processing capacity for seasoning wood.

ADEC made other clarifying language changes to this section of regulation to address the new language and other legal considerations.

18 AAC 50.077 - Standards for wood-fired heating devices

<u>Summary of Comments</u>

18 AAC 50.077(b):

Comments on the proposed regulations requiring the removal of all uncertified devices and non-pellet wood-fired outdoor hydronic heaters by the earlier of December 31, 2024, or before lease or sale as part of the existing building and their subsequent destruction, expressed a variety of support and concern. Some commenters noted that the most effective way of reducing air pollution in the nonattainment area is to remove all solid fuel devices. Many of the comments suggested a removal date of 2020 or 2022. Commenters stated that ADEC should prohibit the sale and installation of all types of hydronic heaters as the devices produce higher emissions than all other heating sources. Several comments also supported the removal of old and all uncertified devices. Some commenters warned against the use of the removed heating devices outside the nonattainment area. They stated that the use of these devices in other areas could lead to the creation of another nonattainment area. Commenters noted that citation authority is needed to enforce the proposed regulation.

Some commenters stated that the ADEC should incentivize change-outs instead of proposing the removal of uncertified devices. They said the implementation of the proposals would create economic hardship and impact the market negatively. Comments also noted that the proposed regulations would not work because of the costs of inspection and enforcement. Some commenters noted that the installation of EPA-certified non-pellet fueled wood-fired hydronic heaters should be allowed. Other commenters felt that ADEC should allow the installation of new coal heating devices that meet the standard of 18 g/h of particulate emissions. They said that there should be consistent standards for all wood solid-fuel devices. Commenters noted that that ADEC should be concerned about the efficiency or emissions rates per unit of energy of the devices instead of fuel types or the specific devices.

Commenters suggested a crackdown on fireworks and campfires instead of regulation of wood stoves. Several commenters suggested that the use of retrofit devices should be considered as a form of conformance of emission standard and exemption for solid fuel heating devices during burn bans. Comments also noted that ADEC should provide incentives to landlords to encourage them to install certified devices in their rental units. Other commenters suggested that seasonally-occupied residencies should be exempted from replacing wood stoves that are older than 25 years. Some comments also noted that the only solution to the air pollution in the area is a change of fuel to the clean-burning propane.

Response:

ADEC appreciates the suggestion of earlier removal of all uncertified devices and non-pellet wood-fired outdoor hydronic heaters from the nonattainment area. However, the slightly longer timeframe provides the opportunity for residents to consider and potentially take advantage of the change out/conversion programs and alternative fuels such as propane or the expanded natural gas service planned for the community in the coming few years. While ADEC acknowledges that the regulation may bring economic burden to the residents, all attempts have been made to lessen the potential burdens as much as possible.

With respect to comments suggesting the banning of all wood heating devices, ADEC acknowledges that the banning of all wood heating devices would eliminate the primary source of fine particulate in the nonattainment area. However, ADEC also heard from FNSB residents who have significant concerns regarding the need for non-electric backup heating systems in their homes. Given the subarctic climate and periodic power failures, these individuals have real safety concerns for themselves and their families as well as concerns about damage to their property. As a result, ADEC is attempting to limit wood smoke emissions through a more balanced approach that relies on burn curtailments during air episodes, requirements for best burning practices such as the use of dry wood, and stringent emission standards for any new wood heaters installed within the area. The wood heater change out and conversion program is also improving the viability for non-solid fuel options to meet residential heating needs within the community. ADEC's plan indicates that over time, these measures (and others) will bring the area into attainment with the health-based standards.

While ADEC does not have the citation authority that could result in efficiencies for enforcement actions related to the programs, it does have civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area.

It is not possible to treat all devices based on emissions rates per unit of energy because emission rates per unit of energy does not cap overall emission from a single residence because of the variation of fuel used. However, the use of emission rates per hour does allow emissions to be capped. ADEC appreciates the community interest in ESPs as a technology that could assist in improving the area's air quality. However, until there is additional data, ADEC is limited in its ability to provide regulatory incentives to using the devices. While additional testing is being conducted, ADEC has included ESPs into the Stage 1 and NOASH waiver programs within the Episode Chapter as an initial step acknowledging the potential benefits of this new retrofit technology. ADEC is supporting the use of Targeted Air Shed Grants to assist with conversion programs to any liquid fuel, including propane.

Department Decision:

The Department's decision is to treat all woodstoves equally based on their emission rating. Therefore, non-catalyst woodstoves, catalyst woodstoves, and pellet woodstoves now have the same requirements.

The Department also reorganized 18 AAC 50.077. 18 AAC 50.077(e), the proposed section that defined the requirements for catalyst equipped and pellet fueled woodstoves has been renumbered and all woodstoves are now addressed in the adopted regulations at: 18 AAC 50.077(c).

18 AAC 50.077(d):

Comments received on this section of the proposed regulation revisions requiring emissions standards of either annual average emission limit of 2.0 g/hr or average emission level of 0.10 lbs./MMBtu of heat output were few. There were varying levels of support, but many of the commenters suggested that emissions standards should be applied consistently to all solid-fuel burning devices. Some comments noted that the focus should be on emission rates per unit of energy instead of trying to ban specific devices.

Response:

The Department acknowledges the desire that all solid-fuel burning devices have emission standards applied consistently and the desire for emission rates per unit of energy. However, federal certification processes treat solid-fuel burning differently and the differences are often times dependent on how a device is manufactured for use versus how it is tested for certification. In addition, emission rates per unit of energy are based on the amount of fuel that is used in the device, whereas emission rates per hour focus on what is coming out of the stack. Using emission rates per unit of energy do not cap overall emission from a single residence because of the variation of fuel used. However, the use of emission rates per hour does allow for emissions to be capped.

Fiscal Concerns:

There were no fiscal concerns noted in public comments on this section of the regulation.

Department Decision:

The Department has decided to treat all woodstoves equally rather than require additional testing for non-catalyst devices. The Department will stay aligned with federal regulations regarding the differences between woodstoves, hydronic heaters, coal fired devices, etc., and continue using the emission rates per hour.

The Department also reorganized 18 AAC 50.077 for clarity purposes. 18 AAC 50.077(d), the proposed section that established the 0.10 pounds per million Btu for pellet fueled hydronic heaters has been renumbered and is now addressed in the adopted regulations as: 18 AAC 50.077(b).

18 AAC 50.077(f):

A number of comments were received concerning the use of the tapered element oscillating microbalance (TEOM) for non-catalytic wood stoves. Commenters focused on a number of consistent themes with their concerns. Many commenters felt that the new testing requirement for non-catalytic stoves is unnecessary and would provide no emission benefits. They said the proposed regulation would only create additional costs for the manufacturers, limit consumer choices, and affect small businesses. Commenters questioned the separating out of technologies. They argued that while non-catalytic stoves have more uncontrolled emissions, catalytic stoves degrade faster and also produce uncontrolled emissions during startup because of its bypass device. Several commenters argued that TEOM is an unvetted testing method used only for Research and Development purposes. They said there are no laboratories (including EPA certified labs) that have used the test method. Commenters noted that TEOM has issues with data continuity as the filter in the instrument is susceptible to plugging and requires frequent change. Other commenters asserted that the purpose of the test method is to capture startup emissions. They said the data from the manufacturers of TEOM does not support its use for monitoring wood stove PM emissions. Some commenters noted that ASTM cordwood test is better and preferable because it has a vetted dilution tunnel procedure and standard flow settings. They also stated that TEOM has poor sensitivity to semi-volatile particles and humidity.

Some commenters claimed that the data presented by NESCAUM only showed startup emissions between catalytic and non-catalytic stoves. They urged ADEC to remove the data from the Serious SIP, arguing that they are incomplete, limited, and unlikely to be approved by the EPA. Comments also noted that the use of crib fuel for compliance, instead of cordwood used in the real world, is a waste of time. Other commenters said they are unaware of any organized inter-laboratory evaluations or EPA’s review of the test method. Many commenters asked for more information on the precision, cost, repeatability, and limitations of the test method. Other commenters suggested adhering to the vetted NSPS with the prescribed test methods as testing process takes the EPA a period of about one to two years. They added that there are still many wood stoves at the EPA certified test labs waiting for the new 2020 NSPS testing.

There were also commenters that indicated support for all changes proposed to the wood-fired device standards, including the use of a TEOM for non-catalytic devices.

Response:

The current test method, that results in the certification value (certified emission rate), averages emissions over four steady-state runs. The values from each of these runs is an average emission rate over the time it takes to burn 100% of the full charge of wood. This approach translates into a certification value that is an average of an average. Averaging results multiple times minimizes emission rates, which results in certification values that may vastly under predict actual in-use emission rates, and does not reflect the fuel loading events that in field use may occur multiple times per day.

Real-time PM measurements collected from EPA certification tests have shown that the maximum emission rate occurs within two hours of the test period, and typically, on average, appliances spend approximately 50% of the certification testing time in the period known as the charcoal tail, where virtually no emissions occur, and in some cases filters may experience particulate loss due to warm dry air blowing through the filter.

Under the 2015 NSPS, EPA required reporting of emission rates for the first hour of the test period. This data reflects the timing and emission rates typically associated with the 60-minute test requirements for PM testing at all other sources (EPA Method 5). Assessment of one-hour data allows agencies to gauge performance and determine which appliances are low emitting from the start of the certification test versus those that have been able to design for long charcoal tails to minimize the peak emissions.

The Department also recognizes that the TEOM is a new approach for certification testing and acknowledges the concerns regarding potential increased costs to certification testing as well as the back log of testing that manufacturers and EPA certified labs are facing in their efforts to meet the 2015 NSPS Step 2 standards in May 2020. The Department also acknowledges that the proposed regulations using the TEOM needed to include more detail. It should also be noted, that contrary to some commenters, use of a TEOM has been formally incorporated into measurements other than ambient monitoring. ASTM D6831-11, entitled “Standard Test Method for Sampling and Determining Particulate Matter in Stack Gases Using an In-Stack, Inertial Microbalance” is an example.

The Department is also faced with federal requirements for Best Available Control Measure (BACM) requirements. Measure 7 in the BACM analysis is Missoula County’s 1.0 grams/hour emission rate standard that is more stringent than the NSPS Step 2 standards of 2.0 grams/hour. The Department acknowledges the community desire for a range of device options and its reluctance to reduce the options for solid fuel fired devices. However, the Missoula standard is in essence a pellet only standard. One of the proposed approaches for requiring the use of TEOM measurement data was to provide a more meaningful equivalency to Measure 7 while still allowing a range of devices to be sold and used in the Fairbanks North Star Borough nonattainment area.

Fiscal Concerns:

Fiscal concerns were noted in public comments on this section of the regulation related to manufacturer costs. ADEC addressed these concerns by allowing the use of certification test data that is already generated to meet federal requirements; this approach alleviates the cost of an additional testing requirement.

Department Decision:

The Department decided to maintain the TEOM requirement with more specification but also provides an alternative requirement that will not require any additional testing because it utilizes existing EPA certification test data. Although the TEOM has been incorporated into ASTM D6831-11, it is still new in the application of certification test measurements. DEC believes the TEOM test is a valuable tool that should be used in the future and has maintained it as one option for meeting testing requirements in the final regulation. However, the TEOM requirement and its alternative will not be applied to just non-catalyst devices, but all woodstoves (catalyst equipped, non-catalyst, and pellet). The final regulation will also delay the new testing requirement until September 1, 2020. Applying this requirement to all woodstoves is in response, in part, to commenters desire for all wood devices to be treated the same. The time delay will allow community retailers to review their current inventory and make any adjustments if needed. This delay will also allow time for manufacturers to prepare for the requirement.

The specificity to the TEOM requirement and its alternative is based on the Department's analysis of over 60 EPA approved certification reports, the vast majority of the tests reviewed were for EPA Step 2 certification. The analysis focused on the required one-hour filter data measurement results. Based on this analysis, if the TEOM method is used, then no rolling 60-minute period may exceed 4.0 grams per hour. As an alternative, no valid 1-hr filter measurement of the certification report used to certify the device may be greater than 6.0 grams/hr. While this is 3 times the current DEC standard (certification value of 2.0 grams/hour or less), this will be applied to all woodstove (not just non-catalytic), and will reduce the number of allowable devices into the area, however it will be using a more meaningful approach and continuing to allow a range of devices.

The Department also reorganized 18 AAC 50.077 for clarity purposes. 18 AAC 50.077(f), the proposed section that established the 2.0 gram per hour emission rate and required a TEOM test has been renumbered and all woodstoves are now addressed in the adopted regulations at: 18 AAC 50.077(c).

18 AAC 50.077(e) & (f):

Additional comments regarding wood-fired devices themselves were are also submitted. These comments were focused on the type of wood fired device, catalyst, non-catalyst, pellet and hydronic heaters. Some commenters felt that all non-pellet wood fired and coal fired devices should be banned. Others felt that all hydronic heaters should be banned, even EPA-qualified pellet hydronic heaters. Comparisons were made regarding the proposal to require a fuel oil switch and the existing hydronic heaters in the area. It was indicated that if all the unqualified and Phase 2 qualified outdoor hydronic heaters were removed that the fuel switch would likely not be needed.

Commenters requested additional information on the 'Burn Right' program given the SIP mentions the Burn Right program in relation to masonry heaters. Additional clarification was requested to ensure to allow for only one dry cabin per 2 + acre lot to be constructed with a primary solid fuel burning appliance.

Some commenters felt that in order to continue to burn wood that the right equipment is essential. Others felt the type of device isn't the issue only the pollution output or emissions per BTU and to recognize new technology. Some noted that catalytic stoves degrades faster and that there should be some maintenance requirement in the regulations and that catalytic stoves had more uncontrolled start up emissions. There was also a request for a specific inclusion of a specific non catalytic device on the department's device list.

Some commenters were in general support of the overall regulation and some were unsupportive of any regulation.

<u>Response:</u>

ADEC received comments that ranged from banning all wood heating devices to continuing to allow for use of wood heating devices and treating all types of solid-fuel heaters equally based on their emission rates. ADEC acknowledges that the banning of all wood heating devices would eliminate the primary source of fine particulate in the nonattainment area. However, ADEC often hears from FNSB residents who have significant concerns regarding the need for non-electric backup heating systems in their homes. Given the subarctic climate and periodic power failures, these individuals have real safety concerns for themselves and their families as well as concerns about damage to their property. As a result, ADEC is attempting to limit wood smoke emissions through a more balanced approach that relies on burn curtailments during air episodes, requirements for best burning practices such as the use of dry wood, and stringent emission standards for any new wood heaters installed within the area. The wood heater change out and conversion program is also improving the viability for non-solid fuel options to meet residential heating needs within the community. ADEC's plan indicates that over time, these measures (and others) will bring the area into attainment with the health-based standards.

The Burn Right Program is a voluntary conceptual program that is intended to acknowledge those individuals who wish to demonstrate their ability to burn properly and use dry wood. It is also intended to assist in areas that do not have defined certification, such as masonry heaters. This program will evolve over time as ADEC works with those interested in participating in the community, and as such, more detail will be provided in future SIP amendments.

ADEC recognizes and acknowledges comments received regarding the right type of equipment being needed. It also recognizes the need to recognize new technology as well as maintenance. ADEC will continue to add information to the SIP on new technology as it becomes available. Testing by FNSB and ADEC will bring more insight, hopefully before the next SIP update. ADEC has also added additional maintenance requirements in the waiver program within the Episode Plan to address those comments received regarding catalytic devices.

Department Decision:

Outdoor hydronic devices, except pellet hydronic devices, will no longer be allowed to be installed within the nonattainment area. ADEC will continue to develop the Burn Right Program. ADEC will require maintenance of all devices prior to issuing any waivers.

The Department also reorganized 18 AAC 50.077 for clarity purposes. 18 AAC 50.077(e) and (f), the proposed sections that focused on wood stoves (e) on catalyst and pellet, (f) on non-catalyst has been renumbered and all woodstoves are now addressed in the adopted regulations at: 18 AAC 50.077(c).

18 AAC 50.077 (k)(1):

Comments were received regarding the requirement for registration of wood-fired heating device. The proposal limited registration to the following areas; upon the sale of a new device by the device vendor, prior to closing if device is being sold as part of an existing building or property, prior to issuance of any waivers, prior to closeout of any compliance or enforcement action, in order to participate in the Burn Right Program, in order to participate in any wood-stove change-out or conversion program. Commenters were supportive of the requirements and some expressed a desire for the requirement to be expanded to all devices (wood fired, oil-fired, gas, propane, etc.) as was recommend by the Stakeholder Group. Others saw no reason to require registration of heating devices, that the requirement should be removed, and felt it was just raising the cost of the program. There was a request for more information regarding the Burn Right Program. Suggestions were made to grandfather existing wood stoves and only require registration on change of status.

Response:

Registration of all heating devices was the number one recommendation of the local Stakeholder Group because they recognized the need to accurately understand the inventory of devices within the nonattainment area. Registration is also a requirement of the Best Available Control Measure (BACM) analysis. However, ADEC heard the dissenting concerns during the Stakeholder process and attempted to craft the registration requirement to focus on very specific times when individuals are subject to or interacting with DEC or FNSB programs rather than on an area wide registration mandate that would have been difficult if not impossible to implement. The times when the registration requirement will be implemented are coupled to programs and the costs are therefore within the current budget of the Division. All current devices are grandfathered from registration unless they wish to have a waiver, are being sold, or if the owner wishes to participate in a change out or conversion program.

The Burn Right Program is a voluntary program under development that is intended to acknowledge those individuals who wish to demonstrate their ability to burn properly and use dry wood. It is also intended to assist in areas that do not have defined certification, such as masonry heaters. This program will evolve over time as ADEC works with those in the community interested in participating and more detail will be provided in future SIP amendments.

Department Decision:

The regulations will remain as proposed except for minor edits.

The Department also reorganized 18 AAC 50.077 for clarity purposes. 18 AAC 50.077(k)(1), the proposed section that required registration has been renumbered and is now in the adopted regulations at: 18 AAC 50.077(h).

18 AAC 50.077 (k)(2) - (k)(4):

Comments were received regarding the requirement for professional installation for new devices and prohibiting, in new construction, that wood-fired heating devices be the only source of heat expect for dry cabins located on 2 acre parcel or larger. Comments ranged from general support to general nonsupport. Focused comments were also varied. Some commenters felt that the regulations did not go far enough and suggested that there should be no wood only primary heat source allowed within the nonattainment area. Others felt that requiring a certified wood stove installer is ridiculous and unreasonable, a political favor to wood stove retail stores, and an unnecessary cost to home building. While others felt that the requirement was absolutely necessary. Also several commenters felt compliance for this measure was very important and questioned how it would be done. Concern was also expressed regarding if there are enough of the various types of installers, the cost for installers, and why there is a requirement for certified retrofit control devices if ESPs are not part of the plan. And there was a suggestion that inspection should be required instead to allow individuals to install themselves. Also while supportive, commenters felt that additional incentives were needed to ensure alternative heat for rental units. And a commenter requested additional clarification to ensure that only one dry cabin per 2 + acre lot may have a primary solid fuel burning appliance.

Response:

Having certified wood stove installers install wood stove devices in the nonattainment area will assist in preventing emission problems and the extra costs associated with improper installation while also helping to maintain the operational lifetime of the devices. A number of other nonattainment areas have requirements that require certified wood heating professionals be used for installations, permitting, and inspections. As a result, ADEC had to consider whether these were technically and economically feasible Best Available Control Measures (BACM) that must be included in the FNSB nonattainment area. ADEC found it was technically and economically feasible to require professional installation of heating devices and retrofit devices to ensure that wood heaters can operate properly as designed. ADEC plans to rely on the National Fireplace Institute, Masonry Heater Association, or equivalent certifications for installers.

ADEC included installer requirements for retrofit devices because of the community interest in ESPs as a technology that could assist in improving the area's air quality. With ESPs becoming more prevalent in the community, it is important that they are correctly installed and operated for homeowners to gain the emission benefits from their investment in this new technology.

ADEC agreed with the request to clarify the number of 'dry cabins' that could be newly constructed with wood as primary heat and has revised the regulation accordingly.

<u>Fiscal Concerns:</u>

Some commenters expressed concerns about the cost of using professional installers. ADEC understands that some individuals may want to install devices on their own, but this would not meet the BACM requirements and can lead to improper installations resulting in higher emissions. In its analysis, ADEC did not find the use of professional installers to be economically infeasible.

<u>Department Decision</u>**:**

The Department reorganized 18 AAC 50.077 for clarity purposes. 18 AAC 50.077(k)(2), the proposed section that required professional installation and restricted wood fired devices as primary heat for new construction and non-grandfathered rentals has been renumbered and is now in the adopted regulations at: 18 AAC 50.077(i) - professional installed, and (j) new construction.

The Department further clarified the requirements for professional installers in the final regulations.

The Department clarified the requirement that for new construction wood cannot be the primary or only heat source except in a single 'dry' cabin located on a 2 acre parcel or larger. A definition was included for 'dry cabin'.

18 AAC 50.078 – Additional PM2.5 Serious Area Controls (Diesel/Commercial)

<u>Summary of Comments</u>

18 AAC 50.078(b):

<u>General Comments:</u>

Comments received on the proposed regulation revisions requiring a switch from diesel #2 to diesel #1 beginning July 1, 2020, expressed varying levels of support and concern. Some commenters noted that the department would need to educate and encourage the public for the proposed regulation to be successful. Other commenters felt that only citation authority could help enforce the proposal. Several commenters stated that the switch would create financial hardship and supply constraint. They suggested that ADEC should delay the implementation until 2024 to allow time to study the economic/market competitive impacts and gather adequate and accurate information on sulfur emissions. Some commenters argued that a switch to diesel #1 would only provide a minor decrease in PM2.5 because the heating oil, according to the State's planning inventory, is the second smallest source of PM2.5. They asserted that the data and economic analysis used at arriving at the proposed regulation are flawed. Comments also noted that the proposal would create a competition between the interior residents and the military jet requirements because diesel #1 is practically the same as jet fuel. Other commenters suggested that instead of regulating heating oil, ADEC should regulate diesel trucks and other equipment using diesel #2, as well as limit their idling time. Commenters wanted the department to consider clean burning propane and double down on the regulation of wood- and coal-heating devices.

Some commenters requested the department specify a standard fuel with a standard sulfur content according to industry standards (5000 ppm (S5000); 500 ppm (S500); or 15 ppm (S15)) and change the name of the referenced fuel from "diesel #1" to "fuel oil" to avoid confusion and additional industrial compliance burden.

Petro Star Comments:

Petro Star provided comments centered in two areas: 1) relative volumes of jet fuel grades related to aircraft emissions in the emissions inventory; and 2) data and assumptions used to estimate cost effectiveness (in dollars/ton of emission reductions) of switching to #1 heating oil in residential and commercial heating.

Responses (General Comments):

ADEC is federally required to consider all the Best Available Control Measures (BACM) from other PM nonattainment areas across the nation and one of those BACM controls is requiring the use of ultralow sulfur diesel (ULSD) containing 15 ppm S (S15) in oil-burning equipment. The federal government already has requirements for the use of ULSD in diesel powered motor vehicles, non-road engines, locomotives, marine engines, and some stationary engines. The federal rules do not apply nationally to oil-fired heating devices. In evaluating the economics of this BACM control, ADEC found that the cost differential for ULSD to Diesel #2 made that switch uneconomic. However, ADEC's economic analysis for a switch from Diesel #2 to Diesel #1 was economic. Given the range of comments received, the following list provides responses on a number of topics related to requirement for a fuel switch from Diesel #2 to Diesel #1 in the nonattainment area:

- *Public education*: ADEC agrees with the comments supporting education and compliance assistance to help individuals comply with requirements. Often, this is all that is needed to help individuals understand and comply with requirements. ADEC remains committed to working with the Borough on public education and outreach in the nonattainment area. The Division plans to conduct outreach to fuel distributors and residents on the new fuel requirements during the transition period prior to the effective date in 2022.

- *Adequate enforcement:* ADEC acknowledges the public comments that express the desire for the department to have citation or administrative penalty authority to enforce state regulations in the nonattainment area. While ADEC agrees that such authority could result in efficiencies for enforcement actions related to the programs, the power to grant this authority lies with the Alaska State Legislature, which would need to pass legislation. At this time, no legislation on this topic has been introduced for consideration. As a result, ADEC will continue to use its current civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area. The ADEC Air Quality Division has relied successfully on its current authorities in implementing the CAA programs for decades. For implementing this specific rule proposal, ADEC's experience in enforcing requirements for businesses like fuel distributors suggests that existing authorities will be both efficient and adequate for implementing this requirement.
- *Economic concerns and timing of implementation:* ADEC acknowledges that the switch from Diesel #2 to Diesel #1 has economic implications for the refineries and local residents who use #2 fuel oil to heat their homes. ADEC and UAF economists conducted an economic assessment of fuel oil switching for home heating and price elasticities using available information. However, in consideration of the comments received, ADEC is further delaying the implementation of the fuel oil switch by two years from July 1, 2020 to July 1, 2022 to address concerns about the economics and provide time to mitigate cost impacts to the extent possible. The switch from Diesel #2 to Diesel #1 will require an infrastructure change on the part of the local refinery and local fuel distribution systems and has an estimated economic impact that individuals indicated would drive more residents to using wood/solid fuel heat. With the timing of the final Serious SIP being released in the middle of the 2019/2020 heating system it would be technically infeasible to require the local refineries and fuel distributors to make this change in the middle of a heating system and given the adverse comments, a starting date prior to the 2022/2023 heating season was chosen to provide time for the local refiner and residents to prepare and budget for a switch to #1 fuel oil. The slightly longer timeframe for implementation also provides the opportunity for residents to consider and potentially take advantage of alternative fuels such as propane and the expanded natural gas service planned for the community in the coming few years.
- *Benefits of sulfur reduction from switch:* The sulfur reduction in fuel oil results in benefits because it helps to reduce the sulfate component of PM2.5 through reductions in sulfur dioxide (SO2), a precursor pollutant that forms particles in the atmosphere. The calculated emission benefits from this fuel switch are 1.92 tons/episode day for SO2. Given the magnitude of sulfate observed on the local

air monitor filters it is important to consider options for reducing SO2 emissions in the nonattainment area. Space heating sources are emitting into the breathing zone below the inversion layers on episode days and are also widely dispersed geographically throughout the nonattainment area and thus produce emissions that result in exposures over a broad area. The fuel sulfur reduction from the 2013 baseline emission inventory results in an estimated 45% reduction in SO2 emissions from space heating and would be comparable to removing all of the SO2 emissions produced by motor vehicles.

- *Competition between heating fuel and military needs:* Not all fuel oil sold in the nonattainment area is refined within the area. Fuel is already transported into the area by truck and rail to meet current market needs. By providing additional time prior to implementation, ADEC is providing refiners and distributors the opportunity to make business decision to adjust to the market change for heating oil in the context of the different types of fuel oil currently being produced and sold for military aircraft, space heating, stationary industrial sources, and transportation sources
- *Require regulation of diesel trucks and other equipment:* As described above, trucks and many other types of diesel equipment are already subject to federal requirements to burn ULSD or 15 ppm sulfur Diesel.
- *Restrict idling time for diesel equipment:* ADEC and the State Department of Transportation have worked with local trucking companies to install new technologies to allow for reduced idling of diesel trucks within the nonattainment area.
- *Focus on wood and coal heating rather than heating oil:* ADEC agrees that making reductions in wood and coal heating emissions is critically important to achieving air pollution goals in the community. However, because the area did not achieve the air quality standard and was reclassified to “Serious, ADEC is required to consider all measures implemented in other nonattainment areas, which include measures to control the sulfur content of heating fuel to reduce sulfate particulate in the area. Measures that are technically and economically feasible must be implemented in Serious nonattainment areas.
- *Consider propane for heating:* ADEC agrees that cleaner burning propane is an alternative fuel for home heating and encourages residents to consider propane and natural gas for their space heating needs, however a switch to propane would require individuals to upgrade their heating systems and goes beyond the BACM requirement addressed through the regulation of fuel oil. ADEC is supporting the use of Targeted Air Shed Grants to assist with conversion programs to any liquid fuel, including propane.
- *Fuel standard level:* Refinery industry comments suggested that the department specify a standard sulfur content that aligned with industry standards (5000 ppm, 500 ppm, or 15 ppm). ADEC agrees that using a round value for a standard would make reporting and recordkeeping easier for industry and businesses providing fuel oil to the nonattainment area. However, in order to ensure that all

in-state refiners could provide fuel oil to the Fairbanks market, ADEC chose to revise the regulation to 1000 ppm sulfur (S1000) to require a fuel sulfur standard level that is close to the current level of sulfur in Diesel #1 provided within the community. This revision aligns well with the proposed Diesel #1 fuel sulfur of 896 ppm, which was based on test data of local fuel oil.

- *Use of "diesel" vs. "fuel oil"*: Refining industry comments suggested that the term "fuel oil" is a clearer term for use in this regulatory context. ADEC agrees and has revised the final regulations to use the term "fuel oil" rather than "diesel".

<u>Responses (Petro Star Comments):</u>

Jet Fuel Grades – In the Draft SIP, ADEC had assumed a "full" transition from lower sulfur jet fuel JP4 (0.009% by mass) to higher sulfur JP8 (0.096% by mass) in 2017 based on discussions with and information provided by local military bases (Eielson and Ft. Wainwright) and Fairbanks International Airport in its estimates of jet fuel emissions within the nonroad portions of the emissions inventory. ADEC reviewed historical jet fuel volume data from 2013 through 2018 provided by Petro Star that showed that only a marginal transition to full use of JP8 occurred at the local bases in 2017. (JP8 is similar in sulfur content to Jet A commercial jet fuel.) ADEC has revised its 2013 Base Year and 2017 Reasonable Further Progress (RFP) inventories to reflect the jet fuel grade volumes provided by Petro Star.

Switch to #1 Heating Oil – ADEC reviewed historical annual heating oil sales volume data from 2013 through 2018 along with Lower Heating Value (LHV) energy content data for #2 and #1 distillate provided by Petro Star. The cost-effectiveness analysis in the Draft SIP correctly uses Higher Heating Value (HHV) energy contents of #2 and #1 heating oil from data in the local Fairbanks Community Research Quarterly published by the Fairbanks North Star Borough to translate energy demand to fuel use. (The energy demand model used within the SIP emissions inventory is calibrated based on HHV energy contents for #1 and #2 heating oil from the Fairbanks Community Research Quarterly). To calculate resultant changes in fuel volumes associated with shifting all heating oil to #1 (residential surveys estimate the current split as 68% #2 and 32% #1) ADEC revised its cost-effectiveness analysis to incorporate the LHV-based energy contents for #2 and #1 heating oil provided by Petro Star. These data reflected a 3.4% lower energy content for #1 than #2 heating oil. (Energy contents in ADEC's Draft analysis reflected a 1.6% difference in energy content.) This revision resulted in a 55% increase in the $/ton of SO_2 reduced reflected in the Draft SIP.

In response to Petro Star's comment that annual heating oil volumes are overstated within the cost-effectiveness analysis, ADEC reviewed confidential data provided by both Petro Star and Marathon (the other primary supplier of heating oil in Fairbanks). Based on heating oil volume data provided by both refiners/suppliers, ADEC determined that the estimates of 40 million gallons/year for residential space heating and 12 million gallons/year for commercial space heating used in the Draft SIP (52 million gallons/year total) were consistent with combined heating oil volumes reported by both companies within a reasonable margin of error. Petro Star provided annual data for 2013-2018; Marathon's data covered 2017 and 2018 (reflecting its entry as a supplier to the Alaskan interior). Neither company could provide clear splits of their fuel volumes sold within versus outside the nonattainment area. ADEC's estimates of heating oil volumes were based on 2011-2015 home heating surveys coupled with 2013 estimates of energy demand-based estimates of commercial heating oil usage which were then projected from 2013 to 2019 to reflect population growth. Given the differences in years and geographic areas represented, ADEC's finding that its 2019 estimates were within about 15% of the combined heating oil volumes provided by Petro Star and Marathon is a reasonable corroboration of its estimates.

Petro Star also pointed out an inconsistency in the draft cost-effectiveness analysis where combined (wood and heating oil) average daily energy use was reported as 28,887 mmBTU within one portion of the analysis spreadsheet and 13,941 mmBTU in another. The spreadsheet was reviewed and although the smaller value was listed within the cost calculation portion, it was not actually used in calculating costs of switching to #1. The cost calculations were based on <u>fuel</u> usage volumes before and after switching to #1 and not coupled to the energy use values listed in that portion of the spreadsheet. Nevertheless, the incorrectly listed value of 13,941 mmBTU in the cost portion of the spreadsheet was revised to the 28,887 mmBTU value from the emission reduction portion. But, since that energy use value was not tied to the fuel usage data within the cost calculation portion of the spreadsheet, this correction had no effect on the resultant cost-effectiveness.

Economic Costs of #1 – Petro Star commented that DEC's economic evaluation of the retail price change to switch to #1 did not evaluate supply and transportation costs.

The report titled, "*Residential Fuel Expenditure Assessment of a Transition to Ultra-Low Sulfur and High Sulfur No. 1 Heating Oil for the Fairbanks PM-2.5 Serious Nonattainment Area*," looks at incremental price differentials between fuel types in the Fairbanks area. Section 1.3 (page 14-15) of the report describes the additional fuel transportation costs (in 2015) for bringing fuel into the Interior from the Nikiski and Valdez refineries, which ranges from 18-20 cents per gallon. While limitations are noted in the report, this analysis conducted by UAF and DEC economists was based on the available data at the time.

Lack of SO_2 Precursor Demonstration – Petro Star commented about the lack of an SO_2 precursor determination that forces the state to evaluate cost-effectiveness "inequitably" under both BACT and BACM. Precursor determinations are an option provided by EPA to allow states to demonstrate that a particular precursor, in this case SO2, is not significant to the fine particulate matter levels found in the nonattainment area. Given the magnitude of sulfate observed on the local air monitor filters, it is not possible to demonstrate they are insignificant. ADEC discusses the technical challenges with conducting a sensitivity-based SO_2 precursor demonstration in Section III.D.7.8 of the SIP. As noted in the SIP, there are limitations on scientific information to support such a demonstration. Until the informational and technological limitations are addressed, the EPA requires that ADEC consider SO_2 emission reductions as significant and evaluate SO_2 emissions for BACM and BACT for all source categories per 40 CPR 51.1010(a). Model development for SO_2 and sulfate formation is an active area of research that may improve in the future. In evaluating SO_2 BACM and BACT options for the Serious SIP, ADEC considered where the emissions are occurring in the airshed as well as other source specific issues. For example, space heating sources are emitting into the breathing zone below the inversion layers on episode days, while stationary sources are emitting at higher levels above the ground. Space heating sources are also widely dispersed geographically throughout the nonattainment area and thus produce emissions that result in exposures over a broad area.

Department Decision:

ADEC continues to maintain that a switch to ULSD for home heating is economically infeasible and that the switch from Diesel #2 to Diesel #1 is economically feasible. However, ADEC revised the final regulation to allow an additional two years before implementation of the switch from Diesel #2 to Diesel #1. In response to concerns expressed from one of the refineries about the defined sulfur content of Diesel #1 in the regulation, ADEC revised the limit to 1000 ppm sulfur content (or S1000) and is using the term “fuel oil” instead of “Diesel” to reflect more standard industry language.

18 AAC 50.078(d):

Comments received on the proposed regulations requiring the commercial coffee roasters within the nonattainment area to install a pollution control device expressed varying levels of support and concern. Some commenters felt ADEC should only regulate coffee roasters that produce more than 70 tons per year (tpy) of emissions. Other commenters asked for the outright exemption of coffee roasters from the control technology requirements. Some comments noted that the thermal oxidizer is not economically feasible for all sizes of coffee roasters. They said opacity standard should be considered a regulatory control. Commenters also requested more data to better understand the source category and the cost-effectiveness of the control technology.

Response:

Under federal rules, ADEC was required to look at all the Best Available Control Measures (BACM) for PM2.5 from around the nation and determine whether they were technically or economically feasible for implementation in the nonattainment area. All other nonattainment areas with coffee roaster control measures, have a threshold that exempt small roasting units from control requirements. The most restrictive (BACM) level of control was established by the San Diego Air Quality Management District which controls all coffee roaster units with throughput of 11 pounds of coffee per hour or more. In reviewing coffee roaster controls, ADEC found that emission controls are technologically feasible and that at least one roaster in the local area had controls installed. The proposed regulation reflected that understanding, but provided an opportunity for coffee roasters to individually make the case for technological or economic infeasibility.

Based on public comments and data received from local coffee roasters, ADEC agrees that it is apparent that requiring control technology is economically infeasible for small roasters within the nonattainment area and as a result, the final rule includes a threshold to exempt small roasters while still requiring further analysis or control of larger roasters. In setting the threshold, DEC looked at the San Diego threshold as the BACM level of control and converted it to an equivalent PM emission limit of 24 pounds per year. This PM emission level corresponds to 11,440 pounds or 5.72 tons of coffee roasted per year. Coffee roasters producing less than this amount would be excluded from the control requirements of 18 AAC 50.078(d). These small operations would still be subject to 20% opacity/visible emission limits.

Department Decision:

ADEC revised the proposed regulation to include an emission threshold of 24 pounds of PM per year to exempt small coffee roasting units from having to either submit a technical or economic infeasibility demonstration or install a control device.

18 AAC 50.078(e):

Comments received on this section of the proposed regulation requiring non-commercial wood sellers to sell dry wood only were very few and consisted of a mixture of support and concern. Some commenters stated that the regulation would raise the cost of wood. Other commenters wanted the “non-commercial wood sellers” in the proposed regulation to be changed to “non-commercial firewood sellers” for the sake of clarity. Comments noted that the success of the regulation depends on citation authority and an increase in compliance staff.

Response:

ADEC acknowledges that dry wood currently costs significantly more to purchase than wet wood within the nonattainment area. ADEC estimates that 60% of residents burning wood cut their own supply and thus this measure would only impact costs for the remaining residents that purchase wood. There is potential that as a result of increased costs for purchasing wood, more residents may choose to cut their own wood or they may choose to seek to convert out of wood heating to a non-solid fuel heating alternative through the FNSB change out and conversion program. There is also the potential that, depending on the mechanism chosen to provide dry wood, the dry wood cost could normalize and potentially result in a smaller cost deferential. ADEC has provided time until October 2021 for both wood sellers and purchasers to plan and budget ahead to meet their own specific situation with respect to ensuring a dry wood supply.

Regarding the issue of confusion between non-commercial wood seller and non-commercial firewood sellers, ADEC already defines commercial wood seller in this manner in existing regulation at 18 AAC 50.076(h). However, ADEC will consider in future regulation packages whether additional clarification is helpful.

While ADEC agrees that citation authority could result in efficiencies for enforcement actions, the power to grant this authority lies with the Alaska State Legislature, which would need to pass legislation. At this time, no legislation on this topic has been introduced for consideration. As a result, ADEC will continue to use its current civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area. The ADEC Air Quality Division has relied successfully on its current authorities in implementing the CAA programs for decades. ADEC is committed to funding and implementing the measures included in the Serious SIP. The ADEC budget is determined annually by the Alaska State Legislature and the Division relies on a mix of federal and state general fund revenue to operate this program. The Division of Air Quality is prioritizing work to ensure efficient and effective implementation of all committed measures and will continue to do so.

Fiscal Concerns:

Concerns related to increased costs for dry wood are addressed above.

Department Decision:

Rather than finalizing this regulatory provision within 18 AAC 50.078, the department has added this provision to the existing section of the regulations that addresses solid fuel-fired heating device fuel requirements. The new subsection for non-commercial wood sellers is found at 18 AAC 50.076(e).

18 AAC 50.079 - Coal Fired Heating Devices

Summary of Comments

18 AAC 50.079(f):

Comments received on the proposed regulation revisions requiring the removal or replacement of an existing coal-fired device by the earlier of December 31, 2024, or the sale or conveyance as part of an existing building expressed varying levels of support and concern. Some commenters felt the proposed removal date should be earlier than December 31, 2024, as the use of the devices impact health negatively. They stated that the removal date should be within one year since the proposed switch date to heating oil #1 is 2020. Commenters argued that the banning or removal of coal-fired heating devices would improve the air quality in the area and reduce the healthcare costs for the affected individuals. Other commenters stated that the proposed regulation would create an economic hardship, particularly for elders who may not have the means of acquiring new heaters. They advised that instead of banning heating devices based on their fuel type, ADEC should treat them equally based on their emission rates per unit of energy. Some commenters suggested the department, as well as UAF and Ft. Wainwright, should explore the new coal technology – chemical looping – which allows clean coal burning.

Response:

ADEC agrees that making reductions in coal heating emissions is critically important to achieving air pollution goals and consequently, help in reducing healthcare costs of individuals in the community. However, ADEC believes that the required date of removal, December 31, 2024, would give the homeowners and real estate owners enough time to plan and make decisions. As for elders who may not have the means of acquiring new heaters, they may apply for the NOASH, other waiver programs, or choose to participate in the wood stove change-out or conversion programs.

Regarding the equal treatment of heating devices, federal certification processes treat solid-fuel burning differently and the differences are often times dependent on how a device is manufactured for use versus how it is tested for certification. In addition, emission rates per unit of energy are based on the amount of fuel that is used in the device, whereas emission rates per hour focus on what is coming out of the stack. Using emission rates per unit of energy does not cap overall emission from a single residence because of the variation of fuel used. However, the use of emission rates per hour does allow emissions to be capped.

The ADEC budget is determined annually by the Alaska State Legislature and the Division relies on a mix of federal and state general fund revenue to operate this program. Hence, the Department may not be able to explore the new coal technology for now. However, the Air Quality Division of ADEC is supporting the use of Targeted Air Shed Grants to assist with conversion programs to a variety of efficient and certified home heating appliances.

Fiscal Concerns:

Comments that raised cost concerns are addressed above.

Department Decision:

ADEC made no substantive changes to the proposed revisions to 18 AAC 50.079 based on public comments received.

18 AAC 50.990 - Definitions

Summary of Comments

One commenter supported the addition of new definitions in 18 AAC 50.990.

Response:

ADEC appreciates the comment.

General Proposal Comments By Topic

Summary of Comments

General Comments

Comments received in response to the proposals for changes to regulations governing the Serious nonattainment area for $PM_{2.5}$ NAAQS standards in Fairbanks North Star Borough (FNSB) represented the views of the public, businesses, and special interest groups. Comments were submitted via email, Air Online Services comment system, oral testimony, and in writing. General comments are categorized and summarized as follows:

- **Need for Changes to Regulations**

Commenters were divided on the need for changes to regulations governing the Fairbanks Serious nonattainment area. Those who supported the changes stated that the $PM_{2.5}$ problem in the area has been persisting for a long time and that four years is too long for the replacement or removal of uncertified wood stoves. They said that any delay in the attainment of the $PM_{2.5}$ standard and the submittal of the Serious SIP might result in the loss of the highway funds. Comments also suggested there should be a total ban of all the coal- and wood-fired devices (except emission-compliant wood pellet stoves). Some commenters stated the department should have included several Most Stringent Measures (MSM) in the proposals. Commenters who opposed the changes stated that the proposals are too extreme, unfair, and unrealistic. They argued that the proposed regulations would create an economic burden on the community. Comments also noted that nature is mostly responsible for the air pollution in the area. Commenters stated that with the progress that has been made thus far on the reduction of $PM_{2.5}$ emissions in the area, there should not be additional regulations. They also suggested that the department should propose anti-idling regulations in lieu of the wood stoves regulations.

Response:

The comments received regarding the need to change regulations illustrates the wide range of viewpoints within the community. ADEC drafted the regulations based on the local Stakeholder recommendations and the framework required by the Clean Air Act and tried to find a balance between all the dissenting opinions.

- *Total ban on all coal and wood fired devices* - ADEC does not feel that a total ban is in the best interest of the community due to the arctic environment and the lack of affordable clean energy that will ensure adequate heat without fear of property damage or loss of life.
- *Should include Most Stringent Measures (MSM)* - In the SIP several measures in the BACM analysis were identified as MSMs. Those control measures were incorrectly identified as MSM, and are now identified under technical dismissal in the BACM crosswalk in the Control Measure Chapter due to the inability to implement the measures in whole or in part within the required timeline. The BACM analysis in the Appendix III.D.7.07 has also been modified to incorporate these revisions. ADEC focused on a balanced approach to implementing

measures. All the required measures are being implemented. And all measures not implemented with the Serious SIP, must be re-examined for the 5 Percent Plan.

  - *Economic Burden* – ADEC acknowledges the concerns regarding economic burden to residents. All attempts have been made to lessen the potential burdens as much as possible. However, getting the area into attainment will have a cost associated with it.
  - *Nature is responsible for the air pollution in the area* – ADEC acknowledges that weather patterns, such as inversions, do contribute to the area exceeding the health based standard. Inversions alone, however, are not the problem. The human caused pollution from combustion sources near ground level only continues to build during an inversion. Therefore, the focus is on the human-made pollution.
  - *Progress is already being made, no additional regulations needed* - ADEC agrees that progress is being made in reducing PM2.5 concentrations within the nonattainment area. However, when the Environmental Protection Agency (EPA) reclassified the area as a Serious Nonattainment Area it triggered a number of new more stringent requirements. States developing Serious Air Quality Plans must review controls from all other areas throughout the United States and implement all controls found unless it can be documented that a control measure is technically or economically infeasible. A measure may also be removed if a current regulation is more stringent. The new requirements proposed are those remaining measures that could assist the area in coming into attainment which could not be documented as technically or economically infeasible.
- *Anti-idling regulations* – Rather than establishing new regulations that may not result in significant quantifiable PM emission reductions, ADEC and the State DOT have worked with local trucking companies to install new technologies to allow for reduced idling of diesel trucks within the nonattainment area.

<u>Department Decision:</u>

After careful consideration and in order to meet federal requirements, ADEC is continuing with the proposed regulations with some modifications as described in other sections of this document.

- **Impacts of Air Quality on Health**

Many of the comments asserted that the high levels of PM2.5 in the Serious nonattainment area pose serious health risks to children and sensitive populations as well as every other persons living in the community. Among the health conditions associated with short-term increases in particulate pollution, as noted in many of the comments, are cardiovascular disease, strokes, congestive heart failure, asthma attack, diabetes, and inflammation of lung tissues. Some commenters stated that the air quality problem in the area had aggravated the health conditions of their families. They claimed their healthcare costs had increased tremendously over the years. A few commenters, however, dissented, arguing that the research connecting $PM_{2.5}$ with health issues and premature health is based on falsified science.

Response:

ADEC understands the comments and concerns expressed about the health impacts and associated costs that result from exposures to high levels of PM2.5. The regulation of PM2.5 and other pollutants by the EPA and ADEC in the State is to prevent public health issues including stroke, kidney diseases, lung and heart complications, which may arise from the inhalation of $PM_{2.5}$ pollutants. The SIP itself is meant to reduce air pollution to healthy levels and gain health benefits for individuals in the community.

ADEC appreciates the sentiments of those that disagree with the science of PM2.5. However, results from several epidemiologic studies, both locally and internationally, have implicated PM2.5 as a risk factor for cardiovascular diseases, congestive heart failure, stroke, asthma, and other respiratory diseases, especially in sensitive subgroups. Below listed are some links with evidence:

https://www.lung.org/our-initiatives/healthy-air/outdoor/air-pollution/particle-pollution.html

https://www.cdc.gov/air/particulate_matter.html

https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4740125/

https://www.who.int/airpollution/household/health-impacts/en/

- **Need for Citation Authority**

Many of the comments received on the proposals emphasized the need for citation authority. Commenters stated that unless ADEC acquired citation authority, the proposed regulations would not be effective. They stated that fines and voluntary actions had yielded no positive impacts in the past. Some comments even suggested that curtailment violators should be banned from using wood stoves. Other commenters noted that ongoing communication with the education of the public is the only effective solution to the air quality problem in the area. They stated that the inclusion of science-based educational program in the curriculum would help enlighten children and their parents about air pollution and its impacts. Comments added that the department should continue with the Split, Stack, and Store Program. Commenters also noted that the idea of ADEC entering homes of people to enforce regulations would be invasion of privacy.

Response:

Adequate enforcement: ADEC acknowledges the public comments that express the desire for the department to have citation or administrative penalty authority to enforce state regulations in the nonattainment area. While ADEC agrees that such authority could result in efficiencies for enforcement actions related to the programs, the power to grant this authority lies with the Alaska State Legislature, which would need to pass legislation. At this time, no legislation on this topic has been introduced for consideration. As a result, ADEC will continue to use its current civil and criminal enforcement authorities to enforce air quality requirements within the FNSB nonattainment area. The ADEC Air Quality Division has relied successfully on its current authorities in implementing the CAA programs for decades.

Public education: ADEC agrees with the comments supporting education and compliance assistance to help individuals understand the importance of reducing air pollution in the community. Often, education and outreach is all that is needed to help individuals understand and comply with requirements. ADEC's website contains information and outreach materials on a number of topics relevant to addressing air pollution in the nonattainment area. For example, the Division's "Burn Wise Alaska" web site (https://dec.alaska.gov/air/burnwise/) contains much valuable information on best burning practices. The ADEC cannot require science-based education curriculum in public schools, but the Division does work to find opportunities to interact with children to discuss air pollution and has developed an activity book for children on wood burning issues. ADEC remains committed to working with the Borough and other organizations in the community on air pollution related public education and outreach in the nonattainment area.

- **Monitoring**

Some commenters stated that the department should make the daily readings of $PM_{2.5}$ concentration available to the public. They also stated that the graphical illustration of at least four years of $PM_{2.5}$ data for each of the six winter months should be provided for people to compare. Other commenters felt that monitor readings should be used for warning the public and not for regulatory purposes. They argued that monitors do not function very well during cold winter months. Some commenters suggested that the department should make efforts to monitor the $PM_{2.5}$ emissions that come from outside into the nonattainment area.

Response:

- Data Accessibility: ADEC's website provides access to the monitored PM2.5 concentrations.
  - A Street: http://dec.alaska.gov/Applications/Air/airtoolsweb/Aq/Station/42
  - NCore: http://dec.alaska.gov/Applications/Air/airtoolsweb/Aq/Station/17
  - Hurst Road: http://dec.alaska.gov/Applications/Air/airtoolsweb/Aq/Station/20

  Additionally, the Air Quality AQI page has a data download feature at the bottom of the page by clicking "Downloadable Data Reports". This feature allows download of several months of unverified raw data.

- Graphical Display of Monitoring Data: Annual data graphs for the Fairbanks State office Building (SOB) and NCore sites are available for the years 2000 through 2018. Scroll down past the design value trend graph to see the yearly graphs: http://dec.alaska.gov/air/air-monitoring/community-data/fnsb-fairbanks-pm25-data

  Hurst Road $PM_{2.5}$ annual data graphs are available for the winters of 2012 through 2018). Scroll down past the design value trend graph to see the yearly graphs:

http://dec.alaska.gov/air/air-monitoring/community-data/fnsb-northpole-pm25-data

DEC is currently considering improved methods of displaying data on its website.

- Use of Monitoring Data for Warning Public: The purpose of posting Met One BAM $PM_{2.5}$ data on the real-time website is expressly for the public to use to plan their activities and minimize health impacts. This hourly data is not used for regulatory purposes. DEC's meteorologist inputs the hourly data into a prediction model that he uses along with meteorological models to issue advisories and episodes for FNSB during the winter. The data DEC uses for regulatory purposes are collected daily on filters using Thermo Fisher (formerly Rupprecht and Patashnick) Partisol 2000i and 2025i samplers.

- Cold Weather Monitor Performance: These samplers were designated as federal reference method (FRM) regulatory monitors in 1998 and have been used successfully in northern climates for two decades, including the past two winters in Fairbanks.

- Emissions from Outside Area: The emissions from outside the area for Eielson Air Force Base and Healy are included in the model and the emissions inventory. During the typical high PM2.5 days, the wind speed is near zero and strong inversions are present, preventing the circulation of emissions from outside the area from having an impact on the nonattainment area. Emissions that may enter the nonattainment area from international transport are captured in the model as background concentrations and they are called boundary conditions.

- **Need for Regional Kiln**

Some commenters noted that access to forest-killed wood and spruce beetle-eaten wood would increase the availability of dry wood. Many of the comments received highlighted the need for regional kilns. Commenters stated that only regional kilns can provide a consistent supply of dry wood in the area.

Response:

ADEC staff currently works with wood sellers to confirm dry wood stands as part of the existing moisture content disclosure program, but the agency does not have the programs or authority to open up additional stands of beetle-killed or fire-killed timber for wood cutting.

ADEC agrees that wood-drying kilns or a wet for dry wood exchange program could be viable options for wood sellers and individuals to efficiently dry wood in shorter periods of time. ADEC is not requiring the construction or use of kilns or implementation of wood exchange programs through the SIP, but that does not prevent local businesses or residences from implementing these ideas. ADEC does not have the resources to incentivize or support the construction of kilns or implementation of a wood exchange program.

- **Electrostatic Precipitators (ESPs)/Retrofit Devices as Curtailment Waivers**

Some of the comments received on the proposals requested the department to exempt any EPA-certified wood stoves paired with electrostatic precipitators or retrofit devices from curtailment. Other commenters wanted ADEC to be more explicit on the NOASH exemption/waivers.

Response:

ADEC appreciates the community interest in ESPs as a technology that could assist in improving the area's air quality. Until there is additional data, however, ADEC is limited in its ability to provide regulatory incentives to using the devices.

Department Decision:

In response to comments received, ADEC has added to the waiver tables found in the Episode Plan the ability to provide extended waivers to those who have added an ESP to their wood stove and that otherwise qualify and apply for NOASH and Stage 1 waivers.

Related Comments Outside of Scope of Proposal

A few of the comments received were outside of the scope of proposal.

- Some commenters suggested that ADEC should focus more on indoor air quality than they do on outdoor air quality. They stated that the indoor air quality is worse and more dangerous during winter because people stay indoors and burn wood to keep themselves warm.
- Some commenters stated that the nonattainment boundary is arbitrary and includes areas without air quality issues. They suggested the removal of Goldstream zone, higher elevations, and other rural areas from the nonattainment boundary.
- A commenter requested that ADEC should quantify solar radiation management (SRM) activities in Fairbanks region. He asserted that the aerosolized micro-particles released into the air space by jet tankers and passenger aircrafts contribute to particulate loading and exacerbate cardiac and pulmonary risks more than wood smoke does.
- Another commenter stated that a mixture of 20% biodiesel and 80% petroleum diesel can reduce carbon dioxide, carbon monoxide, sulfur dioxide, particulate matter, hydrocarbons, and air toxins.

Response:

While no changes were made to the regulations or SIP as a result of these comments, ADEC provides the following responses for information purposes:

- State statute AS 46.14.900 places limits ADEC's jurisdictions and authorities with respect to indoor air.
- EPA determines the nonattainment boundary for the nonattainment area. Information on the designation process for the PM2.5 nonattainment area can be found on EPA's web site at: https://www3.epa.gov/pmdesignations/2006standards/index.htm.

- ADEC included aircraft emissions in the Serious SIP. The majority of the emissions from aircraft occur above the inversion layer, but emissions are included in the air modeling for the SIP.
- ADEC did not propose any biofuel requirements in the state regulation or air quality plan as it has not been used to control particulate matter in other communities. However, ADEC will take that input for consideration for research in future planning efforts.

Public Review Process Comments

A few of commenters expressed that they feel like the Department will just review public comments as required but will not actually address them and feel that the public engagement process was insufficient. Other commenters support the Department's efforts to protect the air and the public engagement process. One commenter opposes the requirement that sellers sell only "dry" wood and states that more dry wood would be burned if there were subsidies for wood sheds or a reward program for people who maintain a large supply of dry wood. One commenter also stated that residents who continue to burn uncertified devices or burn during alert days should be fined or lose the right to use wood stoves.

> Response:
>
> ADEC reviewed all public comments and made some adjustments to the final Serious SIP and regulations based on the input received. ADEC's public engagement process for this regulation package went beyond the minimum requirements set out in state statute, with department staff holding an open house, public hearing, presenting at a local Borough assembly work session, and making themselves available at a variety of meetings with community organizations and stakeholders.
>
> Responses to comments on dry wood programs and enforcement may be found in earlier sections on those topics.

Fiscal Concerns Comments

Comments about Costs To Public:

Commenters provided comments on a number of fiscal issues. Commenters overall supported the Department's finding that ultra low sulfur diesel is economically infeasible. Many commenters are concerned about the increased costs to the public of the proposed regulations. The concerns included requiring consumers to switch to more expensive #1 diesel from #2 diesel. Commenters expressed concerns that the Department needs to have a better understanding of the market availability of fuels and whether there will be sufficient supplies of #1 diesel to meet the timeline for switching. Some recommended a delay to 2024 for implementing the fuel switch requirement. They stated that if there is insufficient #1 fuel available for home heating needs, costs to consumers may increase and the decreased supply of #1 diesel could result in additional wood burning. Some commenters specifically stated that if only #1 diesel is allowed, they may start cutting and burning wood. Commenters also noted that some people can already barely afford to heat with wood and if they are forced to switch to liquid fuel heating options, they will not be able to afford to keep their homes warm. Additionally, there is concern that if people are forced to move to pellet stoves or other heating sources that require electricity to work, they will be unable to heat their homes in case of power outages. Commenters were concerned that the increased costs will lead to many residents being forced to move away due to not being able to afford to live in the Fairbanks area.

A number of commenters stated that they felt that the Department had used inaccurate or inconsistent calculations to determine the impacts of the proposed changes on consumers and that using the information they provided would show that the costs to consumers would be much higher than estimated.

Response:

ADEC recognizes that the Serious SIP and associated regulations impose additional burden on local residents and businesses. The department has carefully considered costs and economic data provided by individuals and businesses in finalizing the regulations and plan. The department has worked to mitigate cost impacts to the extent possible while still meeting federal requirements.

ADEC acknowledges that the switch from Diesel #2 to Diesel #1 has economic implications for the refineries and local residents who use #2 fuel oil to heat their homes. ADEC and UAF economists conducted an economic assessment of fuel oil switching for home heating and price elasticities using available information. However, in consideration of the comments received, ADEC is further delaying the implementation of the fuel oil switch by two years from July 1, 2020 to July 1, 2022 to address concerns about the economics and provide time to mitigate cost impacts to the extent possible. The switch from Diesel #2 to Diesel #1 will likely require an infrastructure change on the part of the local refinery and local fuel distribution systems and has an estimated economic impact that individuals indicated would drive more residents to using wood/solid fuel heat. With the timing of the final Serious SIP being released in the middle of the 2019/2020 heating system it would be technically infeasible to require the local refineries and fuel distributors to make this change in the middle of a heating system and given the adverse comments, a starting date prior to the 2022/2023 heating season was chosen to provide time for the local refiner and residents to prepare and budget for a switch to #1 fuel oil. The slightly longer timeframe for implementation also provides the opportunity for residents to consider and potentially take advantage of alternative fuels such as propane and the expanded natural gas service planned for the community in the coming few years.

Comments about Need for Resources:

Numerous commenters stated that the Department needs additional staffing and/or funding in order to adequately ensure compliance with the proposed regulations. They recommended that the Department ask the Governor and Legislature for additional resources to carry out the tasks required.

Response:

ADEC is committed to funding and implementing the measures included in the Serious SIP. The ADEC budget is determined annually by the Alaska State Legislature and the Division relies on a mix of federal and state general fund revenue to operate this program. The Division of Air Quality is prioritizing work to ensure efficient and effective implementation of all committed measures and will continue to do so.

Comments about Costs to Industry:

Woodstove manufacturers commented that the testing requirements for woodstoves would be very costly for the manufacturers as well as consumers and would result in fewer choices for consumers as well as increased costs for industries such as construction.

Response:

In response to concerns surrounding additional testing costs for wood heater manufacturers, the department revised its final regulations to allow for the use of certification test data required under the federal program to meet state requirements. The department also provided additional time before the testing data would be required for use on the department's certified device list to allow manufacturers the time to complete national Step 2 certification testing for their devices in the coming year.

A coffee roaster commented that control technology is likely to be economically infeasible for at least some of the roasters in the non-attainment area, due to their size. Commenters stated that overall the coffee roasters should be exempt from control regulations until more data is available.

Response:

ADEC agrees that control technology may be economically infeasible for small roasters within the nonattainment area and has included a threshold in the final regulations to exempt small roasters. All other nonattainment areas with coffee roaster control measures, have a threshold that exempt small roasting units from control requirements. The most restrictive (BACM) level of control was established by the San Diego Air Quality Management District which controls all coffee roaster units with throughput of 11 pounds of coffee per hour or more. DEC looked at the San Diego threshold and converted it to an equivalent PM emission limit of 24 pounds per year. This PM emission level corresponds to the production of 11,440 pounds or 5.72 tons of coffee roasted per year. Coffee roasters producing less than this amount would be excluded from the control requirements of 18 AAC 50.078(d). These small operations would still be subject to visible emission limits.

A number of commenters stated that the economic infeasibility findings of the Best Available Control Technology (BACT) analysis that is being applied to larger point sources should also be applied to other point source categories in the non-attainment area.

Response:

ADEC appreciates the suggestion of economic infeasibility findings for all the point sources in the non-attainment area. However, there are specific CAA requirements regarding the selection of BACT and findings of economic infeasibility for different categories of point sources. BACT determinations must be made on a site and unit specific basis. ADEC worked through the stepwise BACT methodology for each stationary source and its emission units individually using available information.

Chena Power Plant Response to Comments

Table of Contents

[why does header have two different dates?]

1. Aurora Energy, LLC.

a. General Comments

Note: Aurora Energy comments not related to BACT were summarized and addressed previously in the corresponding sections of the Response to Comment document.

Aurora Energy Comment (1):

Per the Clean Air Act (CAA), the Serious SIP was supposed to be submitted on December 31, 2017 to describe the Best Available Control Measures (BACM) bringing the area into attainment by December 31, 2019. The 2016 $PM_{2.5}$ Implementation rule allows states to request a 5-year extension of the attainment date (i.e., December 31, 2024) as part of the Serious SIP if attainment is not anticipated by December 31, 2019. Within the 5-year attainment date extension request, the state would outline Most Stringent Measures (MSM) to be applied towards bringing the area into attainment by December 31, 2024. However, if a request is not accepted by the EPA and the area does not meet attainment by the Serious Area attainment date (December 31, 2019) then the Clean Air Act is prescriptive and requires a plan to reduce the concentration of $PM_{2.5}$ by five percent annually. A plan is to be submitted one year after the attainment date (i.e., December 31, 2020) with details on how a 5% annual reduction will be achieved. What has been communicated through the Serious SIP draft is that the most expeditious attainment date for the area is 2029.

Aurora Energy Comment (2):

5% Reduction Plan

Issue: The DEC is required to submit a 5% reduction plan by December 31, 2020 which hasn't been communicated to the community and/or industry.

Request: As soon as practical, communicate the details of the plan to industry and the community.

Background:

The details of a 5% plan, or at least the outline of such a plan should be better communicated with the community. There is a lack of clarity in what measures the plan would propose. The assumption is the 5% plan will be more stringent than what is being proposed within the Serious SIP.

Response:

The 5% plan was presented as an option if the extension request is not sufficient and this *requires attainment by 2024. Since, the controls currently applied in the Serious SIP will not satisfy the extension and attainment by 2024, the 5% plan is the next step. The 5% plan option was presented to the FNSB assembly and community during the public comment period, May-July 2019, and was again presented to the FNSB assembly and at a public panel discussion in North Pole on September 18th, 2019.*

Aurora Energy Comment (3):

Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC 50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.

Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[2] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[3] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II

[2] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.

[3] Section 7.7.5.1.2 “Device Requirements – wood-fired and coal-fired standards”, Draft Serious SIP.

auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient.

Ranking among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; 0.06 lbs/MMBtu[heat output basis]) were consistent with EPA Certified Woodstoves (0.041 g/MJ; 0.10 lbs/MMBtu [heat output basis]).[4] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

Aurora Energy Comment (4):

Operational Requirements

Issue: The regulation isn't clear as to whether testing can be done with retrofit control devices on non- qualifying solid fuel heating devices to demonstrate qualifying emission rates. Retrofit control devices can reduce pollution emissions significantly. Use of the devices in the nonattainment area should be incentivized.

Request:

- Clarify within the regulations that emissions testing with retrofit controls can be used to qualify the emissions from solid fuel burning devices.
- The use of retrofit control devices, provided significant reductions in emissions were demonstrated, should be incentivized through an exemption for the use of the solid-fuel heating device with retrofit controls during curtailment periods.
- Suggest a lower emission standard which would qualify the use of solid fuel burning devices during curtailment periods.

Background:

The DEC is imposing curtailments for non-exempt devices during emergency episodes. Ideally, if studies associated with retrofit control devices were to demonstrate significant reductions in pollutant emissions, it would seem appropriate to establish emission rates (i.e., 0.10 lbs/MMBtu or less) and allow for the operation of certain devices that have retrofit controls without curtailment during episodes.

[4] OMNI-Test Laboratories, Inc. 2011. Measurement of Space-Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space-heating-study-fairbanks-draft-report-rev-4.pdf

Aurora Energy Comment (5):

Small Area Sources

Issue: Coffee roasters are required to put emission controls on their processes and small area sources are asked to submit information.

Request:

Remove the provision requiring coffee roasters to have emission controls.

Establish a significant level for small area sources similar to major source requirements. That is, require emission controls only if the sources are emitting greater than 70 tpy of the nonattainment pollutant or its precursor and are demonstrated as being significant contributors to the nonattainment area.

Background: The department is considering pollution control devices on small area sources, namely coffee roasters. The application of pollution control is requested even though there are no regulations governing coffee roasting as a source of pollution nor is there any justification indicating that coffee roasting has some significant impact on the fine particulate concentration in the area. Under the Clean Air Act and 2016 $PM_{2.5}$ implementation rule, major sources which emit greater than 70 tons per year of fine particulate matter or its precursors have the ability to show insignificance to the area problem through precursor demonstrations and can be exempt from the application of BACT. Not to mention, if a major source curtails their emissions to less than 70 tons per year, the source doesn't have to participate in any control technology assessment or application. Unless there is some reason to believe that 'coffee roasting' by individual roasters are emitting more than 70 tons of $PM_{2.5}$ through their process, then there is no justification for applying control technologies on those sources. The state is currently asking for information from other small area sources, such as charbroilers, incinerators, and waste oil burners. Industrial activities like incinerators and waste oil burners are subject to the state regulations. If the activity is an insignificant unit, or insignificant on an emission rate basis, category basis, or size and production rate basis as described in the state regulations under 18 AAC 50.326 (d) – (g) or the activity is not required to apply for a Construction Permits under 18 AAC 50.302, there should be no requirement for the small commercial activities unless it is known that they are contributing significantly to the problem. Suggested significance should be defined as the impact of the source to $PM_{2.5}$ concentration within the nonattainment area (i.e., 1.5 $\mu g/m^3$) consistent with the 2019 $PM_{2.5}$ precursor demonstration guidance.

b. Best Available Control Technology

Aurora Energy Comment (6):

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010(3). The economically infeasible consideration is discussed later within these comments, however, a technologic infeasibility case could be considered due to the impending deadlines and the actual time it would take to design, build and implement SO_2-BACT for any facility. A cleaner approach to major source BACT would be to determine that SO_2-BACT for the community of major sources is not economically feasible. If that approach is accepted by the EPA, no further consideration would be necessary for BACT.

The ADEC has provided a BACT analysis for the Chena Power Plant (CPP) and other major sources within the nonattainment area. A top-down approach was used for the FNSB stationary sources. Aurora is providing additional information to better characterize the CPP within the context of a BACT analysis. Aurora is providing an updated emission rate, justification for technically infeasible controls for NOx, and updated capital cost for Dry Sorbent Injection (DSI). Lastly, Aurora is providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

Response:

The Department has not taken the approach suggested by the Commenter related to conducting an economic feasibility determination for the community of stationary sources. Rather, the Department conducted BACT Determinations for each individual stationary source located in the Serious nonattainment area.

Per federal requirement, DEC evaluated all point sources with emissions greater than 70 TPY of PM2.5 or for any individual PM2.5 precursor (NOx, SO_2, NH_3, VOCs). These units are subject to site-specific review for BACT. A BACT limit is a numerical emission limit that is needed for each emission unit for each pollutant subject to review. The limit must be met on a continual basis; specify a control technology or work practice; include an averaging period; and be enforceable as a practical matter. BACT analyses are detailed in the BACT Determinations and the Control Strategies chapter of the SIP.

Aurora Energy Comment (7):

SO_2 and NOx emission rate

Issue: The current emission rates used by ADEC within the SIP for Aurora are not representative.

Request: Update the SIP to reflect the most current emission rates of 0.131 lbs-SO2/MMBtu and 0.359 lbs-NOx/MMBtu as demonstrated by the source test conducted in July of 2019.

Background:

Aurora's current emission rates for SO_2 and NOx referenced by the ADEC for the purposes of BACT and probably the emission inventory within this draft SIP are 0.472 lbs-SO_2/MMBtu and 0.437 lbs- NOx/MMBtu. According to the DEC, these emission rates are taken from a 2011 source test; however, those emission rates are inconsistent with the emission rates associated with the 2011 source test which are 0.398 lbs-SO_2/MMBtu and 0.371 lbs-NOx/MMBtu (See Table 1). In October 2018, Aurora conducted a source test to update the SO_2 and NOx emission rates for the CPP. The emission rates derived were 0.258 lbs-SO_2/MMBtu and 0.346 lbs-NOx/MMBtu. This test was invalidated by the DEC.

Table 1: SO_2 and NOx emission rate from November 11, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	134.3	1.66E-07	7.5E-06	9739	9.5	0.398
Nitrogen Oxide	174.0	1.194E-07	2.1E-05	9739	9.5	0.371

Subsequently, a new source test was conducted with the intent of using the information within the Serious SIP for the BACT analyses, emission inventory, and modeling. Aurora has coordinated with the DEC in order to have a representative source test to better characterize the emissions from the facility. The source test was performed on July 12, 2019 and evaluated SO_2 and NOx emissions while using representative coal. The three year average coal-sulfur content was evaluated for the period July 1, 2016 through June 30, 2019 to determine the representative coal-sulfur content. The coal-sulfur content mean was 0.12%.The source test plan was approved by the department. Representatives from the department were on-site to verify the source test, the coal feed rate, and used the department's portable monitor to measure SO_2, NOx, and other constituents during the source test.

Although the results indicated within this document are preliminary, once the source test report is finalized, it will be submitted to the DEC for approval. As mentioned, the intent of the source test is to better characterize the emissions from the CPP to use in applications within the Serious SIP like the BACT analysis, emission inventory, and modeling. The new emission rate in lbs/MMBtu of the respective pollutants are 0.131 lbs-SO_2/MMBtu and 0.359 lbs-NOx/MMBtu based on EPA Method 19 and are listed in Table 2 below:

Table 2: SO_2 and NOx emission rate from July 12, 2019 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	45	1.66E-07	7.5E-06	9780	9.2	0.131
Nitrogen Oxide	172	1.194E-07	2.1E-05	9780	9.2	0.359

Provided for reference are the emission rates derived for the CPP during the October 27, 2018 source test (See Table 3). This emission rate was used in the Emission Inventory for 2018 from the facility. The test was invalidated due to a lack of representation by the DEC at the source test. The source test utilized EPA methods and an independent 3rd party source testing company to evaluate the flue gas.

Table 3: SO_2 and NOx emission rate from October 27, 2018 source testing

Pollutant	Concentration	Conversion Factor	Cd	Fd	O2 %	Emission Rate
Units	(ppm)		(lb/scf)	(scf/MMBtu)	(%)	(lbs/MMBtu)
Sulfur Dioxide	89.1	1.66E-07	1.5E-06	9776	9.2	0.258
Nitrogen Oxide	166.2	1.194E-07	2.0E-05	9776	9.2	0.346

Response:

The Department revised the baseline emission rates for NOx and SO_2 to 0.402 lb/MMBtu and 0.301 lb/MMBtu, respectively. These emission rates are the average of the two most recent approved source tests conducted on July 12, 2019 and the November 19, 2011. In calculating the average of the emission rates, the Department used 0.445 lb/MMBtu NOx and 0.471 lb/MMBtu SO_2 for the 2011 source test. These 2011 emission rates were provided to the Department both in the application for AQ0315ORL01 submitted in March of 2012 and again in the March 19, 2012 emissions fee estimate as indicated in Table 1 – Summary of Emissions Tests at the Chena Plant, November 19, 2011.

*The Commenter contends that several more recent source tests have been conducted that are more representative of actual emissions at the source. However, the October 27, 2018 source test cited by the Commenter was **not performed for any regulatory reason** as indicated in the December 26, 2018 source test report cover letter from Aurora to the Department and therefore not acceptable for calculating emissions (emphasis added).*

The Department acknowledges that the SO_2 emission rates may be lower than the 2011 tested *values and the average used in the cost effectiveness calculation in the BACT Determination. The Department intends to work with Aurora to get the most representative data moving forward to ensure that the baseline emission rates are representative of actual emissions.*

The Department notes that it does not plan to require implementation of SO_2 *controls at the Chena Power Plant due to the financial indicators provided by Aurora and allowed under Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085. The Department finds that the financial indicators provided by Aurora are sufficient evidence to demonstrate that imposing add-on DSI controls on the existing coal-fired boilers would cause an adverse economic impact to Aurora. For more information see Appendix III.D.7.7 for Aurora's November 1, 2018 response to DEC's information request.*

The Department intends to incorporate the 0.301 SO_2 *emission rate into Aurora's air quality permits to ensure the limit is federally enforceable as a practical matter. EPA has indicated its position that controls and limitations used to limit a source's Potential to Emit must be federally enforceable. See 54 FR 27274 (June 28, 1989). Generally, to be considered federally enforceable, the permitting program must be approved by EPA into the SIP and include provisions for public participation. "In addition, permit terms and conditions must be practicably enforceable to be considered federally enforceable."*

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Aurora Energy Comment (8):

Technically Infeasible Pollution Control Option

Issue: Selective Catalytic Reduction is not technically feasible at the Chena Power Plant.

Request: Reflect that SCR is not technically feasible within the BACT analysis for the Chena Power Plant.

Background: Based on an engineering study conducted by Stanley Consultants, SCR was determined technically infeasible for reduction of NOx emissions from the industrial coal-fired boilers at the Chena Power Plant.[5] The optimal location of an SCR would be downstream of the baghouse on the common stack. This arrangement would provide for a constant operating gas temperature, reduces issues associated with fouling on the catalyst and locating the SCR downstream of the catalyst would prevent poisoning by the presence of ammonium sulfates created with the injection of ammonia in the flue gas. However, the temperatures of the flue gas after the baghouse are less than adequate. A minimum temperature of 350°F is required for the SCR catalysts to function correctly. The flue gas temperature after the baghouse is

[5] Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.

approximately 310°F.

Response:

Based on review of the engineering study conducted by Stanley Consultants, the Department revised the NOx BACT Determination to indicate that SCR is not a technically feasible control technology because of the historic flue gas temperature at the Chena Power Plant. The Department reviewed past source test data which identified flue gas temperatures within the range indicated by the Commenter (i.e., around 300^{o}F), and as stated in the BACT Determination, SCR for NOx control has a narrow window of acceptable inlet and exhaust temperatures (500^{o}F to 800^{o}F). Therefore, the Department concludes that SCR is not a technically feasible control technology for the Chena Power Plant and has revised the BACT Determination and Control Strategies chapter accordingly.

The Department notes that similarly, SNCR is no longer considered a technically feasible control technology because it requires a reaction temperature window of 1,600^{o}F to 2,200^{o}F. The Department further notes that the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Aurora Energy Comment (9):

Updated Capital Cost for DSI

Issue: Capital cost for DSI as provided to the DEC was determined to be $20,682,000.

Request: Use the capital cost of $20,604,000 for DSI in the BACT analysis to determine a cost effectiveness value.

Background: A refined and final opinion of probable cost is being provided for the CPP DSI which is $20,604,000.[6]

Response:

The Department recalculated total project cost for DSI on Aurora's coal-fired boilers using the refined and final opinion of probable cost of $20,604,000. The Department notes that this change has a negligible impact on cost per ton of SO_2 removed, now calculated at $9,686/ton using the average of emission rates discussed in Response to Comment 7.

[6] Ibid.

Aurora Energy Comment (10):

BACT Cost Effectiveness Calculations

Issue: The DEC BACT cost effectiveness values in the draft SIP for the Chena Power Plant are not representative.

Request: Change the section to reflect representative cost effectiveness values based on the representative emission rates outlined below.

Background:

BACT cost effectiveness calculations were done by the DEC using established cost estimating procedures. The procedures require that inputs are adjusted to reflect the conditions of the facility assessed. Some of the key inputs identified by the DEC are as follows: the emission rate for SO_2 and NOx were 0.472 lbs-SO_2/MMBtu and 0.437 lbs-NOx/MMBtu, a retrofit factor of 1.5 was used for a difficult retrofit, an interest rate of 5.5%, and equipment life for NOx and SO_2 controls were 20 and 15 years respectively. Using the DEC inputs for wet scrubbers and SDA technologies, the cost effectiveness value and capital costs output are not consistent with the text within the draft SIP. DEC calculated the cost effectiveness for the installation of wet scrubbers and SDA to be $10,620/ton and $11,298/ton. When the DEC inputs were used within the spreadsheets, the cost effectiveness values for the installation of wet scrubbers and SDA were $14,572/ton and $15,726/ton (See Table 4 - values in parentheses) respectively. However, when the emission rate was updated in the spreadsheets to the representative emission rate from the July 12, 2019 source test (0.131 lbs-SO_2/MMBtu), the cost effectiveness value increased to $49,585/ton for wet scrubbers and $53,909/ton for SDA. Using the DEC's spreadsheets for DSI cost effectiveness, Aurora adjusted the capital cost of DSI from $20,682,000 to $20,604,000 based on refined opinion of probable cost and used the updated emission rates referenced in Table 2. The cost effectiveness value for DSI increased from $7,495/ton to $18,007/ton (Table 4).

Table 4: Updated Cost Effectiveness Value based on SO_2 and NOx Representative Source Test (7/12/19)

Technology	DEC Cost Effectiveness Value (cost/ton removed)	Capital Cost ($)	Updated Cost Effectiveness Value (cost/ton removed)	Adjusted Capital Cost ($)
Selective Catalytic Reduction	$4,023/ton		Not Technically Feasible	
Selective Non-Catalytic Reduction	$2,227/ton		$2,587/ton	
Wet Scrubbers	$10,620/ton ($14,572/ton)	$57,019,437 ($87,152,852)	$49,585/ton	$82,323,012
Spray Dry Absorbers	$11,298/ton ($15,726/ton)	$51,019,437 ($81,280,628)	$53,909/ton	$77,293,649

Dry Sorbent Injection	$7,495/ton	$20,682,000	$18,007/ton	$20,604,000

Note: Values in parentheses are the output from the cost development methodology used by the DEC with inputs suggested within Section 7.7.8 "Control Strategies" of the draft Serious SIP.

Based on the adjusted values, it is not cost effective to install BACT for SO_2 at the Chena Power Plant.

<u>Response:</u>

The Department revised the baseline emission rates for NOx and SO_2 to 0.402 lb/MMBtu and 0.301 lb/MMBtu, respectively. These emission rates are the average of the two most recent approved source tests conducted on July 12, 2019 and the November 19, 2011. In calculating the average of the emission rates, the Department used 0.445 lb/MMBtu NOx and 0.471 lb/MMBtu SO_2 for the 2011 source test. These 2011 emission rates were provided to the Department both in the application for AQ0315ORL01 submitted in March of 2012 and again in the March 19, 2012 emissions fee estimate as indicated in Table 1 – Summary of Emissions Tests at the Chena Plant, November 19, 2011.

The Commenter contends that several more recent source tests have been conducted that are more representative of actual emissions at the source. However, the October 27, 2018 source test cited by the Commenter was ***not performed for any regulatory reason*** *as indicated in the December 26, 2018 source test report cover letter from Aurora to the Department and therefore not acceptable for calculating emissions (emphasis added).*

The Department acknowledges that the SO_2 emission rates at the Chena Power Plant may be lower than the 2011 tested values and the average used in the cost effectiveness calculation in the BACT Determination. The Department intends to work with Aurora to get the most representative data moving forward to ensure that the baseline emission rates are representative of actual emissions.

The Department notes that it does not plan to require implementation of SO_2 controls at the Chena Power Plant due to the financial indicators provided by Aurora and allowed under Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085. The Department finds that the financial indicators provided by Aurora are sufficient evidence to demonstrate that imposing add-on DSI controls on the existing coal-fired boilers would cause an adverse economic impact to Aurora. For more information see Appendix III.D.7.7 for Aurora's November 1, 2018 response to DEC's information request.

The Department intends to incorporate the 0.301 SO_2 emission rate into Aurora's air quality permits to ensure the limit is federally enforceable as a practical matter. EPA has indicated its position that controls and limitations used to limit a source's Potential to Emit must be federally enforceable. See 54 FR 27274 (June 28, 1989). Generally, to be considered federally enforceable, the permitting program must be approved by EPA into the SIP and include provisions for public participation. "In addition, permit terms and conditions must be practicably enforceable to be considered federally enforceable."

The Department notes the NOx controls proposed in this section are not planned to be *implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.*

Aurora Energy Comment (11):

Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request: Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, AE proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM and Aurora propose that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

Response:
The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into Aurora's air quality permit.

Requiring the change in sulfur content to be implemented on an as-delivered-basis will allow the coal already stockpiled at the Chena Power Plant to be utilized and ensure a continuous supply of coal is available.

c. SO_2 Precursor Analysis

Aurora Energy Comment (12):

Issue: There are inconsistencies in DEC's information with respect to SO_2. The major source contribution to sulfur-based PM2.5 from major source SO_2 ground level concentrations have increased from 2008; even though point source SO_2 emissions have decreased while SO_2 emissions from heating oil and total SO_2 emissions have increased.

Requests:

- Change referenced PM2.5 significance threshold from 1.3 μg/m^3 to 1.5 μg/m^3 based on the final EPA PM2.5 Precursor Demonstration Guidelines (2019).
- Revisit SO2 Analysis after applying representative emission rates for the Chena Power Plant for SO_2 and NOx (0.131 lbs-SO2/MMBtu and 0.359 lbs-NOx/MMBtu).
- Clarify discrepancy between the 2008 CALPUFF model output reflecting 22% contribution to ground-level SO2 from major sources and current CMAQ evaluation reflecting 39% SO2 contribution from major sources.
- Reconsider SO_2 Precursor Demonstration for Major Source impact using a sensitivity analysis to determine significance.

Background:

The DEC completed an SO2 Analysis using the 2019 projected baseline inventory and run through CMAQ model. All of the SO2 emissions were removed from the point source sector in a knock out model run. The meteorology used was from 2008, which is consistent for all of the model runs. The SO2 from major stationary sources were found to contribute significantly to the PM2.5 concentrations at the State Office Building (SOB) [1.79 µg/m^3] and at the monitoring site adjacent to the Borough building (NCORE) [1.70 µg/m^3] in Fairbanks. The impact of SO2 from major sources was also determined to be significant at all four monitoring sites (SOB, NCORE, Hurst Road, and NPE) when an alternative approach to estimating the design value contribution from major stationary sources was applied [respectively: 2.66 µg/m^3,2.53 µg/m^3, 1.55 µg/m^3, 1.35 µg/m^3]. The DEC referenced an insignificance threshold of 1.3 µg/m^3 to determine significance; however, final PM2.5 Precursor Demonstration Guidance has changed that threshold to 1.5 µg/m^3.[7]

Regardless of the change in significance value, three of the sites (SOB, NCOR, and Hurst Road) would still be considered significant when the alternative approach to estimating the design value contribution is considered. If the impact of major source SO_2 emissions on PM2.5 exceeds 1.5 µg/m^3, then a sensitivity- based analysis may be conducted to show that a reduction of SO_2 emissions in the range of 30 - 70% would only have an insignificant impact on lowering $PM_{2.5}$ concentration. Aurora demonstrated that there was justification to pursue a precursor demonstration using information provided in the moderate area SIP. The major source contribution to $PM_{2.5}$ from SO_2 was determined to be 1.98 µg/m^3 of water-bound ammonium sulfate. The conclusion of the exercise was that a 70% reduction in SO_2 would demonstrate insignificance of the SO_2 contribution from major sources on $PM_{2.5}$ concentration [i.e., 1.45 µg/m^3].[8] It is Aurora's opinion that a successful precursor demonstration may still be possible using a 50% reduction even considering DEC's alternative approach to estimating design value contributions from major source SO_2. However, the DEC has indicated due to sulfate model performance uncertainty and significance of the major source contribution from SO_2 emissions, there is not enough justification to pursue the demonstration.

Aurora has a few concerns with the SO_2 analysis. Probably the most significant is that the contribution of SO_2 at the SOB monitor from major sources increased to 39% from 22% as described in the Moderate Area SIP (2014). CALPUFF modeling showed that the point source SO_2 contribution to the SOB monitoring site was 22% for an episode in 2008. The emission inventory for 2008, 2013, and the projected 2019 show a decreasing trend in SO_2 emissions for point sources (See Table 5). The ratio between SO_2 emissions from oil heating and point sources (Oil Heating SO_2/Point Source SO_2) increases from 2008 to 2019 (projected) from 0.46 to 0.51 for the planning inventory in the NAA (Table 5). This would suggest that the amount of SO_2 emissions from oil increased in relation to the amount of SO_2 emissions from point sources. That fact is counterintuitive to the modeling outputs which indicates SO_2 contribution from point sources increased 18% from 2008 to 2019 at the SOB.

The total SO_2 emissions per day in 2019 is about two times what it was in 2008 and 2013 (See Table 5). The difference is attributed to an increase in Non-Road Mobile sources; in fact, a

[7] https://www.epa.gov/sites/production/files/2019-05/documents/transmittal_memo_and_pm25_precursor_demo_guidance_5_30_19.pdf

[8] Memo. Ramboll. "Summary of issues related to SO_2 precursor demonstration for Fairbanks". 2018.

change in jet fuel between 2013 and 2019 is referenced as the cause of the increase.[9] It would seem that the likelihood for an increased impact at the monitors from SO_2 should have come from this change as opposed to the point sources.

Table 5: Baseline Episode Average Daily SO_2 Emissions (tons/day) by Source Sector

Source Sector	Modeling Inventory Grid 3 Domain			Planning Inventory NA Area		
	2008	2013	2019 (projected)	2008	2013	2019 (projected)
Point Sources	8.380	7.40	7.32	8.167	7.22	7.13
Area, Space Heating, Oil	4.121	3.68	3.90	3.719	3.42	3.61
Total	12.875	12.65	25.58	12.155	11.92	22.36

Note: 2008 data from Moderate Area SIP (Table 5.6-7); 2013 & 2019 data from draft SIP, Tables 7.6-10 & 7.6-12, respectively.

The increase in point source contribution of SO2 at the monitoring sites is, therefore, perplexing. Aurora also believes that point source emission of SO_2 in the inventories may be inflated due to the emission factor used to determine Aurora's SO_2 emissions (and NOx emissions). Within the BACT section of the draft SIP, an emission factor for SO_2 was referenced as being 0.472 lbs-SO_2/MMBtu. A recent source test conducted on July 12, 2019 at the Chena Power Plant was arranged specifically to better characterize the emission rates for SO_2 and NOx from the plant. The test plan was approved by the state with additional scrutiny due to its intended use. The test demonstrated an emission factor of 0.131 lbs-SO_2/MMBtu. This value is a preliminary emission rate. The final report will be provided to the DEC so that, when approved, the new emission rate would be updated in the state's databases and worksheets for the final submittal of the Serious Area SIP to the EPA.

Aurora would also like the state to clarify the discrepancy between the 2008 CALPUFF modeling, which showed a major source SO_2 contribution of 22% at the SOB monitoring site, in relation to the recent evaluation referenced under the SO_2 Analysis (Section 7.8.12.5) where major source SO_2 contribution to the SOB was 39%. Aurora would like the DEC to reconsider an SO_2 precursor demonstration for major source contribution to $PM_{2.5}$ concentration. Aurora believes a successful demonstration could be done using the provisions of a sensitivity analysis as described in the 2019 $PM_{2.5}$ Precursor Demonstration Guidance.

<u>Response:</u>

The significance threshold has been updated to reflect 1.5 ug/m^3, which is in the precursor guidance. The discrepancies are due to the 2008 emissions inventory for Calpuff was an early version and used to estimate SO_2 into the non-attainment area. The CMAQ emission inventory was updated to reflect source specific day and hour emissions provided by the point sources. The SO_2 analysis was performed as a knock out run as outlined in the precursor guidance. DEC will not be reconsidering the SO_2 analysis for the Serious Area SIP. The EPA will not approve an SO_2 precursor regardless of the contribution because of outstanding science questions related to sulfate. Please see EPA comments on the SO_2 analysis:

[9] Section 7.6.3.2 "2019 Projected Baseline Emission Inventory", Draft Serious SIP

EPA Comment (4):

"SO_2 Precursor Analysis. We understand that there is interest in a precursor demonstration for SO_2, but that there are information limitations that restrict the ability to make such a demonstration. On page 43 of the modeling chapter, Vol. II:III.D.7.8, it is stated that no sensitivity-based precursor demonstration was pursued for SO_2 as a result of limitations on scientific information to support such a demonstration and therefore precursor emissions are considered significant. We agree with the State's conclusion that SO_2 precursor emissions are considered significant for the reasons provided by the State. Until the informational and technological limitations are addressed, SO_2 must be assessed for BACM and BACT for all source categories. See 40 CPR 51.1010(a). We summarize some of the informational and technological limitations here.

Model development for SO_2 and sulfate formation is an active area of research and we are hopeful to have improved modeling tools in the coming years. Beginning on page 47 of the modeling chapter and continuing on page 58, an SO_2 analysis is presented that attempts to quantify the point source contribution to total observed sulfate. EPA is concerned that, while the SO_2 analysis presented is not intended as a proposed precursor demonstration, the analysis makes several unsupported assumptions that we view as serious flaws in the methodology. First, it is assumed without supporting information that sulfur oxidation occurs uniformly throughout the airshed and on all sources of SO_2 at equal rates. Second, it is assumed that currently modeled sulfate impacting the monitors is an unbiased and accurate quantification of primary sulfate impacts at the monitors, essentially assuming the modeling is perfect in regard to primary sulfate impacts but does not provide a model performance evaluation that supports this assumption.

Given the technical limitations of current modeling tools to correctly model secondary sulfate in winter environments such as Fairbanks and the flaws in the presented SO_2 analysis, we agree that it does not make sense to pursue a sensitivity-based precursor demonstration at this time. (Improve)"

d. Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 μg/m^3 of PM2.5 is $9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 μg/m^3 of PM2.5 for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting

operational load to represent actual SO_2 emissions in the spreadsheets for each facility provided within the appendices of the “Control Strategies” section of the draft serious SIP.

- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO_2 BACT using actual emissions (instead of PTE).
- Correlate annualized cost of SO_2 BACT controls with results from the SO_2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost per $\mu g/m^3$ mitigated from applying SO_2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of $PM_{2.5}$ or any individual precursor (NOx, SO_2, NH_3, VOCs) are evaluated for appropriate control. NOx and SO_2 were addressed on an emission unit specific basis in DEC’s Best Available Control Technologies (BACT) determinations. The DEC’s evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit. Operations at the facility’s potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 $PM_{2.5}$ Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[10] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. Aurora believes that there is enough evidence to substantiate that SO_2 controls on the community of major sources is economically infeasible.

<u>Economic Infeasibility Justification</u>

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[11] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[12] It is within the DEC’s authority to determine that BACT for sulfur control is economically infeasible for the community of major sources in the NAA based on cost effectiveness.[13] If cost effectiveness is defined as cost per $\mu g/m^3$ removed, there is a clear justification to eliminate sulfur control measures from the community

[10] 40 CFR 51.1010 (3)
[11] Section 7.7.8 of the draft Serious SIP
[12] 40 CFR 51.1010 (3)
[13] 12 40 CFR 51.1010 (3)(ii)

of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 µg/m^3 of PM2.5 is $9,794,799 per year [See Table 7b].

Annualized Cost of BACT Implementation

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[14] Dry Sorbent Injection (DSI) is selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013) [15] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed[2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

Table 6b: BACT Annualized Costs Based on Actual Emissions

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULSD	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULSD	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULSD	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

[14] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/
[15] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC

Major Source SO_2 Control Cost Effectiveness: Cost per μg/m^3 $PM_{2.5}$ Removed

The DEC provided an SO2 analysis using the 2019 projected baseline inventory.[16] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 μg/m^3 and 1.70 μg/m^3 respectively.[17] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 μg/m^3 and 0.10 μg/m^3 respectively.

Assuming that an 80% removal of the point source emissions of SO2 would translate to an 80% reduction to the impact from major sources of sulfur-based PM2.5 at the monitors, the amount of PM2.5 reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 μg/m^3, 1.36 μg/m^3, 0.03 μg/m^3, and 0.08 μg/m^3 respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per μg/m^3 of $PM_{2.5}$ removed is at the best, $14,555,400 per μg/m^3 removed and at the worst $651,354,137 per μg/m^3 removed (Table 7a). If the alternative approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is $9,794,799 per μg/m^3 and at worst is $19,299,382 per μg/m^3 (Table 7b).

Ironically, the cost per μg/m^3 removed is less at the SOB and NCORE sites where the projected design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 μg/m^3 and 29.01 μg/m^3 respectively[18]; the attainment standard is 35 μg/m^3. The 2019 design values at the Hurst Road and NPE monitors were 104.81 μg/m^3 and 36.48 μg/m^3, both clearly above the attainment standard of 35 μg/m^3. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projected Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	$ 14,555,400
Fairbanks Borough Building	37.96	29.01	1.70	1.36	4.7%	$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projected Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	$ 9,794,799
Fairbanks Borough Building	37.96	29.01	2.53	2.02	7.0%	$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	$ 19,299,382

Notes:

[16] Section 7.8.12.5 of the draft Serious SIP
[17] Table 7.8-26. "Design value contribution from major stationary source SO2".Draft Serious SIP.
[18] Table 7.8-29. "2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year".

1 - Table 7.8-29 of Draft Serious SIP					
2 - Table 7.8-27 of Draft Serious SIP					

Fairbanks exceeds the fine particulate matter standard during winter months.[19] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of $10 million dollars per µg/m^3 seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, Aurora supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

Response:

The Department has not taken the approach suggested by the Commenter related to conducting an economic feasibility determination for the community of stationary sources. Rather, the Department conducted BACT Determinations for each individual stationary source located in the Serious nonattainment area.

Per federal requirement, DEC evaluated all point sources with emissions greater than 70 TPY of PM2.5 or for any individual PM2.5 precursor (NOx, SO_2, NH_3, VOCs). These units are subject to site-specific review for BACT. A BACT limit is a numerical emission limit that is needed for each emission unit for each pollutant subject to review. The limit must be met on a continual basis; specify a control technology or work practice; include an averaging period; and be enforceable as a practical matter. BACT analyses are detailed in the BACT Determinations and the Control Strategies chapter of the SIP.

The Department notes that Dry Sorbent Injection was cost effective for a BACT control in a serious non-attainment area, but Aurora provided financial indicators that demonstrated that it would have an adverse effect for business purposes. As indicated in the Control Strategies chapter, DEC finds that it is economically infeasible for Aurora Energy to implement retrofit SO_2 controls on its emission units at the Chena Power Plant.

e. $PM_{2.5}$ Emission Reduction Credits

Issue: Currently there are no provisions for the FNSB NAA within the regulations that establish emission reduction credits.

Request: Include provisions in the Serious SIP for establishing PM2.5 emission reduction

[19] Section 7.8.6 of the Draft Serious SIP

credits per 40 CFR 51 Appendix S.

Background:

Aurora Energy requests that the SIP include provisions for establishing PM2.5 emission reduction credits, as provided in 40 CFR 51 Appendix S. The SIP should recognize that the most fertile area for establishing further emission reduction credits involves reducing emissions from wood-fired residential heaters – stoves and fireplaces. The approach to accounting for dried wood emissions should consider enhanced wood-moisture reduction through a process such as kiln drying, to levels as low as 15 percent (dry wood basis) beyond the 20 percent levels in the proposed SIP and allow those lower emissions to be applied as emission reduction credits for potential future development within the Non-Attainment Area. The approach also lessens the level of involvement of agency oversight of the individual components of the SIP that are related to residential wood combustion. Residential wood combustion is an ingrained cultural component of life in Fairbanks, and the proposed enhanced drying option is likely to be well supported by members of the community. We urge consideration of this approach that will both clean the air and provide some potential for emissions increases, through offsets developed under this proposal, to further strengthen the economic viability of the Fairbanks North Star Borough community.

f. Conclusion

In summary, there are several elements to the SIP that Aurora is addressing as a part of the public comment. The DEC has an incredible task which is being addressed to the extent possible with the time and resources available. Below are summaries of the key points Aurora addressed within the comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. Auroras requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated on a six-month weighted average using UCM analyses for each shipment.
- SO_2 and NOx emission rates being used for Aurora within the SIP are not accurate representation of the facilities emission rates. Suggest using newly established rates derived through representative source testing with representative coal.
- Additional information is provided to support technologic infeasibility of SCR, a change in the capital cost for DSI, and emission rate changes for the determination of cost effectiveness within the context of the BACT analyses.
- Aurora supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 μg/m^3 of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.
- Aurora requests that the SIP include provisions for establishing $PM_{2.5}$ emission reduction credits, as provided in 40 CFR 51 Appendix S.
- One of the key parts to the future of the nonattainment area is the 5% reduction plan. The elements within this plan, which is anticipated for submittal at the end of 2020, have not been communicated to the community or industry. It is the opinion of Aurora that

communication with the community about the elements within the 5% reduction plan is warranted and necessary.

- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged.
- Retrofit control devices should be encouraged for use to meet emission standards as necessary.
- The departments' imposition of control technologies on small sources, such as coffee roasters, is not supported. Major sources are able to take operational limits to reduce emissions to less than 70 tons per year to avoid pollution control. Small commercial sources shouldn't be subject to pollution controls unless there is evidence that their emissions are significant.

Enclosure:

Stanley Consultants, Inc. (2019, April). "Best Available Control Technology Analysis – Independent Assessment of Technical Feasibility and Capital Cost". Aurora Energy, LLC.

2. Comments from Usibelli Coal Mine, Inc..

Note: Usibelli Coal Mine comments not related to BACT were summarized and addressed previously in the corresponding sections of the Response to Comment document.

a. Device Requirements

Issue: DEC is adopting emission rates for solid fuel heating devices and requirements that do not give all devices equal consideration. Installation of coal-fired heating devices are not allowed unless they are a listed device (18 AAC50.079). There are no standards available in the regulations for the determination of a qualifying coal-fired heating device. Certain devices are not given options for installation within the regulation. Non-pellet fueled wood-fired hydronic heaters, although may have EPA certification under Subpart QQQQ, are not allowed to be installed within the nonattainment area per 18 AAC 50.077 (b) & (c).

Request:

- Develop standards to qualify the installation of coal-fired heating units. Suggested standard should be consistent with 18 g/h emission rate for existing units or 0.10 lbs/MMBtu [heat input basis] whichever is greater.
- Allow the installation of non-pellet fueled wood-fired hydronic heaters provided they are EPA certified.

Background:

The DEC is adopting several different emission rates for solid fuel heating devices which does not give all devices an equal consideration. There are EPA standards for wood stoves and hydronic heaters; also alternative standards for cordwood fired hydronic heaters.[20] These standards should be adopted without alteration. Both wood stoves and pellet fired hydronic heaters emission rates in the SIP are consistent with the 40 CFR Part 60, Subpart QQQQ standard for wood heating devices. The standards are set by the EPA and apply to manufacturers of the wood heating devices. Any such device that is approved by the EPA should be allowed in the nonattainment area, this includes outdoor hydronic heaters. Existing residential and smaller commercial coal-fired devices are required to be removed by December of 2024 and new coal-fired devices are prohibited from installation within the nonattainment area.[21] Coal-fired devices currently installed can be subject to an in-use source test to demonstrate the device meets the standard of 18 g/h of total particulate matter. This standard should also be the criteria for new residential and smaller commercial coal-fired devices. The 18 g/h standard is consistent with 0.10 lbs/MMBtu (heat input) emission rate for a unit that is rated at 400,000 Btu/hr. The Titan II auger-fed coal boilers are rated at 440,000 Btu/hr (heat output) and have undergone testing through OMNI Test Labs; the same lab that derived emission rates for the DEC which are being used in the nonattainment area SIPs. The OMNI test conducted in 2011 demonstrated that auger-fed coal fired hydronic heaters are extremely efficient. Ranking among the lowest emission rates for units tested. Emission rates of auger-fed coal-fired hydronic heaters (0.027g/MJ; **0.06 lbs/MMBtu[heat output basis]**) were consistent with EPA Certified Woodstoves (0.041 g/MJ; **0.10 lbs/MMBtu [heat output basis]**).[22] The DEC is aware that more efficient heating is better for the nonattainment area situation regardless of heating device. Acceptable standards for the installation of coal-fired units should be included within the proposed regulations. There should not only be a standard for the existing units referenced in the regulations but also an achievable emission rate and standards for new coal-fired units. While there are provisions for the department's approval contingency, it does not provide a target emission rate for respective devices and fuels that are not EPA certified.

Best Available Control Technologies (BACT)

The proposed SIP considers BACT for the major sources; however, authorization of the BACT determination is not finalized through the EPA. With an impending date to install BACT four years from the date of reclassification (i.e., June 9, 2021), there doesn't seem to be time for any technological changes to the community of major sources. Although the state is trying to accommodate the deadline for BACT implementation through creative agreements (e.g., Fort Wainwright), the DEC alternatively could provide justification that the implementation of BACT is both technologically and economically infeasible at this time. This option is available to the state through 40 CFR 51.1010 (3). The economically infeasible consideration is relevant

[20] Federal Register, Vol. 80, No.50, Monday, March 16, 2015. Pg. 13672.
[21] Section 7.7.5.1.2 "Device Requirements – wood-fired and coal- fired standards", Draft Serious SIP.
[22] OMNI-Test Laboratories, Inc. 2011. Measurement of Space- Heating Emissions. Prepared for FNSB. Retrieved from https://cleanairfairbanks.files.wordpress.com/2012/02/omni-space- heating- study- fairbanks- draft- report-rev- 4.pdf

due to the cost of implementation of sulfur controls on the major sources for its potential gain in $PM_{2.5}$ reduction (approx. \$10 million for 1 μg/m^3 removed). A technologic infeasibility case could be considered on the basis that impending deadlines for BACT implementation is constrictive. The actual time it would take to design, build and implement sulfur controls for any facility cannot be accommodated in the time allotted. If either approach is accepted by the EPA, no further consideration would be necessary for BACT. UCM is also providing a justification for the use of a 0.25% coal-sulfur content as opposed to the 0.2% coal-sulfur content proposed by the DEC in the Serious SIP.

<u>Response</u>

As indicated in the Control Strategies chapter, the Department does not plan to require implementation of SO_2 controls at the Chena Power Plant due to the financial indicators provided by Aurora and allowed under Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085. The Department finds that the financial indicators provided by Aurora are sufficient evidence to demonstrate that imposing add-on DSI controls on the existing coal-fired boilers would cause an adverse economic impact to Aurora. For more information see Appendix III.D.7.7 for Aurora's November 1, 2018 response to DEC's information request.

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore the Department acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into Aurora's air quality permit.

Requiring the change in sulfur content to be implemented on an as-delivered-basis will allow the coal already stockpiled at the Chena Power Plant to be utilized and ensure a continuous supply of coal is available.

b. Technological Infeasibility

Issue: BACT determination for Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) is not justifiable considering the DEC's options under the 2016 $PM_{2.5}$ Implementation Rule.

Request: The option to determine BACT on FWA CHPP for SO_2 emissions is technologically infeasible due to time constraints is within DEC's authority. As such, a demonstration asserting that condition should be made.

Background:

BACT determination for the Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) is arguably not justifiable per the requirements proposed in the draft Serious SIP. The Army installation was given two choices; either to retire the FWA CHPP or install and operate Dry Sorbent Injection (DSI) pollution control on the coal-fired boilers. As indicated, FWA is conducting a National Environmental Policy Act (NEPA) analysis to evaluate replacing the industrial coal-fired boilers which may take 2.5-3 years for a Record of Decision (ROD) [e.g., 2021 or 2022]. Since a determination captured in a ROD would come after the required installation date for BACT (i.e., June 9, 2021), the DEC is requesting an enforceable agreement to be made prior to the final submittal of the SIP (i.e., late 2019/early 2020). The agreement would be part of a Compliance Order by Consent (COBC) setting a date for either decommissioning the plant or installation of pollution controls. Realistically, whether the ROD determined the plant was to be decommissioned, alternative heating was proposed, or a do-nothing option was considered, the timeline for implementation of the agreement could be realized after DEC's expeditious attainment date of 2029.

Based on 40 CFR 51.1010 (3), the state may make a demonstration that any measure identified is "not technologically or economically feasible to implement in whole or in part by the end of the tenth calendar year following the effective date of the designation of the area, and may eliminate such whole or partial measure from further consideration under this paragraph." Since it is established that BACT implementation is not possible by June 9, 2021, it would seem reasonable to consider the option as technologically infeasible.

c. Sulfur Content of Coal

Issue: Proposed BACT for coal-sulfur content of 0.2% will cut off access to tens of millions of tons of coal for UCM as well as pose a potential threat of fuel supply interruption for the coal fired power plants.

Request:

- Adopt a new standard of 0.25% based on semi-annual weighted averages of coal-sulfur content in shipments of coal within semi-annual periods corresponding to Facility Operating Report reporting periods.
- Include provisions or circumstances within the SIP when the imposed coal-sulfur limit can be relaxed.

Background:

The ADEC has proposed that Best Available Control Technology (BACT) for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There isn't a coal washing or segregating facility associated with UCM which could ensure a consistent coal-sulfur concentration. Current practice for providing low-sulfur coal to customers is identifying sulfur content of the resource through drilling and sampling efforts. However, no matter how much sampling is done, the ability to characterize the sulfur content of the coal actually mined is limited.

Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2%; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, UCM proposes that the coal-sulfur limit be lowered to 0.25% on an as received basis (wet) as opposed to 0.2% as proposed by ADEC. The increase in coal-sulfur content will help with coal accessibility and availability over the next decade and still provides ADEC with a 37.5% reduction in the potential to emit based from the current limit of 0.4%.

The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides semi-annual reports to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. UCM proposes that the standard operating permit condition remain the same and that facilities continue to provide the state with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

UCM would like the DEC to include circumstances when any imposed reduced coal-sulfur limit can be relaxed. Situations when relaxing the coal-sulfur limit will not impede attainment of the $PM_{2.5}$ standard should be considered when drafting the proposed regulations. As previously indicated, coal resources are effectively being cut off by the imposition of a reduced limit. An example when relaxing the coal-sulfur limit wouldn't impede attainment of the standard is if sulfur controls were acquired on a coal-fired facility. The state and the facility would, inevitably, work out an emission rate for the facility. The subsequent fuel-sulfur loading requirement would be established in order for the facility to meet their emission limit. If the fuel-sulfur loading requirement could be in excess of the coal-sulfur limit while still allowing the facility to meet the emission limit; that should qualify as a criteria to relax the limit. Another condition may be when the area comes into attainment with the $PM_{2.5}$ standard. Perhaps one of the aspects of a maintenance state implementation plan could be to remove or relax the imposed coal-sulfur limit on the basis that the impact from coal-sulfur is negligible to the area problem.

Response

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore the Department acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into the air quality permits of the stationary sources in the Fairbanks nonattainment area.

With respect to the potential for changing the coal sulfur limit in the future, the Department has not added discussion in this Serious SIP of any future changes to control measures because it would be premature to do so. The Department acknowledges that when the area comes into attainment and a maintenance plan is developed, there may be opportunities to revisit control measures, including coal sulfur limits, consistent with any federal planning requirements in place at that time.

d. Major Source Economic Infeasibility Justification

Issue: The DEC has the option to demonstrate the economic infeasibility of SO_2 BACT for major sources within the nonattainment area under 40 CFR 51.1010 (3) based on cost effectiveness. The most cost effective value for operating BACT controls on the community of major sources to remove 1 µg/m^3 of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

Request:

- Define cost effectiveness as cost per 1 µg/m^3 of $PM_{2.5}$ for this exercise.
- Derive a cost per ton removed for each major source in the nonattainment area by adjusting operational load to represent actual SO_2 emissions in the spreadsheets for each facility provided within the appendices of the "Control Strategies" section of the draft serious SIP.
- Evaluate the cumulative annualized cost incurred by the community of major sources within the nonattainment area based on potential tons removed from implementing SO_2 BACT using actual emissions (instead of PTE).
- Correlate annualized cost of SO_2 BACT controls with results from the SO_2 Analysis section of the draft SIP (Section 7.8.12.5) to derive a cost/µg/m^3 mitigated from applying SO_2 control technologies.

Background:

Major stationary sources are a subgroup of emission sources that are given special consideration under nonattainment area provisions. Point sources with emissions greater than 70 tons per year of $PM_{2.5}$ or any individual precursor (NOx, SO_2, NH_3, VOCs) are evaluated for appropriate control. NOx and SO_2 were addressed on an emission unit specific basis in DEC's Best Available Control Technologies (BACT) determinations. The DEC's evaluation considered technical feasibility and estimates of emissions reductions to meet a defined emission limit. Operations at the facility's potentials to emit is used for the purpose of identifying a cost effectiveness for each technology in cost per ton removed.

The BACT analyses evaluate pollution control independent of the nonattainment area problem; it is simply triggered as a condition of an area defined as being in serious nonattainment of a pollutant standard. As described in the 2016 $PM_{2.5}$ Implementation Rule, the state can provide either a technologic or an economic infeasibility demonstration for control measures.[23] The argument must illustrate it is not technologically or economically feasible to implement the control measure by the end of the tenth calendar year (i.e., December 31, 2019 for the FNSB NAA) following the effective date of the designation of the area. UCM believes that there is enough evidence to substantiate that SO_2 controls on the community of major sources is economically infeasible.

<u>Economic Infeasibility Justification</u>

The DEC has determined BACT is comprised of sulfur controls for major stationary sources. The DEC has also determined that sulfur controls are economically infeasible for one major source, silent on infeasibility for another, and partially economically infeasible for a couple of major sources within the NAA.[24] Per regulation, DEC has the authority to demonstrate that any measure identified is economically infeasible.[25] It is within the DEC's authority to determine that BACT for sulfur control is economically infeasible for the community of major sources in the NAA based on cost effectiveness.[26] If cost effectiveness is defined as cost per $\mu g/m^3$ removed, there is a clear justification to eliminate sulfur control measures from the community of major sources. The most cost effective value for operating BACT controls on the community of major sources to remove 1 $\mu g/m^3$ of $PM_{2.5}$ is $9,794,799 per year [See Table 7b].

<u>Annualized Cost of BACT Implementation</u>

The DEC derived cost effectiveness value in cost per ton removed is established through the implementation of the BACT analysis. The DEC preferred BACT controls and cost effectiveness value are referenced in Section 7.7.8 of the SIP.[27] Dry Sorbent Injection (DSI) is

[23] 40 CFR 51.1010 (3)
[24] Section 7.7.8 of the draft Serious SIP
[25] 40 CFR 51.1010 (3)
[26] 40 CFR 51.1010 (3)(ii)
[27] Appendix III.D.7.07 Control Strategies: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/

selected for the coal fired boilers with an 80% reduction in SO_2 and ULSD is suggested for GVEA's North Pole Plant and Zehnder Facility with a 99.7% removal rate for SO_2. Based on the Potential to Emit (PTE) of each facility, the state derives a cost effectiveness value for the sources.

Annualized cost to implement BACT for the community of major sources are based on operating scenarios for both PTE and actual emissions (2013)[28] from the facilities. The results are illustrated in Table 6a and 6b. The cost effectiveness value (cost/ton removed) is multiplied by the amount of pollution removed (tons) to derive an annual cost for BACT for each facility. The total annualized cost is the sum of the cumulative annual operating cost for the controls on all the major sources in the NAA. The annualized costs do not include the cost of fuel switching for smaller diesel engines, backup generators and boilers that are found on the campuses of certain facilities (e.g., UAF, FWA). The total annualized BACT implementation cost to operate at the PTEs is $49,296,062; annualized cost considering actual emissions is $20,843,332 (See Tables below).

Table 6a: BACT Annualized Costs Based on Potential To Emit

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions PTE[3]	SO_2 Reduction[3]	Cost/ton removed[2,3]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	1,004.0	803.0	$ 7,495	$ 6,018,485
FWA	DSI	80	1,168.5	934.8	$ 10,329	$ 9,655,331
NPP-EU1	ULSD	99.7	1,486.4	1,482.0	$ 9,139	$ 13,543,998
NPP-EU2	ULSD	99.7	1,356.1	1,352.0	$ 9,233	$ 12,483,016
UAF	DSI	80	242.5	194.0	$ 11,578	$ 2,246,132
Zender	ULSD	99.7	598.6	597.0	$ 8,960	$ 5,349,120
Notes: See Below.					Total Annualized Cost	$ 49,296,082

Table 6b: BACT Annualized Costs Based on Actual Emissions

Facility	BACT (SO_2 Control)	SO_2 Reduction	SO_2 Emissions (Actual)[1,3]	SO_2 Reduction	Cost/ton removed[4]	Annualized Cost
Units		(%)	(tpy)	(tpy)	($)	($)
Chena Power Plant	DSI	80	711.8	569.4	$ 8,960	$ 5,101,824
FWA	DSI	80	766.5	613.2	$ 11,235	$ 6,889,302
NPP-EU1	ULSD	99.7	142.3	141.9	$ 12,169	$ 1,726,454
NPP-EU2	ULSD	99.7	422.3	421.0	$ 9,453	$ 3,980,026
UAF	DSI	80	219.0	175.2	$ 11,578	$ 2,028,466
Zender	ULSD	99.7	73.0	72.8	$ 15,351	$ 1,117,261
Notes:					Total Annualized Cost	$ 20,843,332

1 - Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emissions (tons/day)"
2 - Sectoin 7.7.8 of SIP
3 - BACT Spreadsheets (May 2019) in SIP for Listed Facilities; adjusted AE emission factor of 0.472 lbs-SO2/MMBtu referenced in BACT Section of SIP.
4 - Cost/ton removed after adjusting operational load in BACT Spreadsheets (May 2019) to reflect actual emissions; AE emission factor of 0.472 lbs-SO_2/MMBtu

Major source SO_2 Control Cost Effectiveness: Cost per $\mu g/m^3$ $PM_{2.5}$ Removed

The DEC provided an SO_2 analysis using the 2019 projected baseline inventory.[29] The DEC determined that major stationary sources were found to contribute significantly to $PM_{2.5}$ concentrations at the State Office Building (SOB) and the monitor adjacent to the Borough

[28] Table 7.6-9 "2013 SO2 Episodic vs. Annual Average Point Source Emission (tons/day)"[Draft Serious SIP]ADEC
[29] Section 7.8.12.5 of the draft Serious SIP

building (NCORE) in downtown Fairbanks. The impact at the monitors were 1.79 µg/m^3 and 1.70 µg/m^3 respectively.[30] The impact at the Hurst Road and North Pole Elementary (NPE) monitors were 0.04 µg/m^3 and 0.10 µg/m^3 respectively.

Assuming that an 80% removal of the point source emissions of SO_2 would translate to an 80% reduction to the impact from major sources of sulfur-based $PM_{2.5}$ at the monitors, the amount of $PM_{2.5}$ reduced at the SOB, NCORE, Hurst Road, and NPE monitors would be 1.43 µg/m^3, 1.36 µg/m^3, 0.03 µg/m^3, and 0.08 µg/m^3 respectively. Based on the total annualized cost for BACT controls using actual emissions ($20,843,332) the cost effectiveness value in cost per µg/m^3 of $PM_{2.5}$ removed is at the best, $14,555,400 per µg/m^3 removed and at the worst $651,354,137 per µg/m^3 removed (Table 7a). If the alternative approach to the SO_2 design value contribution from major sources is considered then the cost effectiveness at best is $9,794,799 per µg/m^3 and at worst is $19,299,382 per µg/m^3 (Table 7b).

Ironically, the cost per µg/m^3 removed is less at the SOB and NCORE sites where the projected design value is in compliance with the standard. The projected design value provided by the DEC for 2019 meet attainment at the SOB and NCORE sites which are of 29.72 µg/m^3 and 29.01 µg/m^3 respectively[31]; the attainment standard is 35 µg/m^3. The 2019 design values at the Hurst Road and NPE monitors were µg/m^3 and 36.48 µg/m^3, both clearly above the attainment standard of 35 µg/m^3. The impact from the major sources is less significant at the sites where the 2019 projected design value violates the standard.

Table 7a: Cost Effectiveness Based on Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction / Design Value 2019	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	1.79	1.43	4.8%	$ 14,555,400
Fairbanks Borough Building (N	37.96	29.01	1.70	1.36	4.7%	$ 15,325,980
Hurst Road	131.63	104.81	0.04	0.03	0.0%	$ 651,354,137
North Pole Elementary (NPE)	45.3	36.48	0.10	0.08	0.2%	$ 260,541,655

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-26 of Draft Serious SIP

Table 7b: Cost Effectiveness Based on Alternative Approach to Design Value Contribution SO_2 from Major Stationary Sources

Site	Design Value Base Year 2013[1]	Projeced Design Value Year 2019[1]	Major Source Sulfur-Based Particulate Contribution[2]	BACT Reduction (80% of Direct Emissions)	BACT Reduction/Design Value 2019 x 100	Annualized BACT Cost per ug/m^3 removed
Units	(ug/m^3)	(ug/m^3)	(ug/m^3)	(ug/m^3)	(%)	($)
State Office Building (SOB)	38.93	29.72	2.66	2.13	7.2%	$ 9,794,799
Fairbanks Borough Building (N	37.96	29.01	2.53	2.02	7.0%	$ 10,298,089
Hurst Road	131.63	104.81	1.55	1.24	1.2%	$ 16,809,139
North Pole Elementary (NPE)	45.3	36.48	1.35	1.08	3.0%	$ 19,299,382

Notes:
1 - Table 7.8-29 of Draft Serious SIP
2 - Table 7.8-27 of Draft Serious SIP

[30] Table 7.8-26. “Design value contribution from major stationary source SO_2”.Draft Serious SIP.
[31] Table 7.8-29. ”2019 FDV for Projected Baseline and Control Scenario Calculated against a 2013 Base year”

Fairbanks exceeds the fine particulate matter standard during winter months.[32] Control technology application on major stationary sources is permanent and transcends seasons. BACT for sulfur control on major sources is an annual solution to a wintertime problem. The application of SO_2 BACT is arguably an impractical effort. Where the pollutant concentration is either achieving or almost achieving the standard, the projected impact removed by application of BACT on the major sources is about 7% of the concentration. Since the standard is attained, removing 7% more of sulfur-based $PM_{2.5}$ for costs upward of $10 million dollars per μg/m^3 seems impractical. There is a mechanism allotted within the 2016 $PM_{2.5}$ Implementation Rule for the DEC to provide a detailed written justification for eliminating, from further consideration, potential control measures for SO_2 on the community of major stationary sources based on cost ineffectiveness.

As such, UCM supports an economic infeasibility determination for the application of BACT on all major stationary sources within the nonattainment area.

Conclusion

In summary, UCM is thankful to have the opportunity to comment on the Serious Area SIP and the proposed regulations. UCM's main concerns expressed within these comments are the application of a common standard for solid fuel burning devices, the application of a workable coal-sulfur limit as BACT for the coal-fired facilities, and an economic infeasibility justification for sulfur controls for the community of major sources in the NAA. Included below are summaries highlighting key points of UCM's comments:

- BACT requirement for coal facilities to meet coal-sulfur content of 0.2% is being contested. UCMs requests a modified BACT requirement to 0.25% coal-sulfur (as received) evaluated on a six-month weighted average using UCM analyses for each shipment.

- UCM is encouraging the DEC to include provisions or circumstances within the SIP when the imposed coal-sulfur limit can be relaxed without impact to the nonattainment area. As indicated, coal resources are effectively being cut off by the imposition of a reduced limit.

- A demonstration asserting that it is technologically infeasible to install BACT for SO_2 on the FWA CHPP due to time constraints is within the DEC's authority under the provisions of the 2016 $PM_{2.5}$ Implementation Rule and should be considered.

- UCM supports an economic infeasibility determination for the community of major sources based on the cost ineffectiveness of sulfur control technology in removing 1 μg/m^3 of sulfur-based $PM_{2.5}$ from major source SO_2 contribution.

- Solid fuel burning devices are not treated equally within the Serious Area SIP. A proposition for a common emission standard for those units that do not have EPA certification or standard to meet is encouraged. Those units with EPA standards should be allowed to operate within the NAA. Also, inclusion of emission standards and criteria for coal-fired home heating devices within the regulation is encouraged.

[32] Section 7.8.6 of the Draft Serious SIP

Response

As indicated in the Control Strategies chapter, the Department does not plan to require implementation of SO_2 controls at the Chena Power Plant due to the financial indicators provided by Aurora and allowed under Federal Register, Vol. 81, No.164, Wednesday August 24, 2016. pg. 58085. The Department finds that the financial indicators provided by Aurora are sufficient evidence to demonstrate that imposing add-on DSI controls on the existing coal-fired boilers would cause an adverse economic impact to Aurora. For more information see Appendix III.D.7.7 for Aurora's November 1, 2018 response to DEC's information request.

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into the air quality permits for the stationary sources in the nonattainment area.

The Department notes that this change in sulfur content of the coal will not affect deliveries outside of the Fairbanks nonattainment area, allowing UCM to bring their higher sulfur content coal to market.

Fort Wainwright Response to Comments

Table of Contents

1. Comments from Doyon Utilities, LLC.

a. General Comments

Doyon Utilities Comment (1):

Section 7.7.8.3 of the proposed SIP document states incorrectly that the Fort Wainwright (FWA) Central Heat and Power Plant (CHPP) emissions units "are operated by a private utility company, Doyon Utilities, LLC (DU) and owned by the US Army Garrison Fort Wainwright."

The Central Heat and Power Plant (CHPP) was owned and operated by the Department of Defense until formally transferred to Doyon Utilities on August 15, 2008. Prior to transfer, Department of Defense solicited proposals for privatization of the CHPP and other electric and steam utility assets. DU was the successful bidder and signed a 50-year contract on September 28, 2007 to become the new owner and operator. For more than ten years, Doyon Utilities has owned and operated the plant under the economic jurisdiction of the Regulatory Commission of Alaska Certificate of Public Convenience and Necessity #725. Under the regulated model, DU recovers operating and capital costs through rates established by the RCA. In addition to economic regulation, DU is subject to environmental regulation as well. DU has held a series of air permits from ADEC for the emissions units in the CHPP. The Army does not maintain a physical presence at any of DU's facilities, nor is the Army responsible for day to day operational discussions. As the customer who pays for utility services via tariff rates, the Army is interested in compliance issues of DU's facilities.

Response:

The Department made a technical correction to Section 7.7.8.3 of the SIP Control Strategies chapter to clarify that the EUs at the CHPP are owned and operated by Doyon Utilities, LLC (DU).

Doyon Utilities Comment (2):

Section 7.7.8.3 of the proposed SIP document and Tables A and B of the proposed Best Available Control Technology (BACT) Determination do not reflect the asset transfer of several generator engines from DU to the Army in late December 2018. The documents identify those engines as DU emissions units instead of Army garrison emissions units. DU submitted a notification of these changes to the Alaska Department of Environmental Conservation (ADEC) on December 31, 2018. See Attachment 2 for a copy of this notification.

Response:

The Department revised the emissions unit inventory to reflect the transfer of the EUs from DU to the Army.

Doyon Utilities Comment (3):

In some instances, the proposed SIP document and the underlying proposed BACT Determination are inconsistent with respect to applicable emissions limits and other requirements. Because both documents will become part of the SIP, please ensure that these two documents are internally consistent and clearly state which requirements are applicable to each emissions unit. DU has attempted to address specific inconsistencies in the subsequent comments.

Response:

The Department revised the SIP Control Strategies chapter and the BACT Determination to ensure consistency with respect to applicable emissions limits. The Department included Table 4-9 from the BACT Determination into the SIP Control Strategies chapter Section 7.7.8.3.2 to clearly identify the numerical BACT limits for the diesel-fired engines. The Department also included a bullet preceding the table to clarify that compliance with the limits will be demonstrated by maintaining records of maintenance procedures conducted in accordance with 40 C.F.R. Subparts 60 and 63, and the EU operating manuals. The Department also included a table in the beginning of the SIP Control Strategies chapter Section 7.7.8.3 titled "DEC BACT and SIP Findings Summary Table" which includes the Department's final decisions and timelines.

b. BACT for Nitrogen Oxides (NOx)

In Section 7.7.8.3.1 of the proposed SIP document, ADEC states that "the NOx controls proposed in this section are not planned to be implemented." In the event that the U.S. Environmental Protection Agency (EPA) does not approve the precursor demonstration as justification not to require NOx controls, DU provides the following comments on the proposed NOx BACT determination and associated SIP requirements.

Doyon Utilities Comment (4):

If NOx BACT is required, the proposed BACT for the CHPP coal-fired boilers, Emissions Units 1 through 6, is selective catalytic reduction (SCR). The proposed emission limit is 0.060 pounds per million British thermal units (lb/MMBtu) averaged over three hours. The proposed SIP document and supporting proposed BACT Determination do not provide engineering design data supporting this emission limit for these boilers. How did ADEC determine that this emission limit was appropriate? The calculation of the emission limit is based on a 90 percent reduction in NOx emissions compared to the baseline. A 90 percent reduction is the typical maximum reduction that can be expected from the use of SCR. However, no specific engineering information is presented to support the conclusion that a 90 percent NOx emission reduction is achievable for the DU CHPP boilers, particularly in light of the economic analysis discrepancies, addressed below.

Response:

The Department did not revise the proposed NOx BACT limit for EUs 1 through 6 because it finds that 0.060 lb/MMBtu is an achievable limit for coal-fired boilers equipped with an SCR control system. As indicated in Chapter 2 of the June 2019 edition of EPA's Cost Control Manual for SCR: [33]

> *"Theoretically, SCR systems can be designed for NOx removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu)."*

The Department is unable to provide detailed engineering design data supporting the proposed NOx emission limit in the absence of site-specific vendor quotes for each NOx control technology. As indicated in the Department's September 10, 2018 request for additional information, "the cost analyses must be based on emission unit-specific quotes for capital equipment purchase and installation costs at Fort Wainwright." Without this information, a reasonable estimation of an achievable BACT limit must be used.

As indicated in Footnote 7 of the BACT Determination for Fort Wainwright, the 0.060 lb/MMBtu emission limit was calculated using the emission factor from AP-42 Table 1.1-3 for spreader stoker, sub-bituminous coal (8.8 lb NOx/ton) and converted to lb/MMBtu using the typical gross as received heat value for Usibelli Coal[34] *of 7,560 Btu/lb, assuming a 90 percent control efficiency for SCR.*

$$\left(\frac{8.8\ lb_{NOx}}{ton_{coal}}\right)\times\left(\frac{ton_{coal}}{2000\ lb_{coal}}\right)\times\left(\frac{lb_{coal}}{7560\ Btu}\right)\times\left(\frac{10^6 Btu}{MMBtu}\right)\times\left(\frac{100\% - 90\%}{100\%}\right) = \left(\frac{0.058\ lb_{NOx}}{MMBtu}\right)$$

However, as noted in the newly inserted BACT and SIP findings summary table in the SIP Control Strategies chapter Section 7.7.8.3, the Department is not requiring NOx controls for Fort Wainwright assuming the precursor demonstration is approved by the EPA.

Doyon Utilities Comment (5):

The economic analysis spreadsheet[35] is a cost model offered to support the SCR BACT determination. The cost model was developed by Sargent & Lundy (S&L) but does not appear to be an appropriate model for costs pertaining to the DU CHPP boilers. Additionally, the inputs to the cost model may not be appropriate or adequate to properly determine costs.

DU reviewed the cost effectiveness model and supporting documentation. The validity of the model cannot be confirmed based on the information that ADEC made available in the public

[33] https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf
[34] http://www.usibelli.com/coal/data-sheet
[35] 2019-05-10-adec-calculated-scr-economic-analysis-for-wainwright.xlsm

record. From what is available in the public record, DU can note three assumptions in the model that do not look appropriate as applied to DU.

- ADEC assumed that the model is valid for a plant the size of DU's CHPP.

The S&L SCR Cost Development Methodology[36] white paper dated January 2017 addresses several caveats which are not identified or addressed in the draft BACT Determination. The white paper states that "the costs for retrofitting a plant smaller than 100 megawatts (MW) increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units." The draft BACT Determination does not appear to adjust for the expected increased costs for retrofitting smaller plants such as the DU CHPP. DU's CHPP boilers each have a maximum heat input rate of 250 MMBtu/hr which is an equivalent maximum input of approximately 75 MW. The DU CHPP boilers have an output significantly less than 100 MW. As a result, as noted in the S&L white paper, the cost model should have been adjusted for size; because the adjustment was not made, the cost model would underestimate emissions control costs for EUs 1 through 6.

The S&L white paper states that older units typically have limited space in which to add an SCR reactor and associated ductwork, and that the existing fans may not be sufficient to overcome the added pressure drop. The proposed BACT determination does not discuss these concerns. Whether the cost model as applied by ADEC accounts for these issues is unclear. DU readily confirms there would be significant design confirms for physical space and fan capacity if the boilers were to be retrofitted with SCR.

- The proposed BACT Determination assumes that multiple boilers can accurately be modeled using a totaled heat input in a single spreadsheet.

The S&L white paper states that "a combined SCR for small units is not a feasible option." Each boiler requires a single, dedicated SCR reactor due to the needed heat recovery.

Review of the spreadsheet provided by ADEC, reflects the proposed BACT considers EUs 1 thorough 6 as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities necessary to independently operate six boilers. The actual installation will require six separate trains of reagent processing and transport equipment. Each train contains a various feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit.

- ADEC assumed that the model is valid for a heat and power plant.

No information is available addressing the type of plant on which the S&L spreadsheet is based. It appears S&L assumed that the plant is a single power generation unit. However, a combined heat and power (CHP) plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. DU is unable to confirm that the direct annual costs can be accurately modeled for an installation such as the DU's EUs 1

[36] https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf

through 6 by using the S&L spreadsheet.

Response:

The Department did not use the cost model developed by Sargent and Lundy for estimating SCR costs pertaining to the CHPP boilers. Rather, it used EPA's 2016 SCR Cost Manual Spreadsheet.[37] *As indicated in the Read Me tab of this spreadsheet, it can be used to estimate capital and annualized costs for applying SCR to coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour. As indicated in DU's comment, "CHPP boilers each have a maximum heat input rate of* ***250 MMBtu/hr*** *which is an equivalent maximum input of approximately 75 MW" (emphasis added). Therefore, absent a detailed engineering study and cost quotations from system suppliers, the Department finds this spreadsheet to be the most appropriate approach for estimating the cost effectiveness for implementing SCR control on the boilers. Regarding the type of plant for which the spreadsheet is based (traditional vs. combined heat and power), "the size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs."* [37]

The Department acknowledges that the methodology of calculating SCR cost effectiveness using one combined heat input for the six coal-fired boilers (with six individual exhaust stacks) may result in an underestimate of the actual costs due to an economy of scale. Therefore, the Department recalculated the cost effectiveness for installing SCR on each 230 MMBtu/hr boiler using a baseline emission rate of 0.58 lb NOx/MMBtu, a difficult retrofit factor of 1.5 (the EPA spreadsheet has a retrofit factor difficulty ranging from 0.8 to 1.5), a NOx removal efficiency of 90%, an interest rate of 5.0% (current bank prime interest rate), and a 20 year equipment life. The resulting cost effectiveness value for installation of SCR NOx controls is $7,214 per ton of NOx removed. For additional information see the Fort Wainwright SCR Economic Analysis Spreadsheet in Appendix III.D.7.07 to the Control Strategies Chapter on the Fairbanks Serious SIP website at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/.

Doyon Utilities Comment (6):

Section 3.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(c), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6 of that permit). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 Code of Federal Regulations (CFR) 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of Permit AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT

[37] https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm

requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

<u>Response:</u>

The Department revised the limited operational requirement for EU 8 in Section 3.3 of the BACT Determination and Section 7.7.8.3.1 of the SIP Control Strategies chapter to clarify that EU 8 has the option to be converted to a non-emergency engine with a 500 hour per year limit, per Operating Permit AQ1121TVP02 Rev. 2.

<u>Doyon Utilities Comment (7):</u>

Please include a statement in Section 3.3 of the proposed BACT Determination and Section 7.7.8.3.1 of the proposed SIP document to clarify that EU 8 shall demonstrate compliance with the numerical BACT emission limit by complying with the applicable NOx emission standard in 40 CFR 60 Subpart IIII.

<u>Response:</u>

The Department revised Section 3.3 of the proposed BACT Determination and Section 7.7.8.3.1 of the proposed SIP Control Strategies chapter to clarify that "for the engines subject to 40 C.F.R. 60 Subpart IIII, demonstrate compliance with the numerical BACT emission limits by complying with the applicable NOx emission standards in 40 C.F.R. 60 Subpart IIII."

<u>Doyon Utilities Comment (8):</u>

Section 3.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(a), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of Permit AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

<u>Response:</u>

The Department revised Section 3.4 of the BACT Determination and Section 7.7.8.3.1 of the SIP Control Strategies chapter to clarify that the 100 hours per year limit is for non-emergency operations.

Doyon Utilities Comment (9):

Section 7.7.8.3.1 of the proposed SIP document states that BACT for NOx emissions from the small diesel-fired engines includes the requirement that "for engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, comply with the applicable NOx emissions factors in 40 CFR 60 Subpart IIII." DU believes that ADEC intended to require that the engines subject to 40 CFR 60 Subpart IIII shall comply with the applicable NOx emission standard in that rule.

Response:

The Department changed the word "factors" to "standards" to clarify the intent of the requirement.

Doyon Utilities Comment (10):

Table 3-11 of the proposed BACT Determination indicates that all of the small diesel-fired engines are subject to a numerical NOx emission limit. Section 7.7.8.3.1 of the proposed SIP document does not provide numerical emission limits for those engines not subject to 40 CFR 60 Subpart IIII. Please ensure that the underlying proposed BACT determination and the proposed SIP document are consistent to minimize possible confusion, and that the documents clearly state the compliance demonstration method.

Response:

The Department added Table 3-11 from the proposed BACT Determination Appendix into Section 7.7.8.3.1 of the SIP Control Strategies chapter to clarify the NOx emission limits for the small diesel-fired engines.

c. BACT for Fine Fraction Respirable Particulate Matter (PM2.5)

Doyon Utilities Comment (11):

Section 7.7.8.3.2 of the proposed SIP document and Section 4.1 of the proposed BACT Determination establish a PM-2.5 emission limit for EUs 1 through 6 of 0.006 pounds per million British thermal units (lb/MMBtu). ADEC has not provided a sound rationale for this determination and the PM-2.5 BACT emission limit. DU does not have PM-2.5 source test data for these boilers and is concerned that this limit may be unreasonably low, restrictive, and not achievable as a practical matter.

- **The basis for this limit is a source test for a different air pollutant.** The PM-2.5 BACT limit of 0.006 lb/MMBtu is based on one source test run from a three-run test conducted on EU 1 at Fort Wainwright in April 2017. This source test was an EPA Method 5 test, which measures filterable particulate matter (PM). PM includes all filterable particulate matter regardless of size. PM-2.5 includes filterable particulate matter with a nominal aerodynamic diameter of 2.5 microns or less. PM-2.5 also includes all condensable matter while PM does not include any condensable matter. The proposed BACT Determination states that the lowest PM-2.5 emission rate listed in the RBLC (RACT BACT LAER Clearinghouse database) is 0.012 lb/MMBtu. The BACT emission limit being imposed is an order of magnitude less than the lowest emission rate cited in the RBLC. No rationale or supporting engineering data are provided to justify this low emission limit, or to explain the reasons ADEC believes the limit is achievable.

- **The basis for this limit is one source test run on one boiler.** Relying on one run from one source test is an inappropriate method to establish an emission limit for any purpose. While DU appreciates that ADEC was attempting to select the worst-case run, using data from one run instead of the source test result is not appropriate or standard practice.

- If ADEC wished to rely on source testing to establish PM-2.5 limits for the coal-fired boilers, ADEC should have conducted or requested source testing for PM-2.5 emissions while adequate time was available to do so. Neither Section 7.7 of the proposed SIP document nor the underlying proposed BACT Determination explain the reasons the PM source test result is representative of the PM-2.5 emission rate. If the assumption is being made that PM-2.5 emissions from EUs 1 through 6 are less than or equal to PM emissions, this assumption should be supported (with source test results) to confirm that compliance with the limit can be achieved. Otherwise, please explain the rationale for selecting a PM-2.5 emission rate of 0.006 lb/MMBtu as the PM-2.5 BACT emission limit for EUs 1 through 6.

- In comments dated May 23, 2018, DU noted that the appropriateness of using a filterable PM emission limit to establish a PM-2.5 BACT limit had not been established. These comments were submitted to address the preliminary BACT Determination issued by ADEC in March 2018. ADEC does not appear to have considered this information in reaching the BACT determination. DU is requesting clarification from ADEC regarding whether the previously submitted information listed below was included in the BACT evaluation. If yes, DU is requesting clarification with respect how the information was considered. If no, DU is requesting clarification with respect to the reasons the information was not considered.

- During review of these proposed SIP elements, DU reviewed a spreadsheet file "Fbks_PtSrcs_2013-2019_Episode_Inventories_ToSLR.xlsm," described by Trinity Consultants as "A version of our comprehensive point source episodic EI calculation spreadsheet with 2013- 2019 EI data. This spreadsheet references facility specific spreadsheets with hourly episodic emission or fuel/throughput rates from the original 2008 episodes." In that spreadsheet, DU noted that ADEC and Trinity appeared to use a PM-2.5 emission factor of 0.697 pounds per ton of coal (lb/ton) to calculate PM-2.5 emissions from EUs 1 through 6 in certain tables. DU calculated this emission factor from data in Tables 1.1-5 and 1.1-6 in AP-42. The emission factor has been used to calculate potential assessable PM-2.5 emissions for EUs 1 through 6 in the two most recent Title V permit renewal applications (submitted in May 2013 and April 2019). The spreadsheet also includes tabs that show much lower PM-2.5 emission rates. DU is requesting clarification regarding the method used to calculate those lower rates and which emissions factors were used. BACT limits must be achievable in practice. As a result, DU requests that ADEC revisit the PM-2.5 BACT analysis using the appropriate available information to establish a PM-2.5 BACT limit that is well-supported with respect to being technically and economically feasible as well as achievable as a practical matter.

- The proposed SIP includes PM2.5 emission limits for EUs 7a, 7b, 7c, 51a, 51b and requires each EU to be source tested to demonstrate compliance. EUs 7a and 7c have been source tested previously but certain modification to the test method were needed due to space constraints. DU does not know whether the configurations of EUs 51 and 51b are conducive to conducting a PM2.5 source test.

Response:

The Department revised the PM2.5 BACT limit for the coal-fired boilers from 0.006 lb/MMBtu to 0.045 lb/MMBtu to more accurately represent the particulate emissions by including both condensable and filterable particulate matter. The Department calculated this numerical limit using the baghouse controlled emissions factors from AP-42 Tables 1.1-5 and 1.1-6 for spreader stoker boilers, as follows:

$$\left(\frac{0.04\ lb_{PM\ Total\ Condensable}}{MMBtu}\right)+\left[\left(\frac{0.01*A\ lb_{PM-2.5\ Filterable}}{ton_{coal}}\right)\times\left(\frac{ton_{coal}}{2000\ lb_{coal}}\right)\times\left(\frac{lb_{coal}}{7560\ Btu}\right)\times\left(\frac{10^6\ Btu}{MMBtu}\right)\right]=0.045\ lb/MMBtu$$

A = 7% Ash Content [38]

7560 Btu/lb coal [38]

The Department notes that 0.045 lb/MMBtu converts to 0.680 lb/ton of Usibelli coal. This is consistent with the equations used to calculate the PM2.5 emission factors in the two most recent Title V permit applications, using the typical gross as received heat value of 7,560 Btu/lb and an ash content of 7% for Usibelli coal.

The Department revised the compliance method for the material handling units (EUs 7a, 7b, 7c, 51a, and 51b) from conducting a source test to demonstrating compliance by following the fugitive dust control plan and the manufacturer's operating and maintenance procedures at all times of operation.

Doyon Utilities Comments (12 and 13):

Section 4.3 in the proposed BACT Determination has an inconsistent rationale for the BACT requirement to combust ultra-low sulfur diesel (ULSD) in large diesel-fired engines. (Specifically, this comment addresses privatized EU 8, the backup generator engine at the CHPP.)

- In Step 1(d), the use of low sulfur fuel is listed as an available and feasible emission control technology.

[38] http://usibelli.com/coal/data-sheet

- Step 2 states that all control technologies identified are technically feasible to control particulate emissions from large diesel-fired engines. DU notes that the use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing PM-2.5 emissions cannot be quantified.
- Step 3 does not address the use of ULSD.
- Step 5(d) requires the use of ULSD, with no supporting rationale or cost analysis.

Please make appropriate revisions to Section 4.3. DU understands that the requirement to combust ULSD will likely remain unchanged for the large diesel-fired engine. Specifically, the sulfur dioxide (SO_2) BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.3 will not eliminate the requirement to combust ULSD in the large diesel-fired engine. The combustion of ULSD is required in the large diesel-fired engines that are subject to 40 CFR 60 Subpart IIII.

Section 4.3 in the proposed BACT Determination does not provide a cost analysis to support the proposed PM-2.5 BACT determinations identified in Step 5 for large diesel-fired engines. Because each BACT determination must be based on technical and economic feasibility, the rationale for these proposed BACT determinations is incomplete, making the validity of the determinations questionable. Please include the required economic feasibility analysis.

Response:

The Department's rationale for selecting ULSD as one of the PM2.5 control requirements for privatized EU 8 is that it was proposed by the Army to control SO_2 emissions, and will also control PM2.5 emissions. Because the most effective PM2.5 control technology was selected (limited operation), a cost analysis is not required to be performed. Additionally, the Department agrees that Subpart IIII (federal emissions standards) requires EU 8 to combust ULSD and therefore constitutes a baseline emission rate (i.e., BACT floor). Therefore, ULSD must be included as a PM2.5 control technology and no substantive changes to Section 4.3 were made.

Doyon Utilities Comment (14):

Please include a statement in Section 4.3 of the proposed BACT Determination and Section 7.7.8.3.2 of the proposed SIP document to clarify that EU 8 shall demonstrate compliance with the numerical BACT emission limit by complying with the applicable PM emission standard in 40 CFR 60 Subpart IIII.

Response:

The Department did not change Section 4.3 of the BACT Determination or Section 7.7.8.3.2 of the SIP Control Strategies chapter. Step 5(f) of Section 4.3 of the BACT Determination requires the EUs to comply with the numerical BACT emission limits listed in Table 4.6 which specifies complying with the federal emission standards in 40 C.F.R. 60 Subpart IIII.

Doyon Utilities Comment (15):

Section 4.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(c), states that non-emergency operation of EU 8 is limited to “no more than 100 hours per year for maintenance checks and readiness testing.” This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6 of that permit). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised the limited operational requirement for EU 8 in Section 4.3 of the BACT Determination and Section 7.7.8.3.2 of the SIP Control Strategies chapter to clarify that EU 8 has the option to be converted to a non-emergency engine with a 500 hour per year limit, per Operating Permit AQ1121TVP02 Rev. 2.

Doyon Utilities Comment (16):

Table 4-9 in Section 4.4 of the proposed BACT Determination includes a PM-2.5 BACT limit of 0.03 grams per kilowatt-hour (g/kW-hr) for EUs 29a and 31a. This limit appears to reflect the EPA Tier 4 final PM emission standard. EUs 29a and 31a are both certified to EPA Tier 4 interim standards. The applicable Tier 4 interim PM standard is 0.3 g/kW-hr. Please revise Table 4-9 to reflect the appropriate emission limit for these Tier 4 interim-certified engines.

Response:

The Department revised Section 4.4 of the BACT Determination to correct the BACT emissions limit to 0.3 g/kW-hr to reflect the appropriate EPA Tier 4 interim PM emissions standard. The Department also made this change in the BACT Determination summary Table 6.2.

Doyon Utilities Comment (17):

Section 4.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(b), states that non-emergency operation of the small emergency engines is limited to “no more than 100 hours per year for maintenance checks and readiness testing.” Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised Section 4.4 of the BACT Determination and Section 7.7.8.3.2 of the SIP Chapter to clarify that the 100 hours per year limit is for non-emergency operations.

Doyon Utilities Comment (18):

Section 4.4 in the proposed BACT Determination has an inconsistent rationale for the BACT requirement to combust ultra-low sulfur diesel (ULSD) in small diesel-fired engines.

- Step 1 does not identify the use of low sulfur fuel or ULSD an available emission control technology.
- Step 3 ranks low sulfur fuel in the list of technically feasible control technologies. The use of low sulfur fuel is technically feasible, but the contribution of this technology toward reducing PM-2.5 emissions cannot be quantified.
- Step 5(a) requires the use of ULSD, with no supporting rationale or cost analysis.

Please make appropriate revisions to Section 4.4. DU understands that the requirement to combust ULSD will likely remain unchanged for the small diesel-fired engines. Specifically, the SO_2 BACT decision also requires the use of ULSD, so correcting this inconsistency in Section 4.4 will not eliminate the requirement to combust ULSD in the small diesel-fired engines.

Response:

The Department revised Section 4.4 to identify low ash/sulfur fuel as a control technology. Residual fuels and crude oil are known to contain ash forming components and primary sulfates, which are particulates. Therefore, the Department considers low ash/sulfur fuel a technically feasible particulate matter control technology (i.e., clean fuel).

Doyon Utilities Comment (19):

Section 4.4 in the proposed BACT Determination does not provide a cost analysis to support the proposed PM-2.5 BACT determinations identified in Step 5 for small diesel-fired engines. Because each BACT determination must be based on technical and economic feasibility, the rationale for these proposed BACT determinations is incomplete, making the validity of the determinations questionable. Please include the required economic feasibility analysis.

Response:

The Department revised Section 4.4 to identify limited operation as a technically feasible control technology and to clarify that the Army proposed limiting the operation of the engines to 500 hours per year (94% control). Additionally, ULSD was proposed by the Army to control SO_2 emissions, and will also control PM2.5 emissions. Because limited operation combined with ULSD was proposed by the Army, and is the most effective PM2.5 control technology, a cost analysis is not required to be performed.

Doyon Utilities Comment (20):

Section 7.7.8.3.2 of the proposed SIP document states that BACT for PM-2.5 emissions from the small diesel-fired engines includes the requirement that "for engines manufactured after the applicability dates of 40 CFR 60 Subpart IIII, comply with the applicable PM-2.5 emissions factors in 40 CFR 60 Subpart IIII." DU believes that ADEC intended to require that the engines subject to 40 CFR 60 Subpart IIII shall comply with the applicable PM emission standard in that rule. (The rule does not include PM-2.5 emission standards.)

Response:

The Department changed "PM-2.5" to "particulate matter" to clarify the applicable emission standards in 40 C.F.R. Subpart IIII.

Doyon Utilities Comment (21):

Table 4-9 of the proposed BACT Determination indicates that all of the small diesel-fired engines are subject to a numerical PM-2.5 emission limit. Section 7.7.8.3.2 of the proposed SIP document does not provide numerical emission limits for those engines not subject to 40 CFR 60 Subpart IIII. Please ensure that the underlying proposed BACT determination and the proposed SIP document are consistent to minimize possible confusion, and that the documents clearly state the compliance demonstration method.

Response:

The Department included Table 4-9 from the BACT Determination into the Control Strategies Section 7.7.8.3.2 to clearly identify the numerical BACT limits for the diesel-fired engines. The Department also included a bullet preceding the table to clarify that compliance with the limits will be demonstrated by maintaining records of maintenance procedures conducted in accordance with 40 C.F.R. Subparts 60 and 63, and by following the EU operating manuals.

d. BACT for Sulfur Dioxide (SO_2)

Doyon Utilities Comment (22):

In Section 5.1 of the proposed BACT Determination, Table 5.3 specifies SO_2 cost effectiveness for wet scrubbing and spray dry absorbers to be $20,673 per ton SO_2 removed and $21,211 per ton SO_2 removed, respectively. Although not explicitly stated, the proposed BACT Determination implies that these two technologies are not economically feasible and so are not SO_2 BACT. While DU has not evaluated the cost estimates for these control technologies, DU agrees that wet scrubbing and spray dry absorbers are not SO_2 BACT. As a result, comments addressing wet scrubbing or spray dry absorbers are not presented in this document.

The preliminary proposed SO_2 BACT is dry sorbent injection (DSI) which the proposed BACT Determination states at a capital cost of $14.5 million has a cost effectiveness of $10,329 per ton SO_2 removed. DU is concerned that the analysis is based on unsupported assumptions and use of a cost model that may not be appropriate for the size of the boilers.

As a result, DU contracted with Black and Veatch (B&V) to prepare a rough-order-of-magnitude cost estimate for a DSI system to be installed at DU's CHPP six boilers. B&V was selected not only because of their experience performing engineering services on projects in Alaska for electric utilities and the US military, but the fact that they are familiar with the CHPP as a result of a 2017/2018 Heat and Energy Study.

B&V used 0.25% coal sulfur content, assumed a building enclosure for all pieces of equipment, including the silos due to the cold Fairbanks temperatures, and developed capital costs for two different types of sorbent. Trona capital costs are less expensive than sodium bicarbonate, but ongoing operation costs are higher due to the higher sorbent injection rate and cost of sorbent delivery to Fairbanks. With the addition of owner costs, DU estimates that depending on the selected sorbent selection, initial capital costs can range between $26.1 and $31.6 million. This far exceeds ADEC's estimate of $14.5 million. DU's estimate is twice the ADEC cost estimate, and believes that SO_2 controls are not economic feasible.

In addition to the B&V analysis, DU provides the following comments on the SIP DSI analysis;

- Cost Model Validity: The economic analysis spreadsheet[39] containing the cost-effectiveness calculations for the proposed SO_2 BACT determination was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the calculations that are in Row 25 of the spreadsheet. The S&L white paper states that the model is intended to calculate estimated Total Project Cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent (in this case Trona) on a tons per hour (tph) basis and the gross generating capacity of the plant. The white paper omits information that is necessary to ensure that the spreadsheet is properly applied to a specific situation, including:
    - Types of plants to which the model is applicable (utility power generation, combined heat and power (CHP), cogeneration, other);
    - Applicable number of boilers (single unit or multi-boiler installation);
    - Applicable size range;
    - Equipment included in the Total Purchased Cost (TPC) calculation;

[39] 2019-05-10-adec-calculated-so2-economic-analysis-fort-wainwright-locked.xlsx

- On-site bulk storage capacity;
- A basis for selecting a “Retrofit factor” other than “1.0”; and
- Data and other information used to develop and support the equations used in the spreadsheet.

Based on review of the cost effectiveness model and the supporting documentation, determining the validity of the results of the analysis is not possible given the information that ADEC has made available in the public record. The concerns are rooted in three assumptions made by ADEC in preparing the cost model.

- ADEC assumed that the model is valid for a plant the size of DU’s Wainwright CHPP.
    - The calculation for “Base Module” cost (Row 30 of the spreadsheet) is based on an equation that uses the predicted sorbent demand. The S&L white paper states that the equation was developed based on “Cost data for several DSI systems.” No references or supporting information relating to these projects were provided. While the validity range for the equation was not identified, one piece of information gives some indication of the applicable range. Specifically, the equation has a discontinuity at 25 tph of sorbent flow. Given that the predicted total sorbent flow for all six coal-fired boilers at DU’s Wainwright CHPP is 1.5 tph, these boilers would be at the very bottom of the range of potential plant sizes. Without additional data to justify the cost calculation at very low sorbent injection rates, determining if the results of the equation are accurate is very difficult.
- The Preliminary Determination assumes that multiple boilers can accurately be modeled as a lumped heat input in a single spreadsheet.
    - The S&L white paper does not identify the type or configuration of the plant on which the calculation was based. Data input fields included in the spreadsheet (unit size, gross heat rate) indicate that the analysis was developed based on a single power generation unit (single boiler, single steam turbine, no CHP or cogeneration).
    - Based on the inputs to the spreadsheet provided by ADEC, EUs 1 thorough 6 are being treated as a single, lumped heat input value. This approach is an oversimplification and will not accurately account for the equipment and utilities that will be necessary to independently operate six boilers. The actual installation will require six separate trains of sorbent processing and transport equipment. Each train contains a day bin, mills, feeders, blowers, coolers, hoppers, piping, instrumentation, controls, electrical wiring and other supporting equipment. This need for separate systems complicates the design, increases overall footprint, and reduces the economy of scale that might be realized with a single larger unit. DU notes that the Retrofit Factor reflects a difficult retrofit in an attempt to account for this additional complexity.
    - DU also notes that adjusting the analysis to reflect the retrofit of one CHPP boiler (operated at full-load for 8,760 hr/yr) results in a cost-effectiveness value of greater than $35,000 per ton of SO_2 removed. That cost-effectiveness value is significantly greater than the $10,329 per ton removed presented in Section 5.1, Table 5-3 of the BACT Determination (Appendix III.D.7.07, pdf page 357 of 2309). BACT analyses are typically prepared for each emissions unit at a facility. While “grouping” emissions units is not necessarily unreasonable, a BACT analysis prepared for a group of emissions units must be proper and realistic. The S&L cost model does not appear to properly capture the emission control costs for EUs 1 through 6 as a group.

  - The sorbent feed rate currently calculated for EUs 1 through 6 is very low. Should the model be revised to calculate the cost effectiveness on a per unit basis, the feed rate would be roughly one sixth of the current value. This change would further amplify concerns about the accuracy of the TPC calculation.
- ADEC assumed that the model is valid for a heat and power plant.
  - As discussed above, no information is available addressing the type of plant on which the S&L spreadsheet is based. The assumption is that the plant is a single power generation unit. A CHP plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. In an effort to make the spreadsheet work for this application, ADEC used "dummy" data in the "Unit Size (Gross)" and "Gross Heat Rate" fields so that the calculated "Heat Input" field showed the maximum heat input value for EUs 1 through 6 (1,380 million British thermal units per hour (MMBtu/hr)). This approach has unintended consequences relating to the accuracy of the direct annual costs. The fixed and variable operating and maintenance (O&M) costs are evaluated on a per kilowatt and a per megawatt basis respectively. Utilizing a "dummy" gross generation number to calculate annual costs may not produce an accurate result. Based on review, no method exists to accurately model the direct annual costs for an installation such as the DU EUs 1 through 6 by using the S&L spreadsheet.
  - The average maximum hourly heat input identified in Row 15 of the spreadsheet is incorrect. The value shown reflects the maximum hourly heat input for each of the boiler. The value does not account for the permitted annual coal consumption limit. If the coal consumption limit is considered, the maximum hourly heat input is reduced to 583 MMBtu/hr averaged over a year. A reduction in hourly heat input will have an impact on the overall cost effectiveness calculation, but given the concerns with the calculation itself, identifying the specific impacts is difficult.

- SO_2 Emission Rates: The SIP uses two different SO_2 emission rates. The preliminary BACT determination states that the SO_2 emission rate used in the spreadsheet to calculate the total annualized operating costs was based on 0.2 weight percent (wt. pct.) sulfur coal and AP-42 emission factors. This approach resulted in an emission rate of 0.46 pounds of SO_2 per MMBtu (lb SO_2/MMBtu) heat input. This value is significantly different than the effective emission rate for the plant based on the PTE established in Title V Permit AQ1121TVP02, Revision 2. The effective emission rate is calculated as follows:

  Permitted PTE: 1,764 tons of SO_2
  Permitted coal consumption limit: 336,000 tpy
  Assumed coal energy content: 7,600 British thermal units per pound (Btu/lb)

  1,764 tons SO_2/yr * 1 year/336,000 tons coal * 1 lb coal/7,600 Btu * 10^6 Btu/MMBtu * 1 ton coal/2,000 lb coal * 2,000 lb SO_2/ton
  = 0.691 lb SO_2/MMBtu

- The difference between the ADEC-assumed emission rate and the effective emission rate leads to a significant discrepancy in the SO_2 cost effectiveness calculation. The ADEC spreadsheet divides the total annualized cost (determined by using the 0.46 lb/MMBtu SO_2 rate) by the SO_2 PTE (with an effective rate of 0.691 lb/MMBtu). The use of two different emission rates in this calculation results in an invalid comparison of two values that should not be compared to each other. For the result of the equation to be valid, the total annualized cost must be calculated using an SO_2 emission rate equal to the SO_2 PTE.

- Conclusion: Based on the review of the proposed SO_2 BACT determination and the associated cost effectiveness calculation, no indication could be found that the proposed BACT Determination calculation accurately reflects the actual operating conditions for EUs 1 through 6.

If a more accurate cost effectiveness is to be determined, the cost effectiveness should be recalculated using a bottom-up cost estimating approach based on actual plant conditions. These conditions would include SO_2 emission rates based on current PTE, permit constraints (where applicable and enforceable), available space, ambient conditions, and local factors such as construction logistics, labor wage rates, and local sorbent costs.

Response:

The Department acknowledges that DU is concerned that the cost analysis is based on unsupported assumptions and the use of a cost model that may not be appropriate for the size of the boilers. However, absent a detailed engineering study and cost quotations from system suppliers, any control technologies successfully implemented nationwide will be considered technologically and economically feasible. See 40 CFR 51.1010(a)(3), 81 FR 58081-85.

The Department also acknowledges that DU obtained a rough order-of-magnitude cost estimate from Black and Veatch for a DSI system to be installed at the FWA CHPP. Black and Veatch indicate in its July 22, 2019 Memorandum that retrofitting the six coal-fired boilers would require an initial capital cost of roughly $20.1 million dollars with an operating cost of approximately $2.3 million dollars per year (See Attachment A to this RTC for the Black and Veatch Estimate).

However, the Army also provided a cost estimate from Amerair Industries LLC that indicates it will design, fabricate, and supply the DSI system and all associated equipment for the price of $2.8 million dollars (See Attachment B to this RTC for the Amerair Estimate). Additionally, the Army's BACT analysis calculated a total cost of 6.2 million dollars for installation of DSI with a calculated cost of $4,500/ton to $6,000/ton SO_2 *removed, for the 80% and 50% control efficiency cases, respectively.*

Therefore, based on the two aforementioned cost estimates and this comment, the Department revised the cost effectiveness calculation for retrofitting the coal-fired boilers to include dry sorbent injection and finds the cost estimate ***does not*** *result in an adverse economic impact (emphasis added). The Department revised its assumptions to represent an increased sulfur content of the coal to 0.25% by weight, adjusted the current bank prime interest rate of 5.0%, and dropped the heat input rate to the 23 MW, which is the size of one of the six boilers at the CHPP. The new Department calculated cost per ton of* SO_2 *removed is $11,383, which is considered to be cost effective for a BACT control in the Serious non-attainment area.*

Doyon Utilities Comment (23):

In Section 5.1 of the proposed BACT Determination, the proposed requirement for the coal sulfur content to be no greater than 0.2 weight percent is not evaluated using the five-step BACT process, or even identified as an available control technology in Step 1. (All coal mined at the Usibelli Coal Mine meets the definition of “low sulfur coal,” which is coal with a sulfur content of less than one percent sulfur. The low sulfur coal is considered in Step 1(d).) The current coal sulfur content is not limited beyond the State SIP SO_2 standard and the requirement to determine what the SO_2 emission concentrations would be prior to combusting coal with a sulfur content of greater than 0.4 weight percent. (Refer to Conditions 11 and 11.1 of Permit AQ1121TVP02, Revision 2.) Imposing this limit without first preparing a proper BACT analysis is not appropriate. If this requirement is to be imposed as a limit without a proper BACT analysis to justify the limit, then the limit should be used to calculate a revised baseline emission rate. The BACT analysis should then calculate any further emission reductions based on that revised baseline emission rate.

DU does not agree that the coal sulfur content assumption of less than or equal to 0.2 weight percent is appropriate. More investigation is needed to determine whether this assumption is valid and feasible. The 0.2 weight percent coal sulfur limit should be assessed through the BACT analysis process. Step 1(d) of the proposed BACT Determination acknowledges that the current contract guarantee is less than 0.4 weight percent sulfur, and that the coal typically ranges from 0.08 to 0.28 weight percent sulfur.

DU does not procure coal used in the DU CHPP, but is expected to support the Department of Defense’s preference to maintain a 90 day coal stockpile in the interests of energy security for Fort Wainwright. The existing 90 day coal storage pile at the CHPP includes coal with a variety of sulfur contents because coal is added to and removed from the pile over a period of years. The sulfur content of the coal pile is not certain to be less than 0.2 weight percent throughout the pile. If the final BACT requirements specify a coal sulfur content less than that currently specified contractually between the Army and Usibelli Coal Mine, please provide a limit to require that any future deliveries of coal meet the sulfur content specification as opposed to limiting the sulfur content of all coal being combusted at the DU CHPP. The coal pile at the DU CHPP is primarily an emergency storage pile and use of that stockpiled coal should not be restricted.

The Serious SIP was silent on how the sulfur content of coal was to be reported or considered within a regulatory context. The standard operating permit condition should remain the same and that facilities continue to have available the sulfur content of each shipment of fuel.

Response:

The Department acknowledges that the 0.2 percent sulfur content limit wasn’t included as part of the BACT determination and therefore didn’t go through EPA’s top-down evaluation process. Instead it was established in the Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department’s need to ensure no backsliding occurs and therefore acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into DU's air quality permit. The Department used this 0.25% by weight sulfur content to recalculate the cost effectiveness for installing SO_2 controls on the coal-fired boilers at Fort Wainwright, see the Department's response to the previous comment for more details.

Requiring the change in sulfur content to be implemented on an as-delivered-basis will allow the coal already stockpiled at Fort Wainwright to be utilized, ensuring the Department of Defense's preference to maintain a 90 day coal stockpile in the interests of energy security.

Doyon Utilities Comment (24):

Section 5.1 of the proposed SIP document appears to present language for a possible compliance order by consent (COBC) between ADEC and FWA that would impose requirements on the DU CHPP emissions units. The document does not explain how (or whether) a COBC between ADEC and the Army would ultimately apply to DU or the DU-owned emissions units. The language in the proposed COBC does not distinguish between the entire CHPP and EUs 1-6, and addresses the additional BACT for the large diesel-fired engines or the source testing or the PM2.5 emission limits for EUs 7a, 7b, 7c, 51a, 51b and requires each EU to be source tested to demonstrate compliance.

Response:

The Department has removed all references to a possible COBC between the Department and the Army from the SIP Control Strategies chapter.

Doyon Utilities Comment (25):

Section 7.7.8.3.3 of the proposed SIP document is unclear as to whether the 0.2 weight percent sulfur limit is a BACT limit or proposed as a requirement in the COBC, or both. If the 0.2 weight percent sulfur limit is intended to be a BACT limit, a BACT analysis was not prepared for this control technology. The underlying BACT Determination does not include a BACT limit requiring the use of coal with a sulfur content less than 0.2 weight percent.

Response:

The previously proposed coal sulfur limit of 0.2 percent by weight has been increased to 0.25 percent by weight. This requirement is not a BACT requirement, but rather a requirement of the SIP. To differentiate between the BACT requirements and the final determinations required by the SIP, the Department has moved the final determinations section in the SIP's Control Strategies Chapter to the beginning of the section for each source. Fort Wainwright's requirement to limit coal deliveries to 0.25 percent by weight is now summarized in the table in Section 7.7.8.3 of the SIP Control Strategies chapter.

Doyon Utilities Comment (26):

Section 5.3 in the proposed BACT Determination for large diesel-fired engines, specifically Step 5(d), states that non-emergency operation of EU 8 is limited to "no more than 100 hours per year for maintenance checks and readiness testing." This requirement is inconsistent with Title V Permit AQ1121TVP02, Revision 2 which allows EU 8 to be converted to a non-emergency engine with a limit of 500 hours per year. (Please refer to Conditions 24.3 through 24.6). Please revise this requirement to clarify that the limit applies only while the engine is classified as an emergency engine, and that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII, which allows 100 hours per year of non-emergency operation but does not restrict those non- emergency operations to maintenance checks and readiness testing. (Please refer to Condition 23.3c of AQ1121TVP02, Revision 2 and 40 CFR 60.4211(f)(3).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised the limited operational requirement for EU 8 in Section 5.3 of the BACT Determination and Section 7.7.8.3.3 of the SIP Chapter to clarify that EU 8 has the option to be converted to a non-emergency engine with a 500 hour per year limit, per Operating Permit AQ1121TVP02 Rev. 2.

Doyon Utilities Comment (27):

Section 5.4 in the proposed BACT determination for small diesel-fired engines, specifically Step 5(c), requires maintaining good combustion practices. The determination that good combustion practices is BACT should be eliminated or a rationale should be provided for selecting good combustion practices in addition to the combustion of ULSD and limited operations. Per Table 5-10 in Section 5.4, good combustion practices were not determined to be SO_2 BACT for small diesel-fired engines at another stationary source. While DU follows good combustion practices as a standard practice, Step 3(c) indicates that good combustion practices are the least effective SO_2 emission control technology.

Response:

The Department is not removing good combustion practices (GCP) from Section 5.4 because it finds that it is a reasonable control technology and identified in numerous locations in both the Control Strategies chapter of the SIP, the BACT Determination, and other PSD permits approved by the Department. While not explicitly identified in the RBLC Summary Table 5-9, a search of RBLC will yield multiple results of GCP being selected as BACT for diesel fired engines. Additionally, the Department had previously selected GCP as an SO_2 BACT control for the small diesel-fired engines located at the Fairbanks Campus Power Plant (UAF) and inadvertently did not include it in Fort Wainwright's BACT Comparison Table 5-10.
Table 5-10 now includes GCP, Limited Operation, and Ultra-Low Sulfur Diesel for both Fort

Wainwright and UAF as SO_2 controls for small diesel-fired engines.

Doyon Utilities Comment (28):

Section 5.4 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(a), states that non-emergency operation of the small emergency engines is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. (Please refer to Conditions 23.3c and 30.3 of AQ1121TVP02, Revision 2, 40 CFR 60.4211(f)(3), and 40 CFR 63.6640(f).) Please align the BACT requirements to be consistent with the existing applicable permit requirements and ensure that Section 7.7.8.3.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT Determination.

Response:

The Department revised Section 5.4 of the BACT Determination and Section 7.7.8.3.3 of the SIP Chapter to clarify that the 100 hours per year limit is for non-emergency operations

2. Comments from the United States Army Garrison Alaska

U.S. Army Comment (1): Section 7.7.8.3 Fort Wainwright

Please reword the sentence: "The EUs located within the military installation at Fort Wainwright Central Heating and Power Plant (CHPP) are operated by a private utility company, Doyon Utilities, LLC. (DU) and owned by the U.S. Army Garrison Fort Wainwright (FWA)" to "EUs located within the military installation include units such as boilers and generators that are owned and operated by the U.S. Army Garrison Alaska (FWA). The FWA Central Heating and Power Plant (CHPP), also located within the installation footprint, is owned and operated by a private utility company, Doyon Utilities, LLC (DU)."

The current wording suggests that DU operates all of the emission units {EUs) located within the installation footprint, which is misleading and inaccurate. DU also owns the CHPP, not Fort Wainwright. U.S. Army Garrison Fort Wainwright is now United States Army Garrison Alaska.

Response:

The Department made a technical correction to Section 7.7.8.3 of the SIP Chapter to clarify that the EUs at the CHPP is owned and operated by Doyon Utilities, LLC.

U.S. Army Comment (2): Section 7.7.8.3 Fort Wainwright, applies throughout the section

Several emission units were transferred between DU and Fort Wainwright at the beginning of

2019. The following corrections should be made to accurately reflect EU ownership and which entity has requirements to comply with: DU EU 10 is now FWA EU 50; DU EU 11 is now FWA EU 51; DU EU 12 is now FWA EU 52; DU EU 13 is now FWA EU 53; DU EU 15 is now FWA EU 54; DU EU 16 is now FWA EU 55; DU EU 17 is now FWA EU 56; DU EU 18 is now FWA EU 57; DU EU 19 is now FWA EU 58; DU EU 20 is now FWA EU 59; DU EU 21 is now FWA EU 60; DU EU 24 is now FWA EU 61; DU EU 25 is now FWA EU 62; DU EU 26 is now FWA EU 63; DU EU 27 is now FWA EU 64; and DU EU 28 Is now FWA EU 65.

Response:

The Department revised the emissions unit inventory to reflect the transfer of the EUs from DU to the Army.

U.S. Army Comment (3): Section 7.7.8.3.1 NOx Controls for Fort Wainwright, Last Paragraph

"Limit EU 8 to 500 hours of operation per year." Please clarify which EU 8 is being referred to here: FWA EU 8 or DU EU 8?

Response:

The Department made changes to the SIP Chapter 7.7.8.3.3, and BACT Determination Section's 3.3, 4.3, and 5.3 to clarify that DU EU 8 is the diesel-fired engine with a 500 hours per year operating limit.

U.S. Army Comment (4): NOx Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright Best Available Control Technologies (BACT) Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building Identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Response:

The Department revised the BACT determination and Control Strategies SIP chapter to remove the 500 hour per year limits from the small diesel-fired boilers, since these units are not emergency boilers. As described in the BACT sections, the unrestricted potential to emit for the boilers is relatively small and would not result in additional controls being cost effective.

U.S. Army Comment (5): Section 7.7.8.3.2 PM2.5 Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright BACT Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Response:

The Department revised the BACT determination and Control Strategies SIP Chapter to remove the 500 hour per year limits from the small diesel-fired boilers, since these units are not emergency boilers. As described in the BACT sections, the unrestricted PTE for the boilers is relatively small and would not result in additional controls being cost effective.

U.S. Army Comment (6): Section 7.7.8.3.3 SO_2 Controls for Fort Wainwright

"Limit non-emergency operation of the 27 diesel fired boilers, with the exception of the waste-fuel boilers, to no more than 500 hours per year, for maintenance checks and readiness testing."

In reviewing this requirement, there is a misstated assumption in the Fort Wainwright BACT Analysis that states that the boilers are emergency boilers. The only emergency boilers in use on Fort Wainwright are EUs 8, 9, and 10. All other boilers in the emissions inventory are considered insignificant emission sources and are not used for emergency purposes, as they are the primary heating source at their designated building identifier. Limiting boilers to 500 hours would affect Army readiness and create problems with maintaining mission important infrastructure during seasonally cold temperatures.

Response:

The Department revised the BACT determination and Control Strategies SIP Chapter to remove the 500 hour per year limits from the small diesel-fired boilers, since these units are not emergency boilers. As described in the BACT sections, the unrestricted PTE for the boilers is relatively small and would not result in additional controls being cost effective.

U.S. Army Comment (7): Section DEC BACT DETERMINATION for Fort Wainwright Central Heating and Power Plant

Based on a review of the control package and the BACT analyses for the other two coal fired facilities located in the nonattainment area, the economic feasibility argument finding should equitably apply to all coal fired facilities in the nonattainment area. There is no articulated argument stating why the Fort Wainwright CHHP is required to have additional controls or why it is dissimilar to the other coal power plants that are subject to the same requirements. The Fort Wainwright CHHP is a coal fired plant with the same or similar processes as the Chena Power Plant and the UAF Power Plant, and would be subject to the same proposed coal sulfur limitations. Studies completed by EPA in 2016, as highlighted in Vol. II: 111.D.7.8 Modeling document, states that wood smoke contributes between 60-80% of the fine particulate matter found on filters during the winter months, while major sources contribute less than 10%. Installation of costly controls on an aging facility may that have little to no influence on the air quality in the nonattainment area, where wood smoke is identified as the major primary contributor.

Additionally, Fort Wainwright is assessing future energy usage based on aging infrastructure and is developing plans for improvement or replacement of current utilities, which has a projected timetable of less than 15 years. As such, Fort Wainwright requests that an Economic Infeasibility determination be applied to the Fort Wainwright CHHP.

Response:

Consistent with the BACT Determination for Fort Wainwright, the BACT Determinations for the Chena Power Plant and UAF Campus Power Plant identify SO_2 and NOx BACT controls for the coal fired boilers at these sources. The NOx controls proposed in these determinations are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. The Department assumes EPA will approve this precursor demonstration.

Regarding the economic infeasibility finding for Chena Power Plant and UAF Campus Power Plant stated in the Control Strategies SIP chapter, these sources provided financial indicators to the Department contending that they cannot afford the control technologies demonstrated to be economically feasible in the BACT Determinations. As stated in the PM2.5 implementation rule:

> *"If a source contends that a source specific control-level should not be established because the source cannot afford the control measure or technology that is demonstrated to be economically feasible for other sources in its source category, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators, to the extent applicable:*
>
> *(1) Fixed and variable production costs ($/unit)*
>
> *(2) Product supply and demand elasticity*
>
> *(3) Product prices (cost absorption vs. cost pass-through)*
>
> *(4) Expected costs incurred by competitors*
>
> *(5) Company profits*
>
> *(6) Employment costs*
>
> *(7) Other costs (e.g., for RACM implemented by public sector entities)."*

The Department acknowledges that the majority of PM2.5 found on the filters during high particulate matter days in the winter months are a result of wood smoke, but this does not obviate the requirement under the Clean Air Act to conduct BACT analyses on point sources that emit more than 70 tons per year of PM2.5 or for any individual PM2.5 precursor (NOx, SO_2, NH_3, VOCs). These sources are subject to site-specific review for BACT.

3. Comments from the United States Air Force (USAF)

<u>USAF Comments (1 and 2):</u>

On 14 May 2019, the Alaska Department of Environmental Conservation (ADEC) released the Serious Area State Implementation Plan (SIP) for the Fairbanks North Star Borough (FNSB) Fine Particulate (PM2.5) Nonattainment Area (NAA) for public review. Public comments are due by 5:00 p.m. on 26 July 2019. The Air Force appreciates the opportunity to comment on the SIP and the collaborative effort with the ADEC to provide a means to attain the PM2.5 24-hour standard.

Although Eielson Air Force Base in not within the NAA, Eielson shares a coal contract with Fort Wainwright Army Garrison for coal obtained from Usibelli Coal Mine (UCM). The Air Force has the following comment on the sulfur content of coal.

a) In Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.7.07 and in the Best Available Control Technology (BACT) Summary Highlight located at http://dec.alaska.gov/media/16232/bact-summary-highlight-051419.pdf the proposed BACT for coal sulfur content is 0.2 percent sulfur by weight. This sulfur limit will cut off access to tens of millions of tons of coal from UCM as well as pose a potential threat of fuel supply interruption for the coal-fired power plant using UCM coal.

b) The Air Force requests ADEC adopt a BACT coal-sulfur content of 0.25 percent sulfur by weight based on a semi-annual weighted average of coal-sulfur content in shipments of coal within the semi-annual period corresponding to Facility Operating Report reporting period.

c) The ADEC has proposed that BACT for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2 percent sulfur by weight. UCM is the only source of commercial coal available to the coal-fired boiler facilities within the Fairbanks North Star Borough fine particulate nonattainment area. The mine has limited ability to affect the sulfur content in the coal. There is not a coal washing or segregating facility associated with UCM which could ensure a consistent coal- sulfur concentration. Current practice for providing low-sulfur coal to their customers is identifying sulfur content of the resource through drilling and sampling efforts. However, the ability to characterize the sulfur content of the coal mined is limited.

> Within the millions of tons of coal resources available to UCM, there is a significant amount of coal with higher sulfur content than 0.2 percent by weight; in fact, any limit proposed to the coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. As such, the Air Force proposes that the coal-sulfur content limit be lowered to 0.25 percent by weight on an as received basis (wet) as opposed to 0.2 percent by weight as proposed by ADEC. The increase in coal sulfur content will help with coal accessibility and availability over the next decade.
> The state was silent on how the measure was to be reported or considered within a regulatory context. The ADEC's standard permit condition for coal fired boilers (Standard Condition XIII) requires that the permittee report sulfur content of each shipment of fuel with the semi-annual Facility Operating Reports. UCM currently provides a semi-annual report to all customers which includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the operating reports' reporting period. The Air Force proposes that the standard operating permit condition remain the same, and that facilities continue to provide the 'State with the sulfur content of each shipment of fuel; in addition, the weighted average coal-sulfur content of the shipments received by the facility during the reporting period would be referenced in the operating report.

<u>Response:</u>

The Department is requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. The sources identified in the SIP Control Strategies Chapter that use coal will be required to submit an application to apply for an air permit to include the new coal sulfur content limit. The Department is not intending to change Standard Permit Condition XIII to implement this change.

GVEA North Pole Power Plant and Zehnder Facility Response to Comments

Table of Contents

1. Comments from Golden Valley Electric Association (GVEA)

a. BACT requirements for SO2 Comments

GVEA Comment (1):

Fuel Cost Assumptions, High Sulfur Diesel to Ultra Low Sulfur Diesel

In November 2018 GVEA supplied actual fuel costs incurred between January 2017 and October 2018 which showed a cost differential of $0.424 per gallon between No. 2 HSD and ULSD. This was an increase from the differential cost of $0.2668 per gallon incurred between August 2015 and April 2016 as presented in GVEA's 2017 proposed BACT. The updated differential fuel cost was not applied in the cost effectiveness calculations shown in the draft SIP. GVEA requests the use of the $0.424 per gallon cost differential in cost effectiveness calculations for North Pole EU IDs 1 and 2, and for Zehnder EU IDs 1 and 2.

Response:

The Department adjusted the ULSD cost differential in the BACT economic analyses for the turbine EUs 1 and 2 at both the North Pole and Zehnder Facilities using the information provided by GVEA in November 2018. GVEA's November 2018 submission showed cost differences from No. 2 HSD to ULSD at the North Pole Facility of approximately $0.424 per gallon and approximately $0.251 per gallon at the Zehnder Facility. The Department used the actual fuel cost difference reported for the Zehnder Facility instead of using the North Pole Facility's fuel cost as an estimate, because site-specific cost information is more accurate.

GVEA Comment (2):

Fuel Cost Assumption, LSR Naphtha to Ultra Low Sulfur Diesel

On page III.D.7.7-65, in the review of GVEA's proposed cost effectiveness for converting from LSR Naphtha to ULSD for North Pole EU IDs 5 and 6 ADEC notes it "does not agree that the cost effectiveness should be based upon the annual cost of USLD, but on the difference in cost between the current fuel and ULSD."

In November 2018 GVEA submitted actual fuel cost data with the differential cost between LSR Naphtha and ULSD. That cost differential of $1.117 per gallon was used in the cost effectiveness calculations GVEA submitted. GVEA requests the use of the $1.117 per gallon cost differential in cost effectiveness calculations for North Pole EU IDs 5 and 6.

Response:

The Department removed the paragraph from the SIP Chapter and the BACT Report that stated "The Department does not agree that the cost effectiveness should be based upon the annual cost of USLD, but on the difference in cost between the current fuel and ULSD." The

Department removed this paragraph because using the cost differential of the two fuels was how GVEA performed the cost effectiveness economic analysis. The Department updated Section 7.7.8.5.3 of the SIP Control Strategies chapter and Section 5.2 of the BACT Determination document using the $1.117 per gallon cost differential between LSR Naphtha and ULSD for both GVEA's and the Department's cost effectiveness calculations.

Additionally, the Department updated its economic analysis to also include the SO_2 emission reductions from switching 1.5 million gallons of gas turbine fuel 1-GT (Jet A/LAGO) with a sulfur content of 0.3 percent by weight used during startup to ULSD with a sulfur content of 0.0015 percent by weight. The addition of switching the gas turbine fuel 1-GT and the LSR fuel to ULSD equates to approximately 33 tons per year of SO_2 removed per turbine at a cost of $1,040,822 per ton, which was deemed cost ineffective.

GVEA Comment (3):

Cost Effectiveness

Using the updated fuel pricing increases the cost per ton of SO_2 removed for all primary North Pole and Zehnder generating units from that presented in the draft SIP. Table 1 shows the costs effectiveness presented in November of 2018 compared with the draft SIP cost effectiveness. Table 1 also shows GVEA's proposed cost effectiveness using ADEC's proposed interest rate of 5.5% and the differential fuel costs.

Table 1. Cost Effectiveness $/Ton of SO_2 removal Conversion to ULSD			
	GVEA's 2018 Alternative BACT Cost Effectiveness ($/Ton)	ADEC's 2019 Draft SIP Cost Effectiveness ($/Ton)	GVEA's Draft SIP Comments Cost Effectiveness ($/Ton)[40]
North Pole			
EU ID 1	$13,942	$9,060[41]	$14,225
EU ID 2	$14,037	$9,147[42]	$14,347
EU ID 5/6	$4,844,020[43]	$9,282,151	$4,844,020
Zehnder			
EU ID 1/2	$14,250	$9,620[44]	N/A[45]

When applying the differential cost of $0.424 per gallon, GVEA proposes that it is not economically feasible to switch to ULSD for any of the generating units listed in Table 1 in either the short or the long term.

Response:

The Department updated the methodology used to calculate cost effectiveness for North Pole Power Plant's EUs 1 and 2 using the cost differential of $0.424 per gallon for switching to ULSD as suggested. The Department calculated a similar dollar amount for the switch to ULSD for EUs 1 and 2 of $13,838 and $13,923 respectively. The Department considers these values to be cost effective when taking into account the actual reduction in SO_2 that will be realized by the fuel switch in the Serious nonattainment area.

GVEA Comment (4):

North Pole Emission Units (EUs) ID 5 and 6 Fuel Sulfur Limit.

As presented in the November 2018 submittal, GVEA currently receives all fuel from Petro Star Inc. (PSI) with the majority coming from the local North Pole Refinery adjacent to the North Pole

[40] Using an interest rate of 5.5% applied to the cost effectiveness calculations GVEA submitted in 2018, North Pole - Section 5 - SO_2_F_181121_ADEC_GVEA.xlsm. Note that the North Pole capital costs include all fuel storage capital costs under the assumption that a SO_2 emission limit on Zehnder is taken.
[41] ADEC references $9,060 in the SIP text and $9,138 in the file D7.07-appendix-chapter-707-northpole- so2-controls-economic-analysis-2019 (1).xlsx
[42] ADEC references $9,147 in the SIP text and $9,233 in the file D7.07-appendix-chapter-707-northpole- so2-controls-economic-analysis-2019 (1).xlsx
[43] GVEA's proposed cost effectiveness is lower based on a 50ppm sulfur limit for LSR Naphtha fuel as discussed in Comment 3
[44] ADEC references $9,060 in the SIP text and $8,960 in the file D7.07-appendix-chapter-707-zehnder- so2-controls-economic-analysis-2019 (1).xlsx
[45] GVEA's proposed BACT takes a SO_2 emission limit for Zehnder, removing it from consideration as a major source.

Power Plant. In 2017 the combined cycle turbine at North Pole (EU ID 5) began receiving a Light Straight Run (LSR) Naphtha product directly from the Petro Star North Pole Refinery (PSI) via pipeline. The sulfur content of this fuel was specified to be below 30 ppm and extensive testing conducted in 2018 showed a maximum sulfur content of 27 ppm. Less than two percent of the fuel received is composed of other Naphtha fuels that have sulfur contents greater than 50 ppm. Assuming a maximum fuel sulfur content of 50 ppm would conservatively change the potential SO_2 emissions from EU ID 5 and proposed EU ID 6 from 6 to 10.1 tons per year (TPY). GVEA requests a maximum fuel sulfur content of 50 ppm for EU IDs 5 and 6, the draft SIP uses 30ppm.

Response:

The Department revised the sulfur content limit in the BACT determination and Control Strategies chapter to reflect that the Light Straight Run (LSR) Naphtha can exceed 30 ppm. The Department included the 50 ppm sulfur content limit for the LSR Naphtha in EUs 5 and 6 to represent a BACT limit that is achievable as a practical manner.

GVEA Comment (5):

North Pole Emission Units (EUs) ID 1 and 2 No. 1 HSD

ADEC has proposed SO_2 BACT for North Pole EU IDs 1 and 2 as the combustion of No. 1 HSD on Air Quality Stage 1 and Stage 2 curtailment days (page III.D.7.7-68). GVEA appreciates ADEC's consideration of GVEA's alternative BACT proposal and requests the BACT be worded to "take delivery of No. 1 HSD on Air Quality Stage 1 and 2 curtailment days." No. 2 and No. 1 HSD is delivered to North Pole EU IDs 1 and 2 by truck from PSI's North Pole refinery. The fuel is stored in an intermediate 50,000 gallon storage tank and it requires an estimated 5 to 10 hours of run time to fully transition between fuels. To meet the requirement of combusting only No. 1 HSD during Air Quality alerts, GVEA would have to construct additional fuel storage. Also, as discussed in the November 2018 submittal, the availability of No. 1 HSD is unknown with competing requirements. If PSI is unable to meet demand for home heating, military, and electrical generation use, the fuel will be trucked in at a cost differential similar to ULSD. For reliability purposes, GVEA wishes to maintain the ability to run these units in the event No. 1 HSD is not available.

The draft SIP proposes selective use of No. 1 HSD as short term BACT, and ULSD or Natural Gas as long term BACT. As discussed in comment 3 above, when using the differential costs submitted by GVEA in November 2018, GVEA proposes ULSD is not economically feasible as long term BACT. Likewise, natural gas is not yet available, and only EU IDs 5 or 6 would be configurable to combust natural gas.

Response:

The Department revised the SIP Control Strategies chapter to allow the fuel switch for EUs 1 and 2 to occur by taking delivery of fuel oil with a sulfur content no greater than 1,000 ppmw (S1000) immediately after the Air Quality Stage Alert 1 and 2 are announced and remain taking deliveries of exclusively S1000 for as long as the air episode exists.

Additionally, to ensure the Department has a SIP which can be federally approved, North Pole EUs 1 and 2 will be required to combust diesel fuel with a sulfur content no greater than 15 ppmw (ULSD) during the winter months (October 1 through March 31) no later than October 1, 2023.

GVEA Comment (6):

Future Considerations

GVEA wishes to add clarification to items presented under the Future Considerations discussion in both sections 7.7.8.4.3 SO_2 Controls for Zehnder and 7.7.8.5.3 SO_2 Controls for North Pole.

a) Switching to Natural Gas - GVEA is exploring options that may assist the Interior Gas Utility (IGU) in providing economical natural gas to the Fairbanks and North Pole areas. If economically feasible, GVEA would consider converting North Pole's EU ID 5, or constructing EU ID 6, to combust natural gas. This would replace an already low sulfur fuel (50 ppm) and would not provide much benefit in SO_2 reduction associated with electrical generation. It could however, benefit the community by stabilizing demand and providing an economy of scale that may make natural gas more attractive to the home heating sector. EU IDs 1 and 2 at both North Pole and Zehnder would not be converted to combust natural gas.

Response:

The Department encourages GVEA to explore the commercial availability and economic feasibility of conducting a fuel switch to natural gas, which may assist the Interior Gas Utility (IGU) in providing economical natural gas to the Fairbanks area. The Department is providing for the ability to switch to natural gas, so long as the overall SO_2 emissions are equivalent to or less than the overall PTE resulting from the fuel switch to ULSD and LSR Naphtha.

b) Closing Operations - GVEA has not suggested "closing the operations at the North Pole and Zehnder Plants and operating at Healy Units 1 and 2". The availability of all generating plants is important to maintain GVEA's ability to reliably supply electrical power to the interior. The use of EU IDs 1 and 2 at North Pole and EU IDs 1 and 2 at Zehnder has dropped significantly since Healy Unit 2 came into commercial operation in September of 2018. The consumption of fuel in the NAA by these units will drop by 50% with the addition of Healy Unit 2 to the generation fleet.

Response:

The Department removed the discussion about the possibility of GVEA closing the North Pole Power Plant and Zehnder Facility from the SIP Control Strategies Chapter under both the North Pole and Zehnder Future Considerations sections.

c) SCR on Healy Unit 2 - The SCR on Healy Unit 2 has been fully installed and commissioned so is no longer a consideration in future planning efforts.

Response:

The Department removed both references to installing SCR on Healy Unit 2 from the SIP Chapter's Future Considerations section for GVEA's Zehnder Facility and North Pole Power Plant.

GVEA Comment (7):

Zehnder SO_2 BACT and SO_2 Requirements

The proposed SO_2 BACT for EUs 1, 2, 3, 4, 10, and 11 is a requirement to combust only ULSD fuel. The proposed SIP document then also includes a requirement for GVEA to submit a Title I permit application on or before October 31, 2019, to limit the potential emissions of SO_2 from Zehnder to less than 70 tons per year. The document does not clearly address the relationship between the ULSD fuel requirement and the permit limit for facility SO_2 potential emissions. Based on Section 189(e) of the Clean Air Act, the intent appears to be that the ULSD requirement would only apply if GVEA does not submit a permit application to limit potential emissions of SO_2. GVEA proposes BACT is the Zehnder facility potential emissions of SO_2 without a restriction on fuel type or sulfur content.

Response:

The Department has modified the SIP Control Strategies chapter to clarify that the SO_2 BACT limit for the Zehnder Facility is to submit an application by June 9, 2020 that limits SO_2 emissions to less than 70 tons per year. The Department has changed the layout in the SIP Control Strategies chapter to include a table in the beginning of each stationary source section that includes a summary of significant BACT and SIP findings. Note that this table specifies the Zehnder Facility is required to submit an application to limit SO_2 *emissions as BACT.*

b. Other Comments, North Pole Plant

GVEA Comment (8):

a) North Pole, Emissions Units (EUs) 1 and 2 – Simple Cycle Gas Turbines

i) The proposed NOx BACT determination states that ADEC has revised the PTE for EU 2 based on the most recent source test data. The emission rate that ADEC is using for baseline PTE is 1.39 lb/MMBtu. Previously, PTE has been calculated using an emission factor of 0.88 lb/MMBtu from AP-42.

ii) The proposed NOx BACT determination uses a NOx removal efficiency of 90 percent for selective catalytic reduction (SCR), but states that "removal efficiencies are generally 80 to 90 percent." No engineering rationale is provided for use of the maximum removal efficiency.

iii) Monitoring, recordkeeping, and reporting requirements are not specifically provided for EUs 1 and 2, other than conducting an initial source test to demonstrate compliance with the NO_x emission limit and that fuel receipts or test results for sulfur content shall be used to demonstrate compliance with the fuel sulfur content limit.

Response:

The Department erroneously stated that EU 2 had performed a source test with a NOx emission rate of 1.39 lb/MMBtu when in fact no source test was performed on that EU. Therefore, the Department revised the cost effectiveness calculations for EU 2 using the AP-42 emission rate of 0.88 lb/MMBtu for distillate oil-fired turbines.

The Department has updated the language used in Section 3.1 of the BACT Report removing the statement that "removal efficiencies are generally 80 to 90 percent." That language has been replaced with updated language from Chapter 2 of the June 2019 edition of EPA's Cost Control Manual for SCR[46], which states:

> *"Theoretically, SCR systems can be designed for NOx removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own."*

Based on this EPA guidance and the fact that the turbines at the North Pole Power Plant do not already have NOx controls such as low NOx burners, the Department is maintaining the 90 percent NOx removal efficiency for the turbines.

Monitoring, recordkeeping, and reporting requirements are not included in the BACT Reports for any of the facilities. Instead, the existing air quality permits at these facilities will need to be modified to include this information.

b) North Pole, EUs 5 and 6 – Combined Cycle Gas Turbines

i) The proposed NOx BACT determination uses a NOx removal efficiency of 90 percent for SCR, but states that "removal efficiencies are generally 80 to 90 percent." No engineering rationale is provided for use of the maximum removal efficiency.

ii) Monitoring, recordkeeping, and reporting requirements are not specifically provided for EUs 5 and 6, other than conducting an initial source test to demonstrate compliance with the NOx emission limit and that fuel receipts or test results for sulfur content shall be used to demonstrate compliance with the fuel sulfur content limit.

[46] https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

Response:

The Department is maintaining a 90 percent NOx emission control for the use of SCR on the combined cycle turbines. See the Department's response to Comment 8a for this rationale. Monitoring, recordkeeping, and reporting requirements are not included in the BACT Reports for any of the facilities. Instead, the existing air quality permits at these facilities will need to be modified to include this information.

c) North Pole, EU 7 – Emergency Generator Engine

i) Monitoring, recordkeeping, and reporting requirements are not specifically provided for EU 7, other than that fuel receipts or test results for sulfur content shall be used to demonstrate compliance with the fuel sulfur content limit.

Response:

Monitoring, recordkeeping, and reporting requirements are not included in the BACT Reports for any of the facilities. Instead, the existing air quality permits at these facilities will need to be modified to include this information.

d) North Pole, EUs 11 and 12 - Boilers

i) The requirement to install low NOx burners assumes a control efficiency of 80 percent. No rationale is provided for this efficiency.

ii) Fuel receipts or test results for sulfur content shall be used to demonstrate compliance with the propane sulfur content limit. The sulfur content of the propane fuel may not be something typically provided by the vendor or otherwise readily available.

Response:

The Department revised the control efficiency of Low NOx Burners (LNBs) for the propane boilers to 70% control to account for uncertainties associated with applying an 80% control efficiency to an AP-42 emission factor with an emission factor rating of E. Also the Department's evaluation of the EPA Cost Control Manual for SCR which states that. "The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu)." SCR is known to achieve a lower emission rate than LNBs. The resulting NOx BACT limit for the propane-fired boilers is 0.045 lb/MMBtu.

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Regarding the compliance demonstration for the sulfur content of propane, the Department *revised Step 5 of the SO_2 BACT section to indicate that "Compliance with the emission rate limit will be demonstrated with fuel shipment receipts that indicate that propane was the fuel that was delivered."*

c. Other Comments, Zehnder Facility

GVEA Comment (9):

a) Zehnder, Emissions Units (EUs) 1 and 2 – Combustion Turbines

i) The proposed SIP documents do not include a source testing requirement for the engines to demonstrate compliance with the emissions limit for PM2.5. The BACT documents do not state that source testing is required to demonstrate compliance with the limit. The BACT documents do not appear to provide any specific compliance demonstration requirements.

ii) Monitoring, recordkeeping, and reporting requirements are not specifically provided for EUs 1 and 2, other than conducting an initial source test to demonstrate compliance with the NOx emission limit and that fuel receipts or test results for sulfur content shall be used to demonstrate compliance with the fuel sulfur content limit.

Response:

The Department has revised the SIP Chapter and BACT Report to clarify that the initial compliance demonstration with the PM2.5 BACT emission limit for the Zehnder Facility's EUs 1 and 2 will be completed via a source test. To maintain consistency, the Department also included an initial source test requirement in the SIP Chapter and the BACT Report to demonstrate compliance with the PM2.5 BACT emission limit for the North Pole Power Plant's turbines EUs 1, 2, 5, and 6.

Monitoring, recordkeeping, and reporting requirements are not included in the BACT Reports for any of the facilities. Instead, the existing air quality permits at these facilities will need to be modified to include this information.

b) Zehnder, EUs 3 and 4 – Large Diesel-Fired Engines

i) Non-emergency operation is limited to no more than 100 hours per year for each engine. The documents are not clear whether non-emergency operation is restricted solely to maintenance checks and readiness testing, or if the 50 hours per year of non-emergency operation for other reasons as allowed in the federal rules is still available.

ii) The proposed SIP documents do not include a source testing requirement for the engines to demonstrate compliance with the emissions limits for NOx and PM2.5. The BACT documents do not state that source testing is required to demonstrate compliance with the limits. The BACT documents do not appear to provide any specific compliance demonstration requirements.

iii) Monitoring, recordkeeping, and reporting requirements are not specifically provided for EUs 3 and 4, other than that fuel receipts or test results for sulfur content shall be used to demonstrate compliance with the fuel sulfur content limit.

Response:

The Department revised the BACT determinations for emergency engines EUs 3 and 4 to clarify that the 100 hours per year limit is not solely for maintenance checks and readiness testing. This allows flexibility and maintains consistency with the applicable requirements under 40 C.F.R. 60 Subpart IIII and 40 C.F.R. 63 Subpart ZZZZ.

The Department revised the SIP Chapter and BACT Report to clarify that EUs 3 and 4 will demonstrate compliance with the numerical NOx and PM2.5 BACT emission limits by complying with 40 C.F.R 63 Subpart ZZZZ.

The Monitoring, recordkeeping, and reporting requirements are not included in the BACT Reports for any of the facilities. Instead, the existing air quality permits at these facilities will need to be modified to include this information.

c) Zehnder, EUs 10 and 11 - Boilers

i) The proposed SIP documents do not include a source testing requirement for the boilers to demonstrate compliance with the emissions limits for NOx and PM2.5. The BACT documents do not state that source testing is required to demonstrate compliance with the limits. The BACT documents do not appear to provide any specific compliance demonstration requirements.

ii) Monitoring, recordkeeping, and reporting requirements are not specifically provided for EUs 10 and 11, other than that fuel receipts or test results for sulfur content shall be used to demonstrate compliance with the fuel sulfur content limit.

Response:

The Department revised the SIP Chapter and BACT Report to clarify that EUs 10 and 11 will demonstrate compliance with the numerical NOx and PM2.5 BACT emission limits by complying with 40 C.F.R 63 Subpart JJJJJJ.

Monitoring, recordkeeping, and reporting requirements are not included in the BACT Reports for any of the facilities. Instead, the existing air quality permits at these facilities will need to be modified to include this information.

d. Summary

GVEA appreciates ADEC's consideration of alternative BACT solutions and requests the following modifications to proposed SO_2 controls in the draft SIP based on information previously submitted by GVEA in November 2018.

The differential fuel cost of $0.424 per gallon between HSD and ULSD and $1.117 per gallon between LSR Naphtha and ULSD make the switch to ULSD economically infeasible as short term or long term BACT for all primary generating units at the North Pole Plant and Zehnder Facility.

For North Pole EU IDs 1 and 2, GVEA proposes to take delivery of No. 1 HSD and will transition to the combustion of No. 1 HSD during periods of Air Quality Stage 1 and Stage 2 curtailment periods, on the condition that No. 1 HSD is locally available.

For North Pole EU IDs 5 and 6, GVEA proposes to combust fuels with a sulfur content of 50 ppm or less.

For Zehnder EU IDs 1, 2, 3, 4, 10, and 11, GVEA proposes to submit a Title I permit application limiting the potential SO2 emissions to less than 70 tons per year, except in emergency situations, without limiting the type of fuel or fuel sulfur content.

2. Additional Changes Made by the Department

The Department updated the BACT Determination Tables 4-7 and 6-2 for the diesel-fired engine EU 7 to include limited operation and positive crankcase ventilation as PM2.5 BACT controls, which were already specified as BACT in Section 4.3.

UAF Campus Power Plant Response to Comments

Table of Contents

1. Comments from the University of Alaska Fairbanks (UAF)

a. Environmental, Health, Safety, and Risk Management General Comments

UAF Comment (1):

In several instances, the Best Available Control Technology (BACT) limits presented in the proposed SIP document and the BACT Determination are inconsistent with respect to emissions limits and other requirements not only with each other but within themselves. Because both documents will become part of the SIP, obtaining clarity on exactly which requirements will be applicable to each emissions unit is essential to ensure compliance.

Response:

The Department included tables from the BACT Determination into the SIP Control Strategies chapter Section 7.7.8.6.1 to clearly identify the numerical BACT limits for the diesel-fired engines. The Department also included a bullet preceding the table to clarify that compliance with the limits will be demonstrated by maintaining records of maintenance procedures conducted in accordance with 40 C.F.R. Subparts 60 and 63, and the EU operating manuals.

UAF Comment (2):

Inadequate technical information is provided in the BACT Determination. This lack of information generally includes, but is not limited to, the following areas.

- Little or no engineering data or rationale is provided to support the Alaska Department of Environmental Conservation (ADEC) determinations addressing whether an emission control technology is or is not technically feasible.
- Little or no engineering data, cost data, or rationale is provided to support the determinations addressing whether an emission control technology is or is not BACT.
- The methodology used to determine emissions reductions is typically not quantified.

This lack of data and rationale is not consistent with ADEC past insistence that the stationary sources provide a substantial level of detail and specific engineering data to support the BACT analyses the stationary sources submit to ADEC.

Response:

The Department disagrees that inadequate technical information was provided in the BACT determination for the source. It is the responsibility of the applicant performing the BACT analysis to provide adequate engineering data, cost data, and clearly identify the rationale needed for providing a basis on which the reviewing agency can confirm decisions on the technical infeasibility of control options. Additionally the applicant should review the most recent regulatory decisions and determinations to establish what the performance levels for a *control technology should be.*

<u>UAF Comment (3):</u>

In many cases, the BACT Determination does not identify the methods that must be used to verify compliance with the BACT limits. The methods to be used for verifying compliance should be identified so that the Permittees can determine whether the methods that ADEC intends to require are appropriate and whether the methods will be overly cumbersome and/or expensive.

<u>Response:</u>

The Department included Table 3-17 from the BACT Determination into the SIP Control Strategies chapter Section 7.7.8.6.1 to clearly identify the numerical BACT limits for the diesel-fired engines. The Department also included a bullet preceding the table to clarify that compliance with the limits will be demonstrated by maintaining records of maintenance procedures conducted in accordance with 40 C.F.R. Subparts 60 and 63, and the EU operating manuals.

<u>UAF Comment (4):</u>

Throughout both documents listed above, there is inconsistency in the pollutant sections as to how:

- Identification of the emission units (e.g. small diesel-fired engines PM 2.5; the SIP addresses only EU ID 27, while the BACT Determination addresses EU IDs 23, 24, 26, 28, and 29); and
- Emission units and their BACT requirements are listed (e.g. table or bullets)

UAF suggests being consistent in both areas and would appreciate that the emission units are identified in the title of the section (e.g. Mid-Sized Diesel-Fired Boilers - EU IDs 3 and 4).

<u>Response:</u>

The Department made changes to the SIP Control Strategies chapter to ensure consistency with the BACT Determination document. BACT Determination Tables 3-17 and 4-14 containing BACT limits for NOx and PM2.5 for the small diesel-fired engines were included in the Control Strategies Chapter of the SIP. The Department used bullets to list EU BACT requirements in both documents except for cases of multiple different EUs with different emission limits, which includes NOx and PM2.5 from the small diesel fired engines and PM2.5 from the material handling units. Additionally, the Department included the EU numbers in the title of each of UAF's EU sections of the SIP Control Strategies chapter, as was already the case in the BACT Determination document.

UAF Comment (5):

Small Diesel Engines: UAF is requesting that ADEC remove the BACT analysis/discussion in the draft SIP and the BACT Determination for the following emission units: EU IDs 23, 24, 26, 28, and 29. In a letter dated August 14, 2015 from Alice Edwards regarding UAF PM 2.5 Serious Nonattainment BACT Protocol Response, Item 3.b, EPA's informal comments indicated that a Serious Area BACT analysis is only required for permitted emission units (letter attached). The EU IDs mentioned in sentence 1 of this paragraph are not permitted units. UAF has left comments in this document regarding these units in case we are unaware of changes to the protocol.

Response:

The Department did not remove EUs 23, 24, 26, 28, and 29 from the BACT Determination because they are included in the emissions unit inventory for the source via the Title V permit application shield. These units are included in the draft operating permit and therefore should be included in the Serious Area BACT Determination.

b. EHSRM – BACT Determination for Nitrogen Oxides (NOx) Comments

Dual Fuel-Fired Boiler, Emissions Unit (EU) ID 113

UAF Comment (6):

If NOx BACT is required, the proposed BACT for the Combined Heat and Power Plant (CHPP) dual fuel-fired boiler, EU ID 113, is Selective Catalytic Reduction (SCR). The proposed NOx emission limit is 0.02 pounds per million British thermal units (lb/MMBtu) averaged over three hours. The proposed SIP document and BACT determination do not provide engineering design data supporting the emission limit for this boiler. The calculation of the emission limit is based on a 90 percent reduction in NOx emissions compared to the baseline. A 90 percent reduction is the typical maximum emission reduction that can be expected from the use of SCR. No specific engineering information is presented that demonstrates a 90 percent reduction is achievable for EU 113. Please provide this supporting information in the final BACT Determination.

Response:

The Department revised the cost effectiveness calculation (i.e., BACT emission rate) using an 80 percent reduction for NOx control with SCR to downward adjust the emission rate consistent with the cost control manual which indicates that a NOx emission rate of 0.02 lb/MMBtu is likely unachievable. With an 80 percent control efficiency, the calculated BACT limit is equal to 0.04 lb/MMBtu.

From the EPA Cost Control Manual. "Theoretically, SCR systems can be designed for NOx removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, *the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu)."*

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

UAF Comment (7):

UAF does not agree with ADEC's of the estimate of cost for adding the SCR to EU ID 113. UAF's Cost Effectiveness for SCR is calculated at $28,425 per ton of NOx removed. Please provide additional information in the appendices of this document of how ADEC calculated the $6,197 per ton of NOx reviewed to support this number which is 21.7 percent of the UAF calculation. Also note that the BACT determination lists the cost effectives at $22,232 in Table 3-2.

Response:

The Department acknowledges that UAF's cost effectiveness calculation in Table 3-2 for EU 113 should have been $28,425 per ton of NOx removed with SCR and revised the value accordingly.

The Department does not agree with UAF's cost effectiveness calculation for installing SCR on EU 113. The Department notes that UAF provided a $6 million estimate for "SCR budgetary material cost" from the boiler manufacturer Babcock & Wilcox (B&W). However, there was never a site specific quote for SCR installation on EU 113 provided to the Department and we find it unlikely that the SCR installation cost would be double the SCR purchase price of $6 million dollars. This assumption was based on a proposal by Fuel Tech which for study purposes (± 30%), stated the cost of installation of SCR on the mid-sized diesel fired boilers would be approximately 2.0 times the capital cost of $850,000 dollars.

Absent a detailed engineering study and cost quotations from system suppliers, the Department used the spreadsheet included in the June 2019 edition of EPA's Cost Control Manual for SCR to calculate the cost effectiveness for installing SCR using an 80 percent control efficiency resulting in an achievable BACT limit of 0.04 lb/MMBtu, at a new cost effectiveness value of $6,638/ton. The original spreadsheet used to calculate SCR cost effectiveness assumed a 90% reduction from an uncontrolled baseline NOx emission rate of 0.2 lb/MMBtu (NSPS floor). However, this would result in a final emission rate of 0.02 lb/MMBtu and, as stated in Section 4 Chapter 2 of the EPA Air Pollution Control Cost Manual, "the outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu)."

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for *the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.*

UAF Comment (8):

Although Section 3.1 of the BACT Determination indicates that NOx BACT control proposed for EU ID 113 is SCR, good combustion practices, circulating fluidized bed (CFB), and staged combustion. Table 6-1 of the same document indicates that NOx BACT for the unit is fabric filters. Please clarify the correct BACT control methodology for this unit.

Response:

The Department erroneously included fabric filters in Table 6-1 of the BACT Determination for NOx controls on EU 113. The Department has corrected this mistake and the table now states that SCR and good combustion practices are the proposed BACT control for NOx emissions.

Dual Fuel-Fired Boiler and Mid-Sized Diesel-Fired Boiler, EU IDs 3 and 113

UAF Comment (9):

The economic analysis spreadsheet[47] is a cost estimation spreadsheet used to support the SCR BACT determination. This cost model was developed by Sargent & Lundy (S&L) but may not be an appropriate model for costs pertaining to EU IDs 3 and 113. Additionally, the inputs to the cost model may not be appropriate or adequate to properly determine costs.

Based on review of the cost effectiveness model and the supporting documentation, determining the validity of the results of the analysis is not possible. The concerns are rooted in two assumptions made by ADEC in preparing the cost model.

- *ADEC assumed that the model is valid for a plant the size of UAF CHPP.*
  The S&L SCR Cost Development Methodology[48] white paper dated January 2017 addresses several caveats which do not appear to be addressed in the BACT Determination. The white paper states that "the costs for retrofitting a plant smaller than 100 megawatts (MW) increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units." EU ID 113 has a maximum heat input rate of 295.6 MM Btu/hr which is an equivalent maximum input of approximately 88.7 MW. EU ID 3 has a maximum heat input rating of 180.9 MM Btu/hr which is an equivalent maximum input of approximately 54 MW. The output ratings, which is what was likely used in the S&L calculations, will be even lower.

- *ADEC assumed that the model is valid for a heat and power plant.*
  No information is available addressing the type of plant on which the S&L spreadsheet

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[47] 2019-05-10-adec-calculated-scr-eu113-economic-analysi s-uaf.xlsm

[48] https://www.epa.gov/sites/production/files/2018-05 /documents/attachment_5-3_scr_cost_development_methodology .pdf

is based. The assumption is that the plant is a single power generation unit. A combined heat and power (CHP) plant differs significantly from a "traditional" power plant in that the steam produced in a CHP plant is not exclusively used to generate electricity. UAF is unable to confirm that the direct annual costs can be accurately modeled for an installation such as EU IDs 3 and 113 by using the S&L spreadsheet

Response:

The Department acknowledges that UAF is concerned that the cost analysis is based on unsupported assumptions and the use of a cost model that may not be appropriate for the size and design of EUs 3 and 113. However, absent a detailed engineering study and cost quotations from system suppliers, any control technologies successfully implemented nationwide will be considered technologically and economically feasible. See 40 CFR 51.1010(a)(3), 81 FR 58081-85.

The Department did not use the cost model developed by Sargent and Lundy for estimating SCR costs pertaining to the dual fuel-fired boiler (EU 113). Rather, it used EPA's 2016 SCR Cost Manual Spreadsheet.[49] *As indicated in the Read Me tab of this spreadsheet, it can be used to estimate capital and annualized costs for applying SCR to coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour. As indicated in UAF's comment, "EU ID 113 has a maximum heat input rate of* ***295.6 MM Btu/hr*** *which is an equivalent maximum input of approximately 88.7 MW." (emphasis added). Regarding the type of plant for which the spreadsheet is based (traditional vs. combined heat and power), "the size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs."* [37]

For EU 3, the Department revised UAF's cost analysis for the installation of SCR using a NOx control efficiency of 80%, an interest rate of 5.0%, and a 20 year equipment life.

For EU 113, the Department calculated the cost effectiveness for installing SCR on the 295.6 MMBtu/hr boiler using a baseline emission rate of 0.2 lb NOx/MMBtu (NSPS floor), an average retrofit difficulty factor of 1.0, a NOx removal efficiency of 80%, an interest rate of 5.0% (current bank prime interest rate), and a 20 year equipment life.

The resulting cost effectiveness values for installation of SCR NOx controls for EUs 3 and 113 are $7,033/ton and $6,638/ ton of NOx removed, respectively. For additional information see the UAF SCR Economic Analysis Spreadsheets in Appendix III.D.7.07 to the Control Strategies Chapter on the Fairbanks Serious SIP website at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip/.

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has

[49] https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm

included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Mid-Sized Diesel-Fired Boiler, EU ID 3

UAF Comment (10):

The BACT Determination and proposed SIP document indicate a BACT NOx limit of 0.02 lb/MMBtu for the mid-sized diesel-fired boiler, EU ID 3. This BACT limit was calculated based on a 90 percent reduction in NOx emissions compared to the baseline. A 90 percent reduction is the typical maximum reduction that can be expected from the use of SCR. No specific engineering information is presented demonstrating that a 90 percent reduction is achievable for EU ID 3.

The BACT determination, documented in Table 3-5, indicated that there was no control specified for firing diesel. Although the permit allows for the burning of natural gas (NG), EU ID 3 does not currently have the capability to burn NG. Please provide additional information as to why ADEC believes the SCR should be placed on EU ID 3.

Response:

For EU 3, the Department revised UAF's cost analysis for the installation of SCR using a NOx control efficiency of 80%, an interest rate of 5.0%, and a 20 year equipment life.

Absent a detailed engineering study and cost quotations from system suppliers, the Department used the spreadsheet included in the June 2019 edition of EPA's Cost Control Manual for SCR to calculate the cost effectiveness for installing SCR using an 80 percent control efficiency resulting in an achievable BACT limit of 0.04 lb/MMBtu, at a new cost effectiveness value of $7,033/ton. The original spreadsheet used to calculate SCR cost effectiveness assumed a 90% reduction from an uncontrolled baseline NOx emission rate of 0.2 lb/MMBtu. However, this would result in a final emission rate of 0.02 lb/MMBtu and, as stated in Section 4 Chapter 2 of the EPA Air Pollution Control Cost Manual, "the outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu)." Therefore, the Department used 0.04 lb/MMBtu as a BACT limit that is achievable as a practical manner.

While not explicitly identified in the RBLC Summary Table 3-5, a search of RBLC will yield multiple results of SCR being selected as BACT for diesel fired boilers. Additionally, UAF's BACT analysis provided a Fuel Teck vendor proposal that identified SCR as a technically feasible control technology for EU 3.

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Small Boilers, EU IDs 19 through 21

UAF Comment (11):

The BACT NOx limits for the small boilers, EU IDs 19 through 21 list are inconsistent in the BACT Determination. That BACT Determination indicates a BACT NOx limit of 0.15 lb/MMBtu in Step 5 page 16 and Table 3-11. While Table 6-1 in the BACT Determination indicates a BACT NOx limit of 0.015lb/MMBtu. Please clarify the correct BACT NOx limit for these emissions units. Please note that the proposed SIP document includes a BACT NOx limit of 0.15 lb/MMBtu on page 72.

Response:

The Department corrected the NOx emission limit for EUs 19 through 21 in Table 6-1 of the BACT Determination document to 0.15 lb/MMBtu, which matches the limit specified in Step 5, Table 3-11, and the SIP Control Strategies chapter.

Large Diesel-Fired Engine, EU ID 8

UAF Comment (12):

UAF proposed a BACT NOx emission limit from the large diesel-fired engine, EU ID 8, of 0.0195 grams per horsepower-hour (g/hp-hr) without the use of SCR. ADEC proposed a higher emission limit of 1.3 g/hp-hr, but requires the use of SCR at all times of operation. An economic analysis for the use of SCR was not provided. Because each BACT determination must be based on technical and economic feasibility, the economic rationale for the proposed BACT control of SCR is incomplete, making the validity of the determination questionable. Because a lower NOx emission rate can be achieved without the use of SCR, UAF believes that the use of SCR is not economically feasible and should not be required.

Response:

The Department acknowledges that the 13,000 hp engine has not consistently run with SCR operating to lower NOx emissions. However, a search of RBLC will yield multiple results of SCR being selected as BACT for diesel-fired engines (as identified in Table 3-12). Absent a cost analysis demonstrating that SCR is not cost effective, the most effective NOx control demonstrated in practices must be selected as BACT for the engine. Additionally, as identified in Footnote 11 a February 2002 source test identified that EU 8 was operating with SCR.

The Department notes the NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC has included with this Serious SIP, a final precursor demonstration as justification not to require NOx controls.

Small Diesel-Fired Engines, EU IDs 24, 28, and 29

UAF Comment (13):

ADEC proposes a BACT NOx emission limit of 0.3 g/hp-hr for the small diesel-fired engine, EU ID 29, per BACT determination Table 3-17. The stated rationale for this limit is that EU ID 29 is a certified engine. EU ID 29 is certified as an EPA Tier 4i engine, which has an NOx emission limit for an engine rated at 314 horsepower (hp) (234 kilowatts (kW)) of 2.0 grams per kilowatt-hour (g/kW-hr) (1.5 g/hp-hr). The BACT NOx emission limit proposed by ADEC is inconsistent with the EPA Tier 4i NOx emission limit for the rating and model year corresponding to EU ID 29. Please explain this inconsistency or revise Table 3-17 to reflect the appropriate BACT NOx emission limit for EU ID 29.

Response:

The Department corrected the NOx emission limit for EU 29 in Tables 3-17 and 6-1 of the BACT Report to 1.5 g/hp-hr, the proper EPA Tier 4i engine emission factor under 40 C.F.R. 1039.102(e)(2) (converted to g/hp-hr).

UAF Comment (14):

Section 3.5 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(c), states that non-emergency operation of the small emergency diesel-fired engines, EU IDs 24, 28, and 29, is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart 1111 and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. Please ensure that Section 7.7.8.6.1 of the proposed SIP document is revised for consistency with the underlying proposed BACT determination.

Response:

The Department revised the BACT determinations for emergency engines in Section 7.7.8.6.1 of the SIP Chapter and Section 3.5 of the BACT Report to clarify that the 100 hours per year limit is not solely for maintenance checks and readiness testing. This allows flexibility and maintains consistency with the applicable requirements under 40 C.F.R. 60 Subpart IIII and 40 C.F.R. 63 Subpart ZZZZ.

c. BACT Determination for Fine Fraction Respirable Particulate Matter (PM2.5)

Small Boilers, EU IDs 19 through 21

UAF Comment (15):

The BACT PM2.5 limits for the small boilers, EU IDs 19 through 21 are inconsistent within the BACT Determination. Step 5 - Selection of PM-2.5 BACT for the small Diesel-Fire Boiler, (b) and Table 4-8 of the BACT Determination indicates a BACT PM2.5 limit of 0.012 lb/MMBtu. Table 6-2, page 62 of that document indicates a BACT PM 2.5 limit of 7.06 g/MMBtu (0.016 lb/MMBtu). Please clarify the correct BACT limit for these emissions units. Please note that the proposed SIP document, Page 75, includes a BACT PM2.5 limit of 0.012 lb/MMBtu.

Response:

The Department corrected the PM2.5 emission limit for EUs 19 through 21 in Table 6-2 of the BACT Report to 0.012 lb/MMBtu, which matches the limit specified in Step 5, Table 4-8, and the SIP Chapter.

Small Diesel-Fired Engines, EU IDs 23, 24, and 26 though 29

UAF Comment (16):

UAF proposes EU ID 27 meet the Federal Emission standard (EPA Tier 3) to control PM 2.5 emissions of 0.2 g/kW-hr or 0.15 g/hp-hr. Page 77 of the proposed SIP document indicates a BACT PM 2.5 limit of 0.11 g/hp-hr. It is unclear how ADEC determined that UAF would meet the lower PM 2.5 emission standard on this EPA approved engine. Please clarify in the SIP and BACT Determination how the 0.11g/hp-hr was derived.

Response:

The Department corrected PM2.5 emission limit for EU 27 in Tables 4-14 and 6-2 of the BACT Determination and Section 7.7.8.6.3 of the SIP Control Strategies chapter to 0.15 g/hp-hr, the proper EPA Tier 3 engine emission factor under 40 C.F.R. 89.112(a) (converted to g/hp-hr).

UAF Comment (17):

The proposed BACT control methodology for the small engine, EU ID 27, is inconsistent within the BACT Determination. Page 43 of the BACT Determination lists limited operation and good combustion practices, whereas Page 65 Table 6-2 also includes the use of a turbocharger and aftercooler on the engine. No economic analysis is provided to support the use of a turbocharger and aftercooler on the engine. Please clarify that the correct BACT control methodology for this emissions unit is limited operation and good combustion practices.

Response:

The Department removed the erroneous reference to a turbo charger and aftercooler required as a PM2.5 emission control device on EU 27 in Tables 4-14 and 6-2 of the BACT Determination. The correct PM2.5 emission control technology for EU 27 is limit operation to 4,380 hours per 12-month rolling period and good combustion practices.

UAF Comment (18):

Section 4.5 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(b), states that non-emergency operation of the small emergency diesel-fired engines, EU IDs 24, 28, and 29, is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart 1111 and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. Please ensure that Section 7.7.8.6.2 of the proposed SIP document is revised for consistency with the underlying proposed BACT determination.

Response:

The Department revised the BACT determinations for emergency engines in Section 7.7.8.6.2 of the SIP Control Strategies chapter and Section 4.5 of the BACT Determination document to clarify that the 100 hours per year limit is not solely for maintenance checks and readiness testing. This allows flexibility and maintains consistency with the applicable requirements under 40 C.F.R. 60 Subpart IIII and 40 C.F.R. 63 Subpart ZZZZ.

d. BACT Determination for Sulfur Dioxide (SO2)

Dual Fuel-Fired Boiler, EU ID 113

UAF Comment (19):

Page 86 of the proposed SIP document indicates that ADEC does not find installation of Dry Sorbent Injection (DSI) to be economically feasible for the dual fuel-fired boiler, EU ID 113. UAF understands and agrees with the determination that DSI is not required because UAF has demonstrated that DSI is not affordable. However, installation of DSI is indicated as BACT in both the BACT Determination and on Page 79 of the proposed SIP document. Please indicate in the BACT Determination and Page 79 of the proposed SIP document that installation of DSI is not required for clarity.

Response:

The Department has re-worked the layout of the SIP Control Strategies chapter to more clearly state the requirements. Section 7.7.8.6 of the SIP Control Strategies chapter now leads off with a

DEC BACT and SIP Findings Summary Table for Fairbanks Campus Power Plant. This table is the decision made by the Department and does not include DSI for EU 113. This reflects the Department's finding that, due to the financial indicators provided by UAF and as allowed for under the PM2.5 Implementation Rule, UAF is not required to install DSI for the dual fuel-fired boiler at the Fairbanks Campus Power Plant. Therefore, the existing NSPS Subpart Db emission limit or 0.20 lb/MMBtu will be retained for the dual fuel-fired boiler. While the Department finds that it is economically infeasible for UAF to implement retrofit SO_2 controls on the dual fuel-fired boiler at the Fairbanks Campus Power Plant, it must still include for nonattainment BACT purposes, that DSI is considered a technically and economically feasible SO_2 control technology for EU 113.

UAF Comment (20):

Page 86 of the proposed SIP document indicates that UAF would be required to limit sulfur content of coal to 0.2 percent sulfur by weight (wt. pct. S) by June 9, 2021. ADEC did not identify this proposed requirement as an available SO_2 emission control option and did not evaluate this proposed requirement using the five-step BACT process. The current coal sulfur content is not limited beyond the State SIP SO_2 standard. Imposing this limit without first preparing a proper BACT analysis is not appropriate. Even if 0.2 wt. pct sulfur coal is available from any source, ADEC has not prepared an economic feasibility analysis to determine whether this requirement is BACT.

Response:

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT Determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the SIP Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into UAF's air quality permit. The Department used this 0.25% by weight sulfur content to recalculate the cost effectiveness for installing SO_2 controls on the coal-fired boilers at UAF.

Requiring the change in sulfur content to be implemented on an as-delivered-basis will allow the coal already stockpiled at UAF to be utilized and ensure a continuous supply of coal is available.

UAF Comment (21):

The BACT SO_2 emission limit for the dual fuel-fired boiler, EU ID 113, is listed as 0.10 lb/MMBtu/hr in the BACT Determination and the proposed SIP document. ADEC indicates in Footnote 22 of the BACT Determination that this limit was selected after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from coal-fired boilers in Alaska and actual emissions data from other sources. The cited source tests and emissions data are not available for review and no supporting engineering data is provided to justify this low emissions limit. Please provide the reasons that ADEC believes this SO_2 emission limit is technically and economically feasible and is achievable in practice.

Response:

The Department selected the SO_2 BACT emission rate of 0.10 lb/MMBtu for UAF's dual fuel-fired boiler (EU 113) after taking into account multiple pieces of information. UAF's boiler has a contract guaranteed SO_2 emission rate from Babcock & Wilcox (B&W) of 0.19 lb/MMBtu. Dry Sorbent Injection (DSI) is a viable SO_2 control technology on coal-fired boilers with demonstrations and utility testing having shown removals greater than 80% for systems using sodium based sorbents.[50] The Department selected SO_2 emission rate of 0.10 lb/MMBtu using DSI would equate to an approximate 50% control efficiency compared to the B&W guarantee of 0.19 lb/MMBtu.

Additionally, the Department looked at multiple source tests from Eielson Air Force Base in Alaska which has DSI on two of their newer coal-fired boilers (EUs 5a and 6a). These boilers have continually source tested for SO_2 at well below 0.10 lb/MMBtu. This led us to the conclusion that the selected SO_2 emission rate of 0.10 lb/MMBtu is an achievable emission rate that can be applied to the new dual fuel-fired boiler at UAF.

Regarding DSI being economically feasible; the Department notes that UAF calculated the cost effectiveness for DSI at $8,032/ton of SO_2 removed, which the Department considers to be an economically feasible dollar amount for BACT controls. The Department made adjustments to the spreadsheet provided by UAF by updating to the current bank prime interest rate of 5.0%. The updated cost effectiveness value for installing DSI on UAF's dual fuel-fired boiler is $8,010/ton of SO_2 removed using UAF's spreadsheet, which the Department considers economically feasible under BACT.

The Department also calculated the cost effectiveness of installing DSI controls on the dual fuel-fired boiler using the "Dry Sorbent Injection for SO_2 Control Cost Development Methodology, March 2013, prepared by Sargent & Lundy LLC for US EPA" which resulted in a cost effectiveness value of $8,269/ton of SO_2 removed, assuming an average retrofit factor of 1.0, a 0.2 lb/MMBtu SO_2 emission rate, and an 80 percent control efficiency. The Department also considers this value to not cause an adverse economic impact for BACT purposes in a Serious nonattainment area for PM2.5.

The Department notes that, due to the financial indicators provided by UAF and as allowed for under the PM2.5 Implementation Rule, it finds it economically infeasible for UAF to implement retrofit SO_2 controls on the dual fuel-fired boiler at the Fairbanks Campus Power Plant.

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[50] IPM Model-Revisions to Cost and Performance for APC Technologies: https://www.epa.gov/sites/production/files/2015-07/documents/append5_4.pdf

Therefore, the existing NSPS Subpart Db emission limit or 0.20 lb/MMBtu will be retained for the dual fuel-fired boiler. BACT for this unit is maintaining good combustion practices by following the manufacturer's operating and maintenance procedures and combustion of low sulfur coal as a fuel source

Small Diesel-Fired Engines, EU IDs 24, 28, and 29

UAF Comment (22):

Section 5.5 in the proposed BACT Determination for small diesel-fired engines, specifically Step 5(c), states that non-emergency operation of the small emergency diesel-fired engines, EU IDs 24, 28, and 29, is limited to "no more than 100 hours per year for maintenance checks and readiness testing." Please revise this requirement to clarify that the limit is not inconsistent with applicable requirements under 40 CFR 60 Subpart 1111 and 40 CFR 63 Subpart ZZZZ, which allow 100 hours per year of non-emergency operation but does not restrict those non-emergency operations to maintenance checks and readiness testing. Please ensure that Section 7.7.8.6.3 of the proposed SIP document is revised for consistency with the underlying proposed BACT determination.

Response:

The Department revised the BACT determinations for emergency engines in Section 7.7.8.6.3 of the SIP Control Strategies chapter and Section 5.5 of the BACT Determination to clarify that the 100 hours per year limit is not solely for maintenance checks and readiness testing. This allows flexibility and maintains consistency with the applicable requirements under 40 C.F.R. 60 Subpart IIII and 40 C.F.R. 63 Subpart ZZZZ.

Additionally, the Department made changes to the control method column in Table 5-13 of the BACT Determination adding good combustion practices as a control method specified in Section 5.5, and removing federal emission standards which are not identified in Section 5.5.

2. UAF Administrative Services Comments

UAF Comment (23):

Page 39: Last sentence headed with FINDING:

Please delete UAF and replace with AE or Aurora Energy.

Response:

The Department deleted the erroneous reference to UAF on page 39 of the SIP Control Strategies chapter, which is a section containing Aurora Energy's Chena Power Plant.

UAF Comment (24):

Page 74: Second bullet, last paragraph:

> **PM2.5 emissions from EU 113 shall not exceed 0.006 lb/MM BTU over a three-hour averaging period.**

UAF proposes maintaining the emission limit as set in the air quality permit (0.03 lb/MMBTU).

The B&W (boiler manufacturer) contract guarantee is 0.012 lb/MMBTU. The PM2.5 emission limitation in UAF Air Quality permit AQ0316MSS06 Revision 2 condition 41.1a is 0.03 lb/MMBTU, required to meet federally enforceable 40 CFR 63 subpart JJJJJJ requirements. The permit requires UAF to demonstrate compliance by meeting condition 10.1 – operate and maintain the baghouse according to manufacturer's guidelines, and condition 10.2 – install, calibrate, maintain, and operate a triboelectric bag leak detector. UAF will comply with each of these conditions.

ADEC notes in the footnote for this BACT finding that the 0.006 lb/MMBTU emission rate over a three hour averaging period was determined from the "average soot blown run from the worst coal-fired boiler tested at Fort Wainwright during the most recent source test on April 19 through 22, 24, and 25, 2017." It is not reasonable to require UAF to meet the more stringent emission rate based on a source test conducted on a non-UAF operated coal fired boiler with completely different coal combustion technology than the dual-fired continuous fluidized bed boiler EU ID 113. The actual achievable emission limit can be estimated when source testing for total particulate matter (filterable only) is conducted on the boiler during the commissioning process.

Response:

The Department revised the PM2.5 BACT limit for EU 113 to 0.012 lb/MMBtu for consistency with the boiler manufacturer (Babcock and Wilcox) contract guarantee. This contract guarantee is more representative of a BACT limit achievable using a circulating fluidized bed coal-fired boiler, rather than relying on an aging source test on a spreader stoker boiler at a different facility. 0.012 lb/MMBtu was also used to calculate the potential to emit of the source in Minor Permit AQ0316MSS06 and the Application for Operating Permit AQ0316TVP03.

UAF Comment (25):

Page 75 Section 7.7.8.6.2 $PM_{2.5}$ Controls for Fairbanks Campus Power Plant, Mid-Sized Diesel-Fired Boilers:

> **$PM_{2.5}$ emission limits have been proposed in the SIP for EU IDs 3 and 4. $PM_{2.5}$ emissions from EUs 3 and 4 shall not exceed 0.012 lb/MMBtu averaged over a 3-hour period while firing diesel fuel and 0.075 lb/MMBtu while firing natural gas at EU 4.**

UAF proposes that the emissions from EU's 3 and 4 shall not exceed 0.02 lb/MMBtu.

UAF's Air Quality permit AQ0316TVP02 Rev 1 does not currently specify EU emission limits for $PM_{2.5}$ for EU IDs 3 and 4. UAF proposes reporting $PM_{2.5}$ emissions in operating reports calculated by using Indeck's 3/17/2016 emission factors published specifically for Zurn boilers EU 3 and 4. The calculation for EUs 3 and 4 firing diesel provides a $PM_{2.5}$ result of 0.016 lbs/MMBTU.

Response:

The Department did not revise the PM2.5 BACT limits for EUs 3 and 4 because the information provided in the BACT analysis, responses to information requests, and comments didn't provide the 3/17/2016 emission factors from Indeck that were published for Zurn boilers (EUs 3 and 4). As indicated in Footnote 20 of the BACT Determination, the PM2.5 emission factor was calculated using emission factors from AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-6 (PM2.5 size-specific factor from distillate oil, 0.25 lb/1,000 gal) converted to lb/MMBtu using 140 MMBtu/10^3 gallons. Absent additional information the Department finds this information to be the most complete and accurate data used for calculating the BACT limit for EUs 3 and 4.

UAF Comment (26):

Page 79 Section 7.7.8.6.3 SO_2 Controls for Fairbanks Campus Power Plant, Dual Fired Boiler:

> **DEC determined the numerical SO_2 BACT emission limit for the dual fuel-fired boilers at UAF to be 0.10 lb/MMBtu averaged over a 3-hour period with installation of a DSI.**

UAF proposes keeping emission limitation as set in the air quality permit (0.2 lb SO_2/MM BTU on a 30-day rolling average) and placing information at the end of this section stating that DEC finds a retrofit of Pollution control equipment is economically infeasible.

The sulfur emission limit in the UAF Air Quality permit AQ0316MSS06 Revision 2 conditions 13.1 and 28.2 is 0.2 lb SO_2/MM BTU on a 30-day rolling average. B&W has provided a contract guarantee emission rate not to exceed 0.19 lb/MMBTU. UAF cannot be expected to meet the lower limit as determined in the draft SIP while the manufacturer of the boiler contractually guarantees emissions to not exceed a limit almost double the limit proposed in the draft SIP without control equipment.

ADEC also argues the lower limit is justified based on source test data from other coal-fired boilers in Alaska without noting that there are no other boilers in Alaska with the combustion technology of the dual-fired boiler EU ID 113. It is imprudent to assume that differing coal combustion technologies have equal or similar emission rates and characteristics. The CEMS that will measure SO_2 emissions for this new dual-fired boiler will be tested and verified through the RATA (relative accuracy testing) process and then will be used to verify actual achievable emission control.

Paragraph 3, Sentence 2: Please reword this sentence as follows: DEC selected this BACT limit after evaluating existing emission limits in the RBLC database for coal-fired boilers, taking into account previous source test data from coal-fired boilers in Alaska and actual emissions data from other sources employing similar types of controls, using manufacturer data provided in the UAF BACT Analysis January 2017 by Babcock & Wilcox, and in-line with EPA's pollution control fact sheets while keeping in mind that BACT limits must be achievable at all times.

Response:

The Department did not revise the 0.10 lb/MMBtu BACT limit because it finds the limit to be technically and economically feasible and achievable as a practical matter as a BACT Determination (See additional basis in Response to Comment 21). However, the Department did revise the averaging period for the SO_2 emission limit for EU 113 to a 30-day rolling average for consistency with the applicable form of the NSPS Subpart Db Standard and consistent with Air Quality Minor Permit AQ0316MSS06 Rev. 2. The CEMS that will measure SO_2 emissions for this new dual-fired boiler will be tested and verified through the RATA (relative accuracy test audit) process and will be used to verify the BACT limit.

The Department notes that, due to the financial indicators provided by UAF and as allowed for under the PM2.5 Implementation Rule, it does not intend to require installation of DSI for the dual fuel-fired boiler at the Fairbanks Campus Power Plant. Therefore, the existing NSPS Subpart Db emission limit or 0.20 lb/MMBtu will be retained for the dual fuel-fired boiler.

UAF Comment (27):

Page 80, Section 7.7.8.6.3, Mid-Sized Boiler, SO_2 emissions, first bullet:

> **SO_2 Emissions from EUs 3 and 4 shall be controlled by only combusting ULSD when firing diesel fuel.**

UAF proposes operating EUs 3 and 4 with a change in firing fuel from #2 diesel to #1 diesel.

The UAF power plant relies on the two mid-sized boilers EUs 3 and 4 to produce dependable and consistent heat and power for the campus and each will be utilized even when the large dual-fired boiler EU 113 becomes fully operational. This utilization will be to provide heat and power to the campus during periods that EU 113 is shut down for routine maintenance and necessary repairs.

A switch from the current fuel #2 diesel to ULSD would cost UAF an additional $0.30 per gallon with an effective reduction in SO_2 emissions of $16.8/ton SO_2[51]. Switching from #2 to #1 diesel would cost UAF an additional $0.07 per gallon with an effective reduction of $6.00/ton SO_2. Number 1 and #2 diesel are refined locally in North Pole while ULSD must be shipped from South Central Alaska, necessitating potentially unreliable transport through the Alaska

[51] Calculated using AP-42 Table 1.3-1, 5/10 emission factor of 142*S and ADEC's data on Page 21 of the SIP - #2 Diesel is 2566 ppm S and #1 Diesel is 896 ppm S. ULSD is 15 ppm S. Per gallon costs provided by ADEC on the same page of the draft SIP.

Range with the possibility of transportation delays due to natural events such as earthquakes, wildfires, and inclement weather.

The University of Alaska (UA) is now facing a fiscal year 2020 budget cut of $134 million, or 41 percent of the state's funding of $327 million, reducing the university's general fund support to $193 million. UAF simply cannot afford any additional costs across the board and certainly not for the more expensive and less reliably sourced ULSD to combust in mid-sized boilers EUs 3 and 4.

In the second bullet item, please replace NOx with SOx.

<u>Response:</u>

The Department is not revising the BACT limit from requiring a switch to ultra-low sulfur diesel (ULSD) because it was proposed by UAF in the BACT analysis and absent a detailed economic analysis that demonstrates it is not economically feasible, the most effective SO_2 control must be selected per EPA's top down approach. The Department acknowledges that the switch to a cleaner fuel will have an incremental cost increase, but finds that the increase will not have an adverse economic impact for the purposes of reducing emissions in the Serious nonattainment area.

For the BACT Determination, the Department has selected ULSD for combustion in EUs 3 and 4. However, in Section 7.7.8.6 of the SIP Control Strategies Chapter the Department has included a stepped approach for implementing the fuel switch. UAF is required to submit a Title I Permit application by June 9, 2020 that requires the combustion of fuel oil with a sulfur content of 1,000 ppmw starting October 1, 2020 and combustion of ULSD starting October 1, 2023. These requirements will only apply during winter months (October 1 through March 31).

The Department changed the limiting 40 tpy pollutant control in the second bullet from NOx to SO_2 as requested. However, the Department notes that once ULSD is being consumed in EUs 4 and 8, the 40 tpy NOx limit will be the limiting control on these EUs.

<u>UAF Comment (28):</u>

Page 86, DEC BACT DETERMINATION for UAF's Fairbanks Power Plant:

By June 9, 2021, UAF shall limit the sulfur content of coal to 0.2% S by weight.

UAF requests to remove the coal sulfur content limit and continue to provide ADEC with per shipment reports of coal sulfur content in the Facility Operating Reports as is the current practice

ADEC has proposed in the draft SIP that BACT for coal burning facilities in the nonattainment area is a coal-sulfur limit of 0.2% sulfur by weight. Usibelli Coal Mine (UCM) is the only source of commercial coal available to the coal-fired facilities within the Fairbanks North Star Borough fine particulate nonattainment area. Coal shipped from outside the State of Alaska would be cost prohibitive and the transport unreliable.

The mine has limited ability to affect the sulfur content in the coal. There is no coal washing or segregating capability at UCM that could ensure a consistent coal-sulfur concentration. The current practice for providing low-sulfur coal to customers is by identifying sulfur content of the resource through drilling and sampling efforts. UAF is not provided the sulfur content of each shipment until the first week of the month after it was combusted.

Within the millions of tons of coal resources available, there is a significant amount of coal with higher sulfur content than 0.2% (Aurora Energy); in fact, any limit proposed for coal sulfur content is effectively cutting off access to tens of millions of tons of coal resources. It is infeasible for UAF to be limited to a maximum concentration of sulfur in the coal it combusts. UAF does not mine the coal nor has the capability to control the sulfur content of the coal it receives. Anticipating this, UAF designed the new boiler with control of sulfur emissions through limestone injection in the combustion chamber to react with the varying levels of sulfur in the incoming coal and a state of the art baghouse.

ADEC's standard permit condition for coal fired boilers requires the permittee to report sulfur content of each shipment of fuel with the semiannual Facility Operating Report (FOR). UCM currently provides a semi-annual report to all customers that includes sulfur content of each shipment of coal along with the weighted average coal-sulfur content for the six-month period coinciding with the FOR reporting period. UAF will continue to report the sulfur content of each shipment of coal in the Facility Operating Report as required in air quality permit AQ0316TVP02 Rev 1.

Response:

The Department acknowledges that the 0.2 percent sulfur content limit wasn't included as part of the BACT Determination and therefore didn't go through EPA's top-down evaluation process. Instead it was established in the SIP Control Strategies chapter as a method to limit SO_2 emissions in a reasonable way. The Department received multiple comments requesting that this limit be revised to 0.25 percent sulfur by weight. A 0.25 percent sulfur limit meets the Department's need to ensure no backsliding occurs and therefore acquiesced to that request.

The Department is therefore requiring all coal delivered to stationary sources in the Fairbanks nonattainment area to have a gross as received sulfur content of no greater than a 0.25% by weight. This new coal sulfur requirement will need to be incorporated into UAF's air quality permit. The Department used this 0.25% by weight sulfur content to recalculate the cost effectiveness for installing SO_2 controls on the coal-fired boilers at UAF.

Requiring the change in sulfur content to be implemented on an as-delivered-basis will allow the coal already stockpiled at UAF to be utilized.

3. Additional Changes Made by the Department

The Department revised the BACT determinations for emergency engines to clarify that the 100 hours per year limit is not solely for maintenance checks and readiness testing. This allows flexibility and maintains consistency with the applicable requirements under 40 C.F.R. 60 Subpart IIII and 40 C.F.R. 63 Subpart ZZZZ.

The Department updated the table of contents in the BACT Report to include EUs 23, 24, 26, 28, and 29 in Sections 4.5 and 5.5 for PM2.5 and SO_2 for the small diesel-fired engines. Additionally, the Department corrected the rating of the medical/pathological waste incinerator EU 9a in the BACT Report table of contents to 83 lb/hr from 533 lb/hr.

The Department changed the controlling SO_2 limit in Sections 5.4 of the BACT Determination and 7.7.8.6.3 of the SIP Control Strategies chapter from NOx to SO_2 for technical accuracy.