TECHNICAL RESPONSE MEMORANDUM

To: Lisa Vest, Hearing Officer

Through: Valerie Gray vag

From: Renae Held rjh

Date: June 13, 2022

Re: Department's response to the comment received on Delaware's proposed Visibility State Implementation Plan

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You presided over a virtual public hearing on Wednesday, December 29, 2021 beginning at 6:00 PM. The subject of the public hearing was the proposed revisions to Delaware's proposed Visibility State Implementation Plan.

No public comments were received at the hearing. Two written comment letters were submitted after the after the hearing via the Department's Public Hearing Comment Form. The first letter was submitted by the Sierra Club, et al. and the second letter was submitted by the Environmental Protection Agency, Region III[1]. The Department thanks commenters for their comments on this revised proposed State Implementation Plan (SIP).

This memorandum provides a summary of the comments received and the response of the Division of Air Quality (Department) on behalf of the Department.

<u>Comment 1 – Sierra Club et al.</u>

"Rather than conduct a four-factor analysis for the Indian River Generating Station as required by the Clean Air Act (CAA) and the Regional Haze Rule, DNREC impermissibly relied on unenforceable and unverifiable emission reductions from the anticipated retirement Indian River."

<u>Department Response</u>

Delaware disagrees with the commentor's statement that Delaware relied on the anticipated retirement of Indian River Generating Station (Indian River) to forego doing a four-factor analysis. Delaware did not select Indian River for a four-factor analysis because of the low modeled visibility impact. More information about Indian River and the visibility modeling is detailed below.

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[1] Sierra Club et al., dated 1/13/22 and US Environmental Protection Agency, Region III, dated 1/13/22. https://dnrec.alpha.delaware.gov/events/public-hearing-proposed-regional-haze-sip/

Indian River Generating Station

Indian River Generating Station is an electric generating unit (EGU) that consists of two main pieces of electric generating equipment, a boiler and a combustion gas turbine.

The boiler is a coal-fired EGU. The boiler has installed selective catalytic reduction (SCR) for NOx control and SO_2 controls Circulating Dry Scrubber/Flue Gas Desulfurization (CDS/FGD). The combustion gas turbine (turbine) is an EGU that fires distillate fuel oil. The turbine uses a Water Injection system as a NOx control device and uses low sulfur fuel to control SO_2, in accordance with DE Admin. Code 1108 - Sulfur Dioxide Emissions from Fuel Burning Equipment[2].

Regional Haze

Regional haze is defined as visibility impairment that is produced by a multitude of sources and activities which emit fine particles and their precursors, and which are located across a broad geographic area. These emissions are transported over large regions, including national parks, forests, and wilderness areas. The Clean Air Act (CAA) mandates protection of visibility in Class I areas.

In 1977, Congress recognized that our ability to see should be protected, and they adopted provisions in the CAA to improve the visibility "in areas of great scenic importance." These areas have become known as the mandatory Class I Federal Areas (Class I areas) and are located in 35 states and one territory. [40 CFR 81.401-437][3] The Class I designation applies to national parks larger than 6,000 acres and national wilderness areas larger than 5,000 acres that were in existence as of 1977. Delaware does not have a Class I area located within its borders. Therefore, Delaware is not considered a "Class I state".

[2] 7 DE Admin Code 1108 - Sulfur Dioxide Emissions from Fuel Burning Equipment. Section 2.0. https://regulations.delaware.gov/AdminCode/title7/1000/1100/1108.pdf
[3] 40 Code of Federal Regulations (CFR) 81.401-437. Identification of Mandatory Class I Federal Areas Where Visibility is an Important Value. EPA. https://www.govinfo.gov/content/pkg/CFR-2001-title40-vol14/pdf/CFR-2001-title40-vol14-sec81-400.pdf

Regional Haze Rule - Four Factor Analyses
40 Code of Federal Regulations (CFR) Section 51.308 (f)(2)(i) [4] of the Regional Haze Rule (RHR) requires all states to consider the following four factors to determine which additional emission control measures are needed to make reasonable progress in improving visibility: 1) costs of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of any existing source subject to such requirements. These are known as the four statutory factors.

40 CFR Section 51.308 (f)(2)(i) states:

> *"(2)* ***Long-term strategy for regional haze.*** *Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. ... In establishing its long-term strategy for regional haze, the State must meet the following requirements:*
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> *(i) The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress."*

[4] 40 CFR Section 51.308. Regional haze program requirements. EPA. 7-1-21 Edition. Page 315.
https://www.govinfo.gov/content/pkg/CFR-2021-title40-vol2/pdf/CFR-2021-title40-vol2-sec51-308.pdf

Delaware is not required to perform a perform four-factor analyses on all of its sources. In the Environmental Protection Agency's (EPA) 2019 Regional Haze Guidance [5], EPA gives states the flexibility to identify sources for which it will perform a four-factor analysis.

The 2019 Regional Haze Guidance states:

> *"A key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures. The guidance that an analysis of control measures is not required for every source in each implementation period is based on CAA section 169A(b)(2), which requires each SIP to contain emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress, but…does not provide direction regarding the particular sources or source categories to which such emission limits, etc., must apply. Selecting a set of sources for analysis of control measures in each implementation period is also consistent with the Regional Haze Rule, which sets up an iterative planning process and anticipates that a state may not need to analyze control measures for all its sources in a given SIP revision."*

CAA section 169A(b)(2)[6] states:

> *"(b) Regulations. Regulations under subsection (a)(4) of this section shall—…(2) require each applicable implementation plan for a State in which any area listed by the Administrator under subsection (a)(2) of this section is located (or for a State the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area) to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal specified in subsection (a) of this section…"*

[5] "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period." EPA. August 20, 2019. Page 9. https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[6] 42 U.S.C. §7491. Visibility protection for Federal class I areas. https://www.govinfo.gov/content/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partC-subpartii-sec7491.htm

To aid states in their efforts to develop the technical basis for the state's implementation plans, multi-state regional planning organizations (RPOs) have been established. These organizations provide a forum for state air control administrators to develop regional strategies to address regional haze and to coordinate with other regions. Delaware is a member of the Mid-Atlantic /Northeast Visibility Union (MANE-VU) and has used MANE-VU modeling, inventory analyses, emission reduction strategies, etc. to draft its SIP.

Relying on regional analyses is specifically allowed by EPA's RHR [40 CFR 51.308(f)(2)(iii)][7]. Delaware worked with other MANE-VU states to choose which sources would be selected for four-factor analyses. The process for choosing sources for four-factor analyses is summarized below (Section 9.0 of Delaware's RH SIP.

MANE-VU Source Selection for Four-Factor Analyses

Delaware used MANE-VU modeling results to determine which facilities it would perform four-factor analyses on for the second regional haze rule implementation period (second implementation period), as detailed below.

In order to determine the key source regions and source types affecting visibility impairment at each Class I area, a contribution assessment was prepared by NESCAUM for MANE-VU. Major contributors were identified by ranking emissions sources, comparing Q/d (emission impact over distance), and modeling visibility impacts as detailed in "Assessment of Reasonable Progress for Regional haze in MANE-VU Class I Areas." July 2007[8] (Section 9.3 of Delaware's RH SIP). Source apportionment and other analyses documented in MANE-VU's contribution assessment showed that several source categories have impacts on visibility at MANE-VU Class I areas.

[7] 40 CFR 51.308(f)(2)(iii) states: "The State must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects. The State may meet this requirement by relying on technical analyses developed by a regional planning process and approved by all State participants…."

[8] "Assessment of Reasonable Progress for Regional haze in MANE-VU Class I Areas." MACTEC Federal Programs Inc. July 9, 2007. https://s3.amazonaws.com/marama.org/wp-content/uploads/2019/11/13093755/MANE-VU-Assessment-Progress-Report-2007.pdf

Based on available information about emissions and potential impacts, MANE-VU selected the following source categories for detailed analysis of the four factors[9] during the 1st implementation period, as detailed in *"Assessment of Reasonable Progress for Regional haze in MANE-VU Class I Areas." July 2007*:

- Coal and oil-fired EGUs;
- Point and area source ICI boilers;
- Cement kilns;
- Lime kilns;
- The use of heating oil; and
- Residential wood combustion and open burning.

This analysis was updated in 2016. The updated analyses are described in detail in "*2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*" [10], Appendix 8-4 of the RH SIP. Using the 2007 and 2016 analyses, the modeling effort for the 2nd implementation period focused on EGUs and large industrial and institutional sources in the eastern and central United States[11] (Section 9.3 of Delaware's RH SIP).

This information was used to determine which individual facilities in MANE-VU may have the highest impact on visibility impairment and where to focus emission reduction strategies, such as installation or upgrade of emission controls.

MANE-VU CALPUFF Modeling

For the second implementation period RH SIPs, air pollution transport modeling was performed with the California Puff Model (CALPUFF) dispersion model[12], which is used to simulate sulfate and nitrate formation and transport in MANE-VU and nearby regions. As stated above, the modeling effort for the 2nd implementation period focused on EGUs and large industrial and institutional sources in the eastern and central United States.

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[9] Ibid. 8.

[10] "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas." Mid Atlantic Regional Air Association (MARAMA). January 31, 2016. https://s3.amazonaws.com/marama.org/wp-content/uploads/2019/09/13095234/FINAL_Updates_to_4Factor_Reasonable_Progress_Report_2016_01_31.pdf (Appendix 8-4 of Delaware's RH SIP).

[11] "MANE-VU Regional Haze Consultation Report." MANE-VU. July 2018. (Appendix 8-12 of Delaware's RH SIP). https://otcair.org/manevu/Upload/Publication/Correspondence/MANE-VU_RH_ConsultationReport_Appendices_ThankYouLetters_08302018.pdf

[12] "2016 MANE-VU Source Contribution Modeling Report – CALPUFF Modeling of Large Electrical Generating Units and Industrial Sources." MANE-VU. April 2017. (Appendix 8-5 of Delaware's RH SIP). https://otcair.org/manevu/Upload/Publication/Reports/MANE-VU%20CALPUFF%20Modeling%20Report%20Draft%2004-4-2017.pdf

For the 2016 modeling effort, the MANE-VU Technical Support Committee (TSC) provided a preliminary list of EGU sources. This list was based on an enhanced emissions over distance (Q/d) analysis considering recent SO_2 emissions in the eastern United States and an analysis that adjusted previous 2002 MANE-VU CALPUFF modeling by applying a ratio of 2011 to 2002 SO_2 emissions.[13]

Indian River was one of two Delaware sources selected for CALPUFF modeling[14]. The results of the CALPUFF modeling for Delaware are shown in Table 1 below.

Table 1 - CALPUFF Modeling Results for Delaware

Class I Area	Facility	Max Extinction Value (Mm-1) 2011	Max Extinction Value (Mm-1) 2015
Acadia	Indian River	1.0	0.3
Acadia	Edge Moor	0.3	NA
Brigantine	Indian River	1.2	0.6
Brigantine	Edge Moor	0.2	NA
Great Gulf	Indian River	1.0	0.1
Great Gulf	Edge Moor	0.1	NA
Lyebrook	Indian River	1.0	0.2
Lyebrook	Edge Moor	0.1	NA
Moosehorn	Indian River	1.3	0.3
Moosehorn	Edge Moor	0.3	NA
Campobello	Indian River	1.2	0.1
Campobello	Edge Moor	0.3	NA
Presidential Range	Indian River	1.1	0.3
Presidential Range	Edge Moor	0.1	NA
Dolly Sods	Indian River	1.0	0.4
Dolly Sods	Edge Moor	0.1	NA
Otter Creek	Indian River	0.8	0.4
Otter Creek	Edge Moor	0.1	NA
James River Face	Indian River	1.1	0.7
James River Face	Edge Moor	0.4	NA
Shenandoah	Indian River	1.7	0.5
Shenandoah	Edge Moor	0.2	NA

[13] Ibid. 11.
[14] In addition to Indian River Generating Station, Edgemoor Energy Center (Calpine) was also selected for modeling (see Table 2 of this memo).

3.0 Mm^{-1} Visibility Impairment Threshold for Selection of Four-factor Analyses

MANE-VU used the CALPUFF modeling results to select sources for four-factor analyses. The modeling threshold was 3.0 Mm-1 or greater visibility impacts at any MANE-VU Class I area.

The sources selected for four-factor analyses were identified in the MANE-VU document *"Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress for the Second Regional Haze Implementation Period (2018-2028)."* This document lists a number of regional emission reduction strategies that are cooperatively developed by states that are members of MANE-VU[15], called "Asks).

"Ask" #2[16] required emission sources modeled by MANE-VU that had the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution analyses[17], were to perform a four-factor analysis for reasonable installation or upgrade to emission controls.

MANE-VU Class I states chose 3.0 Mm^{-1} as an appropriate visibility impairment threshold because the sources at or above this threshold contributed the largest percentage of visibility impairing pollutants that impact MANE-VU Class I areas.

Delaware used the 3.0 Mm^{-1} threshold, which was agreed to by all MANE-VU states[18], including the Class I states, to select sources for the performance of four-factor analyses. The 3.0 Mm^{-1} threshold was determined after extensive consultation between the MANE-VU states.[19]

[15] "Statement of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress for the Second Regional Haze Implementation Period (2018-2028)." MANE-VU. August 25, 2017. (Appendix 9-1 of Delaware's RH SIP). https://otcair.org/manevu/Upload/Publication/Formal%20Actions/MANE-VU%20Intra-Regional%20Ask%20Final%208-25-2017.pdf

[16] MANE-VU "Ask #2": "Emission sources modeled by MANE-VU that have the potential for 3.0 Mm-1 or greater visibility impacts at any MANE-VU Class I area…perform a four-factor analysis for reasonable installation or upgrade to emission controls".

[17] Ibid. 12.

[18] Ibid. 15.

[19] Ibid. 11.

EPA and Federal Land Managers (FLMs) were also included in the consultation process and had the opportunity to review the MANE-VU Asks. In accordance with the MANE-VU "*Inter-RPO State/Tribal and FLM Consultation Framework*"[20], EPA and FLMs were given 30-day period days to review the final draft of the MANE-VU Asks, before consultation meetings.

Class I States must establish reasonable progress goals (RPGs) (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the applicable implementation period as a result of those enforceable emissions limitations, compliance schedules, and other measures. Delaware is not required to calculate RPGs, since it has no Class I areas within its borders.

Each Class I state calculates an individual 2028 RPG for each of the Class I areas in their state. MANE-VU modeled visibility in the Class I areas to determine the impact of implementation of the Asks.[21] The Class I states used the modeling results to develop each individual Class I state's 2028 RPGs.

The following bullets highlight additional information regarding the selection 3.0 Mm^{-1} as the threshold:

- A "Top-10 impacting units at each Class I area" type of approach was considered in the early stages of developing the analysis. However, it was felt that this type of approach would have an unfair balance of requiring more stringent criteria for some facilities near clearer Class I areas than would be applied to those affecting hazier Class I areas. The MANE-VU states agreed to identify a uniform threshold that approximates the average of the top 10 most potentially contributing units. Therefore, it was felt that a threshold based on an absolute Mm^{-1} magnitude would be more appropriate.

- Preliminary analysis showed that a 3.0 Mm^{-1} threshold would approximate the top 7 to 26 impacting emissions units, depending on Class I area.[22]

[20] "Inter-RPO State/Tribal and FLM Consultation Framework." MANE-VU. May 10, 2006. https://otcair.org/manevu/Upload/Publication/Correspondence/Final%20consultation%20framework%20as%20approved%20by%20MV_Board_060510.pdf
[21] "Ozone Transport Commission/Mid-Atlantic Northeastern Visibility Union 2011 Based Modeling Platform Support Document – October 2018 Update" MANE-VU. October 18, 2018. https://otcair.org/manevu/Upload/Publication/Reports/OTC%20MANE-VU%202011%20Based%20Modeling%20Platform%20Support%20Document%20October%202018%20-%20Final.pdf
[22] Ibid.11.

- A higher (i.e. less restrictive) threshold of 10.0 Mm^{-1} and lower (i.e. more restrictive) thresholds of 1.0 and 2.0 Mm^{-1} were considered. However, preliminary analysis showed that a cutoff of 5.0 or 10.0 Mm^{-1} would only have the potential to bring in a very small number of units. Lower thresholds of 2.0 and 1.0 Mm^{-1} roughly doubled and tripled the number of units identified for 3.0 Mm^{-1} with diminishing potential visibility benefit per analysis required[23].

- This approach limited the "Ask" to those units with the greatest potential for visibility improvements per analysis conducted.

Results of Threshold Modeling for Delaware Emission Sources

Delaware did not have any emission sources that had the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area. Therefore, Delaware did not select Indian River for a four-factor analysis. Low visibility impacts were used as a reason to exclude Indian River from a four-factor analysis, not the anticipated shutdown of Indian River (expected to be completed at or before December 31, 2026[24]), as the commentor contends.

The highest MANE-VU modeled visibility impact value for Indian River was 1.7 Mm^{-1} in 2011 for Shenandoah National Park (see **Table 1, Page 7** of this memo), which is well below the 3.0 Mm^{-1} threshold for control analysis set in MANE-VUs "Ask #2". Therefore, Indian River was not selected for a four-factor analysis.

However, Delaware did conduct a four-factor analysis on the turbine at Indian River, as detailed below. As presented in Section 10.5, page 114 of Delaware RH SIP, Delaware discusses the four-factor analysis for the Indian River turbine.

MANE-VU Ask #5 – Four-factor Analysis Selection

MANE-VU "Ask" # 5[25] was developed to control NOx emissions from combustion turbines that have the potential to operate on high electric demand days (HEDD). HEDD are days when higher than usual electrical demands bring additional combustion turbines online, many of which are infrequently operated and may have significantly higher emission rates than other EGUs.

[23] Ibid.11.
[24] PJM deactivation request for Indian River Generating Station. https://www.pjm.com/planning/services-requests/gen-deactivations.aspx
[25] "Asks" are regional emission reduction strategies that are cooperatively developed by states that are members of MANE-VU.

MANE-VU "Ask" #5[26] states:

> *"Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days (HEDD) by:*
>
> *a. Striving to meet NOx emissions standard of no greater than 25 ppm at 15% O2 for natural gas and 42 ppm at 15% O2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O2 for natural gas and 96 ppm at 15% O2 for fuel oil, or*
> *b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or*
> *c. Obtaining equivalent alternative emission reductions on HEDD.*
>
> *HEDD are days when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet. Peaking combustion turbine is defined for the purposes of this "Ask" as a turbine capable of generating 15 MW or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016;"*

The turbine at Indian River meets the definition of a HEDD turbine. The combustion gas turbine (turbine) is an EGU that fires distillate fuel oil. The turbine uses a Water Injection system as a NOx control device.

Use of controls and permit limits can be influenced by two variables, fuel type and season.

- Fuel type – Controls are often designed to be used with a specific fuel type (Coal, Fuel Oil, or Natural Gas). Therefore, controls might only be used at a facility when firing a specific type of fuel.

[26] Ibid. 15.

- Ozone Season – 7 **DE Admin. Code** 1148[27], *Control of Stationary Combustion Turbine Electric Generating Units*. Regulation 1148 requires subject stationary combustion turbine EGUs with a base-load nameplate capacity of one MW or greater to limit NOx emissions during the ozone season (May – September): 42 ppmv for natural gas and 88 ppmv for fuel oil. Therefore, controls may only be used at a facility during the ozone season, to meet the requirements of Regulation 1148. In addition, permit limits may vary depending on the season.

The current NOx permit limit for the turbine is 88 ppm, only from May 1-September 30 (ozone season). Therefore, the turbine did not meet the year-round NOx limit set in the MANE-VU "Ask" #5 of 96 ppm. As a result, Delaware selected the turbine for a four-factor analysis.

Indian River Gas Combustion Gas Turbine, Four-Factor Analysis

Delaware conducted a four-factor analysis[28] on turbine, to determine the feasibility of new or upgraded NOx controls, in specific response to the "Ask # 5", (Section 10.5 of the RH SIP). Indian River is owned and operated by NRG Energy (NRG). NRG supplied information regarding the economic and technical feasibility of increased NOx controls is detailed below (see Appendix 10-1 of Delaware's RH SIP).

As detailed below, Delaware used the four statutory factors to evaluate the two technologically feasible NOx controls able to be used on the turbine: water injection (WI)[29] and natural gas conversion.

[27] 7 **DE Admin. Code** 1148, "Control of Stationary Combustion Turbine Electric Generating Units." https://regulations.delaware.gov/AdminCode/title7/1000/1100/1148.pdf
[28] The four statutory factors to determine which additional emission control measures are needed to make reasonable progress in improving visibility are: 1) costs of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts of compliance, and 4) remaining useful life of any existing source subject to such requirements.
[29] A water injection system injects demineralized water into the turbine combustor through the fuel nozzles to regulate the combustor flame temperature and lower NOx emissions.

Water Injection (existing control)

- The WI system at Indian River is not weatherized to operate in cold temperatures. Therefore, the system could be damaged if operated in cold weather as is it currently designed. NRG evaluated the cost of updating the system for cold weather operations. The capital costs of converting the system for winter operation would require constructing a stand alone building for WI system, new water tanks, transformers and electrical system modifications, heat tracing, heating systems, piping, foundation work, and control system modifications.
- Cost of Compliance - NRG estimated the total capital cost to be $205,200 and an annual cost of $192,000/ton of NOx removed. Costs estimates were based on estimates for a similar project in another state.
- Time Necessary for Compliance – Construction of a new building and other necessary components would take approximately 1 year.
- Non-air Environmental Impacts of Compliance – Potential additional emissions for additional power generation to power WI and heating equipment. Increased water use.
- Remaining Useful Life of Source – Shutdown expected by 2027. In June of 2021, NRG Energy announced that it was planning to close Indian River in May of 2022. The planned closure was contingent on a grid reliability study from the regional power grid operator PJM. Based on their study, PJM determined the plant is needed for reliability. In order for the transmission system to carry the weight of the plant closure, PJM would need to update its services. Those upgrades are expected to be completed at or before December 31, 2026. Once the upgrades are complete, Indian River would be able to shut down.

The Department also requested that NRG evaluate the economic feasibility of operating controls in the two months adjacent to the ozone season, April and October, as the likelihood of encountering freezing temperatures is lower. In its analysis, NRG stated that because the demineralized water is required and the water source is rented, adding operations in April and October would result in an added expense in the range of $5,000 per month, or $10,000 for two months. These estimates are based off of previous rental costs at the facility.

The probability of the turbine operating during the months of April and October is extremely low. Over the past 5 years, the turbine has only operated a total of 6.22 hours in the months of April and October. In addition, the facility does not anticipate that the turbine would be called to be run for system reliability in these months and they would not schedule a required stack test at this time. Therefore, Delaware believes that expanding WI operations to include April or October is not economically feasible.

Natural Gas Conversion (new control)

Indian River does not have access to a natural gas supply pipelines or storage on site and has not had access to pipelines/storage in the past. NRG has considered replacement of the turbine, if associated with a conversion to natural gas. The inability of third-party companies to bring a natural gas supply to the area has prohibited this option. As a result, the facility does not have cost information available for this option. Therefore, it is not economically or technically feasible to convert to natural gas for the turbine.

NRG Energy, operator of Indian River, estimated the total capital cost to be $205,200 and an annual cost of $192,000/ton of NOx removed. Costs estimates were based on estimates for a similar project in another state. Therefore, Delaware determined that conversion to natural gas is not economically feasible.

The turbine is expected to shutdown on or before December 31, 2026 [30]. Since the turbine would potentially be operating through 2026, well into the 2nd implementation period (2018-2028); Delaware determined that "remaining useful life" could not be used as a criteria to eliminate the need for new or upgraded controls for the turbine.

Conclusion

Delaware disagrees with the commentor's statement that Delaware relied on the anticipated retirement of Indian River to forego doing a four-factor analysis. Because of the low modeled visibility impact of the facility as a whole, Delaware chose not to perform a four-factor analysis on Indian River. Delaware believes that a four-factor analysis of Indian River was not necessary to ensure reasonable further progress during the 2nd planning period, because the modeled visibility impact was low.

[30] Ibid. 24.

However, Delaware did complete a four-factor analysis on the turbine at the facility, in response to MANE-VU "Ask #5". The "cost of compliance" was the reason Delaware did not recommend additional controls be added to or upgraded for Turbine.

Comment 2 – Sierra Club et al.

"DNREC incorporated the updated Mid-Atlantic Northeast Visibility Union (MANE-VU) asks to comply with the reasonable progress requirements of 40 C.F.R. § 51.308(f)(2)(ii) through (iv). However, the current requirements applicable to Indian River Unit 4 [the boiler] do not comply with these asks. In particular, the first MANE-VU ask requires in relevant part that for '[Electrical Generating Units (EGUs)] with a nameplate capacity larger than or equal to 25 megawatts (MW) with already installed [nitrogen oxides (NOx)] and/or [sulfur dioxide (SO2)] controls" such as Unit 4, DNREC must "ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions.'

DNREC claims that the state "has met this portion of 'Ask #1'" because the state "is in the process of updating all applicable permits that do not currently include language regarding the effective use of controls for applicable facilities (optimization of controls and/or operation in accordance with the manufacturer's recommendations)" and "many of the applicable units currently have short term emission limits that help ensure the effective use of controls." This is inadequate. Although Indian River Unit 4 installed updated pollution controls for SO_2 and NOx, emission data since the installation of those controls in 2011 evidences a steady decline in performance. Specifically, as shown in Table 1 [below], between 2012 and 2021, the emission rate for SO_2 nearly tripled and the emission rate for NOx increased by almost fifty percent."

Table 1: Annual Emissions Data for Indian River Unit 4

Year	SO2 (tons)	SO2 rate (lb/MMBtu)	NOx (tons)	NOx rate (lb/MMBtu)
2012	692.0	0.117	399.9	0.069
2013	958.8	0.135	531.7	0.077
2014	752.8	0.176	330.0	0.081
2015	649.7	0.212	255.5	0.089
2016	462.1	0.180	204.7	0.082
2017	474.5	0.244	162.7	0.087
2018	441.3	0.289	132.1	0.091
2019	246.2	0.280	73.7	0.086
2020	275.9	0.346	75.4	0.099
2021*	554.7*	0.308*	168.0*	0.102*

* = Data for Q1 to Q3 only.
Data from EPA's Air Markets Program Database (pulled 12/19/2021)

Department Response

Delaware disagrees with the commentor's statement that the increase in the annual emissions rate from the above from EPA's Clean Air Markets Division (CAMD) data indicate that the performance of Unit 4, a boiler is declining.

Under the Clean Air Act, most fossil fuel-fired power plants must continuously monitor and report their emissions of nitrogen oxides (NOX), and sulfur dioxide (SO2) to EPA[31]. Emissions are monitored by continuous emission monitoring systems (CEMS) or equivalent that power plants install and maintain. Indian River is required to submit quarterly reports to show compliance with permitted emission limits. No NO_x or SO_2 emission rate violations for the boiler have been discovered through the inspection process for the past 3 inspections of Indian River (see Section "Quarterly Reports/Inspection/ Maintenance" below for more details.)

In addition, Delaware does not believe that average annual emission rate data from CAMD that the Commentor references, is appropriate to be used to determine the boiler's compliance with the permit. CAMD collects continuously monitored NO_X and SO_2, emissions data from EGUs to check compliance with a variety of federal air quality programs. The emissions data reporting to CAMD was primarily developed to show compliance with "emission trading programs", it is not intended to be used to determine compliance with permitted emissions limits for a specific EGU.

CAMD data has two disadvantages that make it inappropriate to use to determine compliance with permitted emission rate limits:

1) Base load vs. peaking units. Transition of the boiler from a "base load unit" to a "peaking unit" has resulted in more startups/shutdowns. Because the controls for the boiler can't be run at the low temperatures associated with startup/shutdowns, emissions are higher during startup/shutdown. Therefore, peaking units can have average higher emission rates compared to base load units, as summarized below ("Startup-shutdown Emissions"). CAMD annual emission rate averages do not differentiate between steady state operation and startup/shutdown events, all the CEMS data is combined.

[31] 40 CFR Part 75 - Continuous Emission Monitoring. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-75

2) Data Substitution. Data substitution can result in higher reported emission rates, as summarized below ("CAMD Data Substitution").

However, Indian River is required to submit quarterly reports to show compliance with permitted emission limits and ensure effective performance of control devices and is required to perform relative accuracy test audits (RATA) tests on its CEMS, to ensure that the devise is properly calibrated. In addition, Indian River is required by their permit to perform regular maintenance on control devices for the boiler, in order to maximize emission reductions. Delaware believes that these reports/tests are a more accurate method of determining compliance with permitted emission limits than CAMD data, which was primarily developed for use in trading programs, as detailed below.

Startup-shutdown emissions

Indian River Unit 4 is a coal-fired EGU. The unit has installed NOx controls, selective catalytic reduction (SCR), and SO_2 controls circulating dry scrubber flue gas desulfurization (CDS-FGD). These controls became operational in December 2011.

Neither the SCR nor the CDS can operate during startup or shutdown because of temperature limitations. The SCR requires 600°F before ammonia can be introduced to the gas stream and the CDS requires about 225°F before water injection, typically in the 210 gross megawatt (MW) range. To mitigate the effect of a shutdown, the facility leaves the control devices on as long as it is possible, given the same temperature constraints on the control devices.

In the past the boiler ran as a "base load unit" and had few startups/shutdowns. More recently, the boiler has run as a "peaking unit". Peaking units generally run only when there is a high demand for electricity, known as "peak demand". Because the controls for the boiler can't be run at the low temperatures associated with startup/shutdowns, emissions are higher during startup/shutdown. Therefore, peaking units generally have higher annual emissions than base load units.

Permit limits for the boiler take into consideration the inlet temperature requirements for each control device. Therefore, there are separate startup emission limits in the permit:

Steady state operation:

- SO_2 emissions rate limitation of 0.20 lb/MMBTU (rolling 24-hour average)
- NOx emissions rate limitation of 0.10 lb/MMBTU (rolling 24-hour average)

Startup/shutdown:

- SO_2 emissions rate limitation of 4.5 lb/mmBtu per hour during startup and shutdown
- NOx emissions rate limitation of 0.5 lb/mmBtu for 3 consecutive hours during startup and shutdown

CAMD Data Substitution

While the CEMS measure continuously, there may be operating hours when a CEMS does not provide valid data due critical system malfunctions, missed or failed quality assurance tests, routine maintenance, or other problems. When data is missing or invalid, EPA's regulation[32] specifies how to estimate and substitute the data. The longer or more frequent the missing or invalid data, the more conservative (i.e., likely to overestimate emissions) the substitute data algorithm becomes[33].

When the duration and/or frequency of missing or invalid data is long, the power plant may have to report maximum potential concentration or flow rate, regardless of operating level. This approach is likely to overestimate emissions.

Given the potential conservative effect of substitute data on annual emission data, which can erroneously increase annual emission rates; it is Delaware's position that CAMD data is not an appropriate method to evaluate performance of a unit.

[32] 40 CFR part 75 Subpart D, §§75.30-37. Missing Data Substitution Procedures. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-75#subpart-D

[33] "EPA's CAMD Power Sector User Guide" (page 7): "If a monitoring system is unavailable or not providing valid data, an EGU must report substitute data to account for emissions until valid data are available. Substitute data is calculated based on the methodologies described in Table 4A of 40 CFR 75.57 and become increasingly conservative (i.e., likely overestimate emissions) based on the length and frequency of the missing data period and are intended to ensure that underreporting does not occur." https://www.epa.gov/sites/default/files/2020-02/documents/camds_power_sector_emissions_data_user_guide.pdf

Quarterly Reports/Inspections/Maintenance

Indian River is required to submit quarterly reports to show compliance with permitted emission limits and ensure effective performance of control devices. Indian River is also required to perform relative accuracy test audits (RATA) tests on its CEMS, to ensure that the devise is properly calibrated. These reports are reviewed by Division of Air Quality (AQ) staff to identify and potential violations. In addition, Indian River is required by their permit to perform regular maintenance on the boiler and its control devices, in order to maximize emission reductions.

Indian River is also inspected every two years by AQ staff to determine compliance with the Title V permit. No NOx or SO_2 emission rate violations for the boiler have been discovered through the inspection process for the past 3 inspections (2016-2020).

Conclusion

Delaware believes that proper maintenance of the boiler/control units and inspection of reports/data and RATA testing submitted by Indian River, has shown continued compliance with the permitted emission limit rates. Delaware does not believe that CAMD data is an accurate indicator of boiler performance for determining compliance with the permitted emission rates.

Comment 3 – Sierra Club et al.

"DNREC Must Include an Enforceable Retirement Date for Indian River Unit 4 [the boiler] and Must Strengthen the Emission Limits Applicable to the Facility Prior to that Date."

Department Response

Since an exact expected shutdown date for the boiler has not yet been determined by the facility[34], Delaware is unable to include an enforceable retirement date in its SIP.

[34] PJM deactivation request for Indian River Generating Station. https://www.pjm.com/planning/services-requests/gen-deactivations.aspx

Delaware used MANE-VU modeling results to determine which facilities it would perform four-factor analyses on for the second regional haze rule implementation period (second implementation period), see response to **Comment 1**, **Page** 5 above for a detailed description. As shown in **Table 1** of this technical response memo, the highest MANE-VU modeled visibility impact value for Indian River was 1.7 Mm-1 in 2011 for Shenandoah National Park, which is well below the 3.0 Mm-1 threshold for control analysis set in MANE-VUs "Ask #2". Therefore, as Indian River was determined to have a low impact on visibility impairment, Delaware chose not to perform a four-factor analysis on the facility.

In addition, because of the low visibility impact of the Indian River facility, Delaware believes that it is not necessary to perform a four-factor analysis of the facility to make reasonable progress during the 2nd implementation period.

Conclusion

Delaware does not believe that it must include an enforceable retirement date for the boiler in its RH SIP, as the expected retirement of Indian River had not yet taken place. In addition, because of the low modeled visibility impact of the as Indian River was determined to have a low impact on visibility impairment, Delaware does not believe that it is necessary to strengthen the emission limits for Unit 4 in order to make further reasonable progress.

<u>Comment 4 - Sierra Club et al.</u>

"…DNREC's haze plan must include a thorough review of the Refinery, including a four-factor analysis under the reasonable progress criteria…Instead, the Draft Haze Plan (at 91-93) simply recites a list of air pollution standards to which the Refinery is already subject. DNREC relies, in part, on emission limits included in a consent decree that is more than ten years old (at 91) and that reflects neither the contemporary reasonable progress standard nor improvements in emission controls since the decree was concluded….

Regardless, the list of limits in the Draft Haze Plan, whether or not currently applicable and enforceable, does not and cannot substitute for the requirement to include a source in the four-factor analysis under the Clean Air Act and the Regional Haze Rule. 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i). It is unlawful for the DNREC to fail to include a four-factor analysis that includes the Refinery in the Draft Haze Plan."

Department Response

Delaware disagrees with the commentors statement that Delaware must perform a four-factor analysis on the Refinery. Delaware chose not to perform a four-factor analysis on the Refinery because its impact on visibility impairment was low. In addition, Delaware believes that the Refinery is currently well controlled through existing state regulations and several Consent Decrees. More information about the Refinery, selection of sources for four-factor analyses, and Refinery controls are detailed below.

Delaware City Refinery

The Refinery is located on 5,050-acres approximately one-mile northwest of Delaware City, Delaware. The refining operations occupy about 1,000-acres. The facility commenced operation in 1956. The facility processed a variety of crude oils and currently produces about 180,000 barrels of petroleum product a day. Production has included diesel, gasoline, jet, fuel oil, aromatics, and methanol and propane fuels.

As a result of its configuration and petroleum refinery processing units, Delaware City has the capability to process a diverse heavy slate of crudes with a high concentration of high sulfur crudes making it one of the largest and most complex refineries on the East Coast. It possesses an extensive distribution network of pipelines, barges and tankers, truck and rail for the distribution of its refined products.

Selection of sources for a four-factor analysis

EPA does not require a four-factor analysis on all sources within a state. In EPA's 2019 Regional Haze Guidance[35], it gives states the flexibility to identify sources for which it will perform a four-factor analysis (see **Comment 1, Page 2** of this memo). Delaware used MANE-VU modeling to determine which sources it would perform four-factor analyses for. Delaware chose not to perform a four-factor analysis on the Delaware City Refinery (Refinery), as its impact on visibility impairment was low, as summarized below ("MANE-VU Modeling").

[35] Ibid. 5.

In addition, Delaware believes that the Refinery is currently well controlled through existing state regulations and several Consent Decrees, as detailed below ("State and Federal Regulations" and "Consent Decrees"). Therefore, a four-factor analysis on the facility is not needed to make reasonable progress during the 2nd implementation period. Delaware will reevaluate sources in the 3rd implementation 2028-2038 period, to determine which sources should complete a four-factor analysis.

MANE-VU Modeling

MANE-VU CALPUFF modeling was used to determine which individual facilities in MANE-VU may have the highest impact on visibility impairment and where to focus emission reduction strategies, such as installation or upgrade of emission controls.

Through the RH SIP planning process, MANE-VU states decided to focus on source categories that had larger numbers of sources and overall emissions; specifically EGUs, Industrial Commercial and Institutional (ICI) boilers, and fuel oil combustion.

In MANE-VU's screening process, the Refinery was evaluated, but ultimately was not one of the facilities that was chosen for CALPUFF modeling, as its impact on visibility impairment was low. See **Comment 1, Page 6** of this memo for a discussion of the MANE-VU screening process.
For Delaware, two EGUs, Indian River Generating Station and Edge Moor Energy Center, were chosen for CALPUFF Modeling. A threshold of 3.0 Mm^{-1} Maximum Extinction Value was used to select facilities for four-factor analyses (MANE-VU "Ask #2"). Maximum Extinction Values were based on the CALPUFF modeling results. See **Comment 1, Page 7,** of this memo for a discussion of the selection of the 3.0 Mm^{-1} modeling threshold level.

Neither Indian River (Indian River) nor Edge Moor were selected for four-factor analyses, as their modeled Maximum Extinction Value (Mm^{-1}) were well below the 3.0 Mm^{-1} threshold. The results of the CALPUFF modeling for Indian River and Edge Moor are shown in **Comment 1, Table 1**.

Consent Decrees

A federal consent decree (C. A. No. H-01-0978)[36] required control of SO_2, and NOx Emissions at the Refinery. The last changes to consent decree emission limits were in 2011. Limits set in the Consent Decree are summarized below:

Boilers and Heaters

- The Refinery was required to install NOx controls on at least 30 percent of the heater and boiler capacity located at the facility. Heaters and boilers which the Companies shut down, or for which the Companies obtained an emission limit of 0.040 pounds (lbs) of NOx per million British Thermal Units (MMBTU) or lower were considered as having NOx controls installed.
- The Refinery also accepted New Source Performance Standards (NSPS) Subpart J applicability for heaters and boilers and reduced or eliminated fuel oil firing in their heaters and boilers in an effort to reduce SO_2 emissions.

Fluid Catalytic Cracking Unit (FCCU) and Fluid Coking Unit (FCU)

- The FCCU converts refinery intermediates and purchased feedstock into high octane gasoline and other intermediate products by a catalytic cracking reaction.
- The FCU allows the refinery to process low cost, high sulfur crude oil to produce high value products such as gasoline.

SO_2

- The Refinery consent decree required SO_2 emission reductions from the Refinery's Fluid Catalytic Cracking Unit (FCCU) and Fluid Coking Unit (FCU). For the FCCU/FCU, the Consent Decree control requirements required the installation of wet gas scrubbers for SO_2 control.
- FCCU – the permit for the Refinery limits SO_2 to: 25 parts per million by volume, dry (ppmvd) @ 0% Oxygen (O2) on a 365 day rolling average, 50 ppmvd @ 0% on a rolling 7 day average, and 182.3 tons per year (tpy).
- FCU – the permit for the Refinery limits SO_2 to: 25 ppmvd @ 0% O2 on a 365 day rolling average, 50 ppmvd @ 0% on a rolling 7 day average, and 352 tpy.

[36] Heaters and Boilers Consent Decree, United States, et al. v. Motiva Enterprises LLC, Civil Action No. H-01-0978. 6th amendment, December 2, 2010. https://www.epa.gov/sites/default/files/documents/4thamendedmotiva-cd.pdf

NOx

- For the FCU, the Consent Decrees required selective non-catalytic reduction (SNCR) for NOx Control.
- FCCU – the permit for the Refinery limits NOx to: 137.0 ppmvd @ 0% O2 on a 7 day rolling average basis, and 100.7 ppmvd @ 0% O2 on a 365 day rolling average basis.
- FCU – the permit for the Refinery limits NOx to: 152.0 ppmvd @ 0% O2 on a 30 day rolling average basis, 152.0 ppmvd @ 0% O2 on a 7 day rolling average basis, and 115.2 ppmvd @ 0% O2 on a 365 day rolling average basis.

Particulate Matter (PM)

- Although PM is not specifically addressed in the consent decree, the wet gas scrubbers for the FCCU and the FCU also control PM.
- FCCU – the permit for the Refinery limits PM to 1 lb/100 of coke burn (based on Subpart J applicability, see below) and 203 tpy.
- FCU – the permit limits PM to the emission limits listed in 7 DE Admin Code 1105, Section 5.2 (see below).

Agreement Governing the Acquisition and Operation of Delaware City Refinery

On May 31, 2010 DNREC and Delaware City Refining Company, LLC (DCRC) entered into an agreement[37] (Appendix 8-14) to address and clarify certain regulatory considerations relevant to DCRC's acquisition and operation of the facility. The facility had been previously owned and operated by The Premcor Refining Group, Inc. (Premcor).

The agreement set NOx caps for the refinery, which were reduced over time. The current NOx Cap is 1,650 tpy. 7 DE Admin Code 1142[38] was revised to incorporate the NOx Caps (see below). Also, as part of the agreement, DCRC was required to submit a plan for achieving NOx emissions reductions consistent with the emission limits reflected by the NOx Caps. Subsequently, DCRC installed SNCR on the FCCU, as part of the NOx control plan.

[37] Agreement Governing the Acquisition and Operation of Delaware City Refinery. May 31, 2010. (Appendix 8-14).
[38] 7 DE Admin. Code 1142. Specific Emission Control Requirements. https://regulations.delaware.gov/AdminCode/title7/1000/1100/1142.pdf

State and Federal Regulations/Rules

The following is a summary of some of the State of Delaware regulations and Federal Rules that apply to the Refinery:

7 DE Admin. Code 1142

7 DE Admin Code 1142 – Specific Emission Control Requirements applies to sources at the Refinery. Section 2.0 of the regulation addresses the control of NOx emissions from industrial boilers and process heaters at petroleum refineries. The regulation sets the following NOx emission limits:

- Section 2.3.1.3: For Boiler 1, Boiler 3, and Boiler 4, 0.015 lb/MMBTU, on a 24-hour rolling average basis.
- Section 2.3.1.4: For the FCCU Carbon Monoxide Boiler, 20 ppmvd @ 0% O2 on a 365 day rolling average basis, and 40 ppmvd @ 0 % O2 on a 7-day rolling average basis.
- Section 2.3.1.5: For any unit not covered by 2.3.1.3, or 2.3.1.4 0.04 lb/MMBTU, on a 24-hour rolling average basis.

As an alternative to complying with one of more of the unit specific emission limitations specified above, the Refinery can limit NOx to a yearly facility-wide cap, as detailed below. In addition, all future growth at the refinery must occur under this NOx cap. The 1,650 NOx cap did not go into place until January 1, 2015.

- Section 2.3.2.3: 1,650 tons per year, evaluated over each twelve (12) consecutive month rolling period, commencing with the twelve (12) month rolling period beginning on January 1, 2015 and ending on December 31, 2015, and continuing thereafter. In addition, all future growth at the refinery must occur under this NOx cap.

7 DE Admin. Code 1104 – PM[39]

Regulation 1104 – Particulate Emissions from Fuel Burning Equipment applies to the Refinery. Section 2.0 – Emission Limits, applies to fuel burning equipment at the Refinery that has a heat capacity is 1,000,000 British Thermal Units (BTU) per hour or more. Regulation 1104 does not apply to the FCCU and FCU, since they are specifically covered under 7 DE Admin Code 1105 (see below). The regulation sets the following PM emission limits:

- Section 2.1: No person shall cause or allow the emission of particulate matter in excess of 0.3 lb per MMBTU heat input, maximum two-hour average, from any fuel burning equipment.
- Section 2.2: No person shall cause or allow the emission of particulate matter in excess of 0.3 lb per MMBTU heat input, maximum 30-day rolling average, from any fuel burning equipment.

7 DE Admin. Code 1105 – PM[40]

Regulation 1105 – Particulate Emissions from Industrial Process Operations applies to the Refinery. Section 5.1 applies to the FCCU and sets restrictions on particulate matter emissions as shown in Table 8-6.

Table 2. Allowable Mass Emission Rate From Catalytic Cracking Operations

Coke Burn-Off Rate (Pounds per Hour)	Mass Emission Rate (Pounds per Hour)
7,000	50
14,000	100
21,000	150
28,000	200
42,000	300
56,000	400
70,000	500

[39] 7 DE Admin. Code 1104 Particulate Emissions from Fuel Burning Equipment. https://regulations.delaware.gov/AdminCode/title7/1000/1100/1104.pdf

[40] 7 DE Admin. Code 1105. Particulate Emissions from Industrial Process Operations. https://regulations.delaware.gov/AdminCode/title7/1000/1100/1105.pdf

Section 5.2 applies to the FCU and sets and sets restrictions on particulate matter emissions as shown in Table 8-7.

Table 3. Allowable Mass Emission Rate From Fluid Coking Operations

Process Weight Rate (Barrels per Day of Fresh Feed)	Mass Emission Rate (Pounds per Hour)
5,000	15
10,000	30
15,000	50
20,000	80
30,000	100
40,000	125
50,000	150

<u>40 CFR Part 60, Subpart J</u>

NSPS Subpart J applies to the FCCU at the refinery and limits particulate matter emissions to 1.0 kg/Mg (2.0 lb/ton) or 1 lb/1,000 lb of coke burn-off[41].

Conclusion

Delaware disagrees the commentors statement that Delaware must conduct a four-factor analysis for the Refinery. Delaware chose not to perform a four-factor analysis on the Refinery because MANE-VU modeling showed its impact on visibility impairment was low and therefore did not require further analysis. In addition, Delaware believes that the Refinery is currently well controlled through existing state regulations and Consent Decrees.

[41] Subpart J— Standards of Performance for Petroleum Refineries. EPA. 39 FR 9315. March 8, 1974.

<u>Comment 5 – Sierra Club et al.</u>

The Draft Haze Plan provides no indication that all of the consent decree limits [at the Refinery] were incorporated into enforceable permits, or that the consent decree itself still binds the Refinery— indeed, the case docket cited in the Draft Haze Plan (at 91) shows that it was terminated by 2017, or possibly earlier. United States v. Motiva Enterprises, No. 4:01-cv-00978 (S.D. Tex.).

<u>Department Response</u>

Delaware disagrees with the Commentors statement that the consent decree does not apply to the Refinery, since it has been terminated. The consent decree is still binding for the current owners of the Refinery – PBF Energy.

The refinery has had many owners since going on-line in 1956. On May 1, 2004, ownership of the Motiva Refinery passed to Premcor, Inc., and on September 1, 2005 Valero Energy Corporation acquired Premcor, Inc. In November 2009, Valero discontinued production at the refinery and idled the facility. PBF Energy completed the purchase of the refinery from Valero Energy Corporation on June 1, 2010 and restarted the refinery in 2011.

Consent decrees can only be terminated with an order from the court. If a named party in the consent decree wishes to terminate their participation in the consent decree, they must make a "Motion to Terminate Consent Decree". The resulting termination order only affects the precisely named parties. PFB Energy has made no such "Motion to Terminate Consent Decree"; therefore, the consent decrees are still in effect for the current owners of the Refinery.

The termination order cited by the Commentor, [United States v. Motiva Enterprises, No. 4:01-cv-00978 (S.D. Tex.)] applies to a previous owner of the Refinery (Motiva Enterprises LLC), not the current owner – PBF Energy.

<u>The termination order states</u>:

> "*Upon consideration of the Joint Unopposed Motion to Terminate Consent Decree filed by Defendants Motiva Enterprises LLC…("the Shell Defendants"); plaintiff of the United States of America…and the Court finding that it is in the public interest to terminate the Heaters and Boilers Consent Decree entered in this case on August 20, 2001 (Doc. No.23); it is hereby*
>
> *ORDERED that the Joint Motion to Terminate Consent Decree is GRANTED; and it is*

> *FURTHER ORDERED that the Heaters and Boilers Consent Decree is hereby terminated with respect to the Shell Defendants, specifically as to the following refineries, not or formerly owned and/or operated by the Shell Defendants:*
>
> - *Delaware City, Delaware (formerly Motiva)…"*

Therefore, the Consent Decree is still binding for PBF Energy, the current owners of the Refinery. In addition, the emission limits set in the Consent Decree are currently being updated in the Title V permit for the Refinery[42].

<u>Comment 6 – Sierra Club et al.</u>

"On July 8, 2021, EPA issued a memo which additionally clarified certain aspects of the revised Regional Haze Rule and provided further information to states and EPA regional offices regarding their planning obligations for the Second Planning Period. EPA's July 2021 "Clarification Memo" confirms that certain aspects of the Draft Haze Plan are fundamentally flawed and cannot be approved. Particularly relevant here, EPA made clear that States must secure additional emission reductions that build on progress already achieved; there is an expectation that reductions are additive to ongoing and upcoming reductions under other CAA programs."

<u>Department Response</u>

In the RH SIP, (Section 8.6, pages 76-83) Delaware details several "new" control measures and one facility shutdown (McKee Run), those that have been adopted since 2007. These measures will build upon the progress the state has already achieved in improving visibility in Class I states, as detailed below:

<u>Shutdowns</u>

Delaware is expecting additional emissions reductions from the shutdown of City of Dover, McKee Run Generating Station, effective November 12, 2021. Delaware is relying on the shutdown to make reasonable progress in the 2nd implementation period.

[42] "Approving Delaware City Refining Company ("DCRC") revised Draft Title V Permit Renewal for the Delaware City Refinery ("DCR"), located on a 5,000-acre tract between U.S. Route 13 and Delaware Route 9, at 4550 Wrangle Hill Road, Delaware City, Delaware." DNREC. May 16, 2022. https://dnrec.alpha.delaware.gov/secretarys-orders/permitting/

State Level Regulatory Amendments

Delaware has promulgated several new emissions reductions programs that were not included in the 1st regional haze RH SIP. The following regulations are EPA approved regulations that are in the Delaware SIP and Delaware is relying on these regulations to make reasonable progress in the 2nd implementation period:

- Regulation 1108, Sulfur Dioxide Emissions from Fuel Burning Equipment (Amendments effective 09/11/08)[43]
- Regulation 1124, Section 11.0, Mobile Equipment Repair and Refinishing, VOC emission control (Amendments effective 10/11/10)[44]
- Regulation 1124, Sections 26.0 and 36.0, Gasoline Dispending Facilities - Decommissioning of Stage II Vapor Recovery and Stage I Enhanced Vapor Recovery, VOC emission control (Amendments effective 7/11/20)[45]
- Regulation 1141 Section 2.0, Consumer Products, VOC emission control (Amendments effective 4/11/09)[46]
- Regulation 1141 Section 3.0, Portable Fuel Containers, VOC emission control (Amendments effective 4/11/10)[47]
- Regulation 1141, Section 4, Adhesives and Sealants, VOC emission control (Amendments effective 4/11/09)[48]

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[43] "Approval and Promulgation of Air Quality Implementation Plans; Delaware; Administrative and Non-Substantive Amendments to Existing Delaware SIP Regulations." EPA Final Rule. 75 FR 48566. August 11, 2010. https://www.govinfo.gov/content/pkg/FR-2010-08-11/pdf/2010-19571.pdf

[44] "Air Plan Approval; Delaware; Amendments To Control of Volatile Organic Compounds Mobile Equipment Repair and Refinishing Rule Regulation." EPA Final Rule. 87 FR 18699. March 31, 2022. https://www.govinfo.gov/content/pkg/FR-2022-03-31/pdf/2022-06615.pdf

[45] "Approval and Promulgation of Air Quality Implementation Plans; Delaware; Removal of Stage II Gasoline Vapor Recovery Program Requirements and Revision of Stage I Gasoline Vapor Recovery Program Requirements". EPA Final Rule. 87 FR 35423. June 10, 2022. https://www.govinfo.gov/content/pkg/FR-2022-06-10/pdf/2022-12236.pdf

[46] "Approval and Promulgation of Air Quality Implementation Plans; Delaware; Administrative and Non-Substantive Amendments to Existing Delaware SIP Regulations." EPA Final Rule. 75 FR 48566. August 11, 2010. https://www.govinfo.gov/content/pkg/FR-2010-08-11/pdf/2010-19571.pdf

[47] "Approval and Promulgation of Air Quality Implementation Plans; Delaware; Limiting Emissions of Volatile Organic Compounds From Portable Fuel Containers. EPA Direct Final Rule. 75 FR 77758. December 14, 2010. https://www.govinfo.gov/content/pkg/FR-2010-12-14/pdf/2010-31305.pdf

[48] Ibid. 47.

- Regulation 1142, Section 2.0, Control of NOx Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries, NOx emission control, New Castle County (Amendments effective 4/11/11)[49]
- Regulation 1146, EGUs, EGU Multi-Pollutant Regulation, SO_2 and NOx emission control (Amendments effective 10/10/09)[50]

In addition, Delaware has submitted the following regulatory amendments to EPA for inclusion into the Delaware SIP and anticipates that they will be accepted into the Delaware SIP by the end of the 2nd Implementation Period (2028):

- Regulation 1108, Sulfur Dioxide Emissions from Fuel Burning Equipment (Amendments effective 7/11/13)[51]
  - Low Sulfur Fuel Requirements, MANE-VU Ask from first Regional Haze Implementation SIPs
- Regulation 1124, Section 33.0, Solvent Cleaning and Drying, VOC emission control (Amendments effective 8/11/21)[52]
- Regulation 1140, Delaware Low Emission Vehicle Program (Amendments effective 3/11/18)[53]
- Regulation 1140, Delaware Low Emission Vehicle Program (Amendments effective 5/1/19)[54,55]

[49] "Approval and Promulgation of Air Quality Implementation Plans; Delaware; Amendments to the Control of Nitrogen Oxides Emissions From Industrial Boilers and Process Heaters at Petroleum Refineries." EPA Final Rule. 77 FR 28489. May 15, 2012. https://www.govinfo.gov/content/pkg/FR-2012-05-15/pdf/2012-11656.pdf

[50] "Approval and Promulgation of Air Quality Implementation Plans; Delaware; Amendment to Electric Generating Unit Multi-Pollutant Regulation". EPS Final Rule. 75 FR 12449. March 16, 2010. https://www.govinfo.gov/content/pkg/FR-2010-03-16/pdf/2010-5581.pdf

[51] 7 DE Admin. Code 1108. Sulfur Dioxide Emissions from Fuel Burning Equipment. https://regulations.delaware.gov/AdminCode/title7/1000/1100/1108.pdf

[52] 7 DE Admin. Code 1124. Control of Volatile Organic Compound Emissions. https://regulations.delaware.gov/AdminCode/title7/1000/1100/1124.pdf

[53] 7 DE Admin. Code 1140. Delaware Low Emission Vehicle Program. https://regulations.delaware.gov/AdminCode/title7/1000/1100/1124.pdf

[54] Ibid. 54.

[55] EPA has put a hold on the review of this SIP submittal from Delaware, due to the September 27, 2019, withdrawal of a 2013 CAA "Section 209" Waiver to California, regarding Motor Vehicle Emission and Fuel Standards. While the Clean Air Act preempts all other states from setting their own vehicle emission standards, California can request a waiver to do so if it determines that its standards are at least as protective of public health and welfare as federal standards issued by the U.S. Environmental Protection Agency.

MANE-VU Asks

Delaware revised the permits for Christiana Energy Center (Units 11 and 14), Delaware City Energy Center (Unit 10) and West Energy Center (Unit 10), to require the use of Water Injection and add an 88 ppm NOx limit for the months of April and October. In accordance with Regulation 1148, Control of Stationary Combustion Turbine Electric Generating Units[56]; the previous NOx limits were 88 ppm during the ozone season (May-Sept). The new permits were issued on May 19, 2021 (Appendix 10-2).

Clarification "Old" vs. "new" control measures/shutdowns

"New" control measures or shutdowns are those that were in place 2008 and later. These later measures/shutdowns were not included in Delaware's 1st RH SIP (submitted to EPA on September 24, 2008), since that RH SIP was well into development by 2008. Therefore, they are considered "new" to Delaware's RH SIP, post-2007.

In sections 8.6.1, 8.6.2 and 8.6.3, and 8.6.5 of Delaware's RH SIP Delaware goes on to describe "Delaware-specific measures". Control measures that had been accepted into Delaware's SIP[57] and were also included in Delaware's 1st RH SIP (submitted to EPA on September 24, 2008), were referred to as "existing". Delaware now realizes that the use of the word "existing" may be unclear; therefore, Delaware will update the RH SIP text to list these "Delaware-specific measures" as "old". See below for details of the changes.

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[56] 7 **DE Admin. Code** 1148, "Control of Stationary Combustion Turbine Electric Generating Units." https://regulations.delaware.gov/AdminCode/title7/1000/1100/1148.pdf. Regulation 1148 requires subject stationary combustion turbine EGUs with a base-load nameplate capacity of one MW or greater to limit NOx emissions during the ozone season (May – September): 42 ppmv for natural gas and 88 ppmv for fuel oil.

[57] Approval and Promulgation of Implementation Plans. Delaware. 40 CFR Subpart I §52.420. Page 769. EPA. July 1, 2020 Edition. https://www.govinfo.gov/content/pkg/CFR-2020-title40-vol3/pdf/CFR-2020-title40-vol3.pdf

Bold Bracketed changes to Delaware's Regional Haze SIP:

"8.6.1 EGU Emissions Controls that Will Reduce Emissions by 2028...

Delaware-specific measures for EGUs that will reduce emissions by 2028 are:

***[~~Existing~~ Old]** – Accepted into the Delaware SIP (1st RH SIP)*

- *Regulation 1144, Control of Stationary Generator Emissions, SO2, PM, VOC and NOx emission control (Original regulation effective 1/11/06)*
- *Regulation 1146, EGUs, EGU Multi-Pollutant Regulation, SO2 and NOx emission control (Original regulation effective 12/11/06)*
- *Regulation 1148, Control of Stationary Combustion Turbine Electric Generating Unit Emissions, NOx emission control (Original regulation effective 7/11/07)*
- *Facility and Unit shutdowns (Delaware's 1st RH SIP – Appendix 9-8)…*

8.6.2 Non-EGU Point Source Emission Reductions Expected by 2028 Due to Ongoing Air Pollution Control Programs…

Delaware-specific measures for Non-EGU Point Sources that will reduce emissions by 2028 are:

***[~~Existing~~ Old]** – Accepted into the Delaware SIP (1st RH SIP)*

- *Regulation 1142, Section 2.0, Control of NOx Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries, NOx emission control (Original regulation effective 12/1/01)*
- *Regulation 1142, Section 2.0, Control of NOx Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries, NOx emission control, New Castle County (Original regulation effective 7/11/07)*

o *Delaware City refinery is subject to an enforceable emission cap for NOx.*

- *Regulation 1124, Section 46.0, Crude Oil Lightering Operations, VOC emission control (Original regulation effective 5/11/07)*
- *Facility and Unit shutdowns (Appendix 9-8 of Delaware's first Implementation Plan)…*

8.6.3 Area Sources Controls Expected by 2028 Due to Ongoing Air Pollution Control Programs…

Delaware-specific measures for Non-EGU Point Sources that will reduce emissions by 2028 are:

***[~~Existing~~ Old]** – Accepted into the Delaware SIP (1st RH SIP)*

- *Regulation 1142, Section 2.0, Control of NOx Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries, NOx emission control (Original regulation effective 12/1/01)*
- *Regulation 1142, Section 2.0, Control of NOx Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries, NOx emission control, New Castle County (Original regulation effective 7/11/07)*
- *Delaware City refinery is subject to an enforceable emission cap for NOx.*
- *Regulation 1124, Section 46.0, Crude Oil Lightering Operations, VOC emission control (Original regulation effective 5/11/07)*
- *Facility and Unit shutdowns (Appendix 9-8 of Delaware's first Implementation Plan)…*

8.6.5 Mobile Source Controls Expected by 2028 due to Ongoing Air Pollution Control Programs…

Delaware-specific measures for Area Sources that will reduce emissions by 2028 are:

***[~~Existing~~ Old]** - Accepted into the Delaware SIP (1st RH SIP)*

- *Regulation 1131, Low Enhanced Inspection and Maintenance Program (Amendments effective 10/11/01)*
- *Regulation 1132, Transportation Conformity Regulation (Amendments effective 11/11/07)*
- *Regulation 1140, Delaware Low Emission Vehicle Program (Amendments effective 10/11/99)*
- *Regulation 1145, Excessive Idling of Heavy Duty Vehicles (Original regulation effective 4/11/05)*
- *40 CFR Parts 80, 85, and 86 Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements.*
- *40 CFR Parts 69, 80, and 86 Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle*

Standards and Highway Diesel Fuel Sulfur Control Requirements.

Conclusion

Delaware believes that the implementation during the second implementation period of new control measures and MANE-VU Ask #5, along with the shutdown of McKee Run, will build on the progress that Delaware has already achieved in to improve visibility in Class I areas.

Delaware has also added federal register notice citations above regarding EPA approval of regulatory amendments into Delaware's SIP[58], for reference.

Comment 7 – EPA Region III

"Section 110(a) of the Clean Air Act (42 USC section 7410(a)) requires that SIPs contain enforceable emissions limitations and other control measures, means, or techniques relied on, as well as a program for the enforcement of the measures. Therefore, any emission limits or other control measures relied on by Delaware to make reasonable progress must be accompanied by SIP provisions to ensure that the emission limits or other control measures are enforceable. EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 20, 2019; hereafter "Guidance") at 42. See also 40 CFR 51.308(f)(2).

[58] Ibid 58.

Department Response

Section 8.6, pages 76-81, of the RH SIP includes a list of regulatory amendments (control measures), which Delaware is relying on to make reasonable progress. These regulatory amendments have been accepted into Delaware's SIP. Delaware has also added federal register notice citations, **See Comment 6**, regarding EPA approval of regulatory amendments into Delaware's SIP[59], for reference.

In addition, Delaware included in Attachment 10-2 to the SIP, copies of the three Calpine Title V permits that had new NOx emission limits added, see Section 10.1 and 10.5 of the SIP.

Comment 8 – EPA Region III

"If Delaware determines that no additional (i.e., new) measures are necessary to make reasonable progress, it must then determine whether existing measures are necessary to make reasonable progress. See section 4 (pages 8 – 12) of the Clarifications Memo for information on determining when a source's existing measures are necessary to make reasonable progress. Generally, a source's existing measures are needed to prevent future emission increases and are thus needed to make reasonable progress. If Delaware concludes that the existing controls at a selected source are necessary to make reasonable progress, Delaware must adopt emissions limits based on those controls as part of its long-term strategy for the second planning period and include those limits in its SIP (to the extent they do not already exist in the SIP)."

Department Response

Delaware had several sources for which it conducted a four-factor analysis, but did not identify any new/upgraded control measures that were reasonable to implement, see Section 10.0 of Delaware's RH SIP. Delaware's existing regulations include enforceable emission limits applicable to the facilities. In addition, the limits are codified in the Title V permits for each of the facilities.[60]

[59] Ibid 58.

[60] Facility and Title V Permit Number: Edge Moor (Calpine) – AQM-003/00007, Garrison (Calpine) – AQM-001/00245, Hay Road (Calpine) – AQM-003/00388, Indian River (NRG) – AQM-003/00001, and Van Sant (City of Dover) – AQM – 001-00076.

Comment 9 – EPA Region III

"With respect to measures identified through a 4-factor analysis, EPA has clarified that we anticipate that many states 'will find that new (i.e., additional) measures are necessary to make reasonable progress. All new measures must be included in the SIP.' EPA's Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021); CAA 169A(b)(2); 40 CFR 51.308(f)(2). If these measures are included in a Title V permit, that permit must be in the SIP in order for those measures to be federally enforceable and permanent; this is relevant to the Delaware SIP given that there are facilities whose Title V permits will be updated to incorporate control measures for NOx.[3]"

"[3] See Delaware City Energy Center (Calpine) on Page 112 and West Energy Center (Calpine) Unit 10 on Page 117"

Department Response

Delaware disagrees with the Commentors statement that the Title V permits for Delaware City Energy Center (Calpine) and West Energy Center (Calpine) were not included in the SIP. The permits for the two facilities are located in Appendix 10-2 of Delaware's RH SIP, pages 43 and 75 respectively.

Comment 10 – EPA, Region III

"The 4-factor analyses in Section 10 of the Draft SIP would benefit from additional information and context to support its conclusions. For example, some sources do not have a dollars-per-ton cost estimate in their Cost of Compliance analysis;[1] other sources have dollars-per-ton cost estimates which are deemed to be economically infeasible but do not have an explanation as to why.[2] The EPA recommends updating the Draft SIP to include this information, and also provide additional details on how the costs and cost/ton numbers were derived, and the emissions and emissions reductions associated with the potential controls. We note that many of the sources are relatively low-emitting and operate relatively few hours per year. Providing more detailed information in the record that documents Delaware's information and rationale underlying its decisions will assist EPA in evaluating the overall four factor analysis conclusions. The Court of Appeals for the Third Circuit recently has spoken to the importance of the information developed by the state in support of EPA's administrative record in SIP decisions. See, e.g., Sierra Club v. EPA, 972 F.3d 290 (3d Cir. 2020)."

"[1] See Section 10.1.1, Edge Moor (Calpine) Units 3 and 4 on Page 106

[2] See Section 10.1.1, Christiana Energy Center (Calpine) on Page 104, and Edge Moor (Calpine) Unit 5 on Page 106; Section 10.5, Christiana Energy Center (Calpine) on Page 111, Delaware City Energy Center (Calpine) on Page 113, Van Sant (City of Dover) on Page 116, and West Energy Center (Calpine) on Pages 118 and 119"

Department Response

Cost Analysis

Cost effectiveness for the following facilities is listed in Delaware's RH SIP, see below for excerpts. A detailed description of the analyses can be found in Appendix 10-1 of the RH SIP "Facility Responses to Delaware Department of Natural Resources and Environmental Control Request for Information for MANE-VU "Asks".

Christiana Calpine – (page 105 of RH SIP)

Water Injection

- Calpine rents water demineralization units to supply water to each unit for WI for the ozone season. The WI system is not weatherized to operate in cold temperatures. The system could be damaged if operated in cold weather as is it currently designed. While the water tanks remain at the site, the demineralization equipment is removed each winter and returned to the rental company.

- Cost of Compliance - Calpine evaluated the cost of updating the system for cold weather operations. The WI system would require a new heated building in order to operate during cold weather, an estimated annual cost of $5,300/ton of NOx removed for Unit 11 and $2,300/ton for Unit 14. In addition, there would be significant space constraints associated with placing a new structure at the facility. Therefore, the analysis indicated that it was not economically feasible to weatherize the system, to allow for year-round WI. Costs for year-round water rentals are based on current rental agreements at the facility and recent purchase costs of similar building structures by the company.

Edgemoor Calpine (Page 106 of the RH SIP)

Selective Non-Catalytic Reduction (SNCR)
Calpine evaluated the technical and economic feasibility of operating the SNCR year round.

Units 3 and 4

Units 3 and 4 burn natural gas only. The SNCR systems were originally installed to control NOx emissions from coal firing, when coal was the primary fuel for these units. Though the Title V permit still allows coal to be combusted, no coal has been combusted in the units since 2010. In 2019 Unit 3 operated only 572 hours and Unit 4 615 hours.

- Cost of Compliance - The SNCR systems are not designed to be operated while burning natural gas and would need to be reconfigured, at a cost of $500,000 per unit. Information on costs were calculated using the approach outlined in EPA's Control Cost Manual. The flue gas temperatures are compatible with effective SNCR operation only at high (>80%) load operations. Therefore, only marginal (30%) NOx reductions are expected with SNCR Units with such a limited operation. Therefore, the analysis indicated that it is not cost effective to operate the existing SNCR systems when burning natural gas.

Unit 5

Unit 5 burns both natural gas and oil. The SNCR is used when firing fuel oil. When firing natural gas, the maximum output is limited to about 250 MW; oil firing must be added to achieve higher loads. The furnace temperature at the SNCR urea injection location does not reach the temperatures needed for effective SNCR operational until the boiler reaches loads of about 300 to 350 MW. Due to these limitations and the SNCR has been rarely used. Calpine believes that the SNCR could be modified to provide some degree of NOx reduction when firing natural gas and at lower loads, but that the reconfiguration would not be cost effective. In 2019 Unit 5 operated only 774 hours.

- *Cost of Compliance* - Estimated capital costs would be $300,000 and daily operating costs would be $4,000. Calpine estimated an annual cost of $10,000/ton of NOx removed. Therefore, the analysis indicated that it is not cost effective to run the SNCR while burning natural gas and at lower loads. Information on costs were calculated using the approach outlined in EPA's Control Cost Manual.

Christiana Energy Center Calpine – Page 111 of the RH SIP

<u>Selective Catalytic Reduction (SCR) (new control)</u>

- Calpine evaluated the cost of installing SCR on the unit. Installation of SCR would require new buildings to be erected on site. Calpine responded that there would be significant space constraints associated with placing new structures at the facility. In addition, the site is unmanned and would present challenges for managing operations and maintenance for the complex new control systems.

- <u>Cost of Compliance</u> - Calpine calculated that the capital costs for installation of SCR at Christiana Energy Center would be $3,000,000 and estimated annual costs of $71,000/ton of NOx removed for Unit 11 and $31,000/ton for Unit 14. Therefore, the analysis indicated that it was not economically feasible to install an SCR. Information on costs were calculated using the approach outlined in EPA's Control Cost Manual. In addition, Calpine used previous bids from an evaluation of the potential for retrofitting SCR on several combustion turbines at its facilities in New Jersey, to help determine estimated costs.

Delaware City Energy Center Calpine (page 114 of the RH SIP)

<u>Water Injection (existing control)</u>

- Calpine rents water demineralization units to supply water to the unit for WI for the ozone season. The WI system is not weatherized to operate in cold temperatures. The system could be damaged if operated in cold weather as is it currently designed. While the water tanks remain at the site, the demineralization equipment is removed each winter and returned to the rental company.

- Cost of Compliance - Calpine evaluated the cost of updating the system for cold weather operations. The WI system would require a new heated building in order to operate during cold weather, an estimated annual cost of $14,700/ton of NOx removed. In addition, there would be significant space constraints associated with placing a new structure at the facility. Therefore, the analysis indicated that it was not economically feasible to weatherize the system, to allow for year-round WI. Costs for year-round water rentals are based on current rental agreements at the facility and recent purchase costs of similar building structures by the company.

SCR (new control)

- Installation of SCR would require new buildings to be erected on site. Calpine responded that there would be significant space constraints associated with placing new structures at the facility. In addition, the site is unmanned and would present challenges for managing operations and maintenance for the complex new control systems.
- Cost of Compliance - Calpine calculated that the capital costs for instillation of SCR at Delaware City Energy Center would be $2,800,000 and estimated annual costs of $147,000/ton of NOx removed. Therefore, the analysis indicated that it was not economically feasible to install SCR. Information on costs were calculated using the approach outlined in EPA's Control Cost Manual. In addition, Calpine used previous bids from an evaluation of the potential for retrofitting SCR on several combustion turbines at its facilities in New Jersey, to help determine estimated costs.

West Energy Center Calpine (pages 117-119 of the RH SIP)

WI (existing control)

- Calpine rents water demineralization units to supply water to the unit for WI for the ozone season. The WI system is not weatherized to operate in cold temperatures. The system could be damaged if operated in cold weather as is it currently designed. While the water tanks remain at the site, the demineralization equipment is removed each winter and returned to the rental company.

- Cost of Compliance - Calpine evaluated the cost of updating the system for cold weather operations. The WI system would require a new heated building in order to operate during cold weather, an estimated annual cost of $19,000/ton of NOx removed. In addition, there would be significant space constraints associated with placing a new structure at the facility. Therefore, the analysis indicated that it was not economically feasible to weatherize the system, to allow for year-round WI. Costs for year-round water rentals are based on current rental agreements at the facility and recent purchase costs of similar building structures by the company.

SCR (new control)

- Calpine evaluated the cost installing SCR on the unit. Installation of SCR would require new buildings to be erected on site. Calpine responded that there would be significant space constraints associated with placing new structures at the facility. In addition, the site is unmanned and would present challenges for managing operations and maintenance for the complex new control systems.
- Cost of Compliance - Calpine calculated that the capital costs for instillation of SCR at West Energy Center would be $3,000,000 and estimated annual costs of $171,000/ton of NOx removed. Therefore, the analysis indicated that it was not economically feasible to install SCR. Information on costs were calculated using the approach outlined in EPA's Control Cost Manual. In addition, Calpine used previous bids from an evaluation of the potential for retrofitting SCR on several combustion turbines at its facilities in New Jersey, to help determine estimated costs.

Technologically Infeasible Controls

In completing the four-factor analysis process, facilities first determined if potential new or upgraded controls were technologically feasible to be used on the emission source in question. Technologically feasible means the controls are compatible with the type of emission source (boiler, turbine, etc.), type of fuel used by the source (coal, fuel oil, natural gas, etc.), or operating conditions (control device temperature requirements, extreme weather condition limitations, etc.).

Delaware did not include $/ton cost estimate for controls that were deemed technologically "infeasible", i.e. not appropriate for the emission source, fuel type, or operating conditions. Therefore, if it was not technically feasible to operate a specific type of control on an emission source, a cost analysis was not applicable and was not conducted. If controls were determined technologically feasible, a cost analysis was conducted.

Economically Infeasible Controls
Most of the cost effectiveness calculations for units at the sources that completed four-factor analyses were $10,000/ton of reduced NOx. Delaware believes this is not cost effective especially given the low operating hours of the units of most of the units, see below for details.

Christiana Calpine year-round water injection was slightly lower, $5,300/ton of NOx removed for Unit 11 and $2,300/ton for Unit 14. But since the WI system would require a new heated building in order to operate during cold weather. The facility determined that there would be significant space constraints associated with placing a new structure at the Christiana, which could potentially increase the overall cost of the project. Taking this into consideration Delaware believed that it is not cost effective to run the Water Injection system year-round.

However, in its analysis, Calpine agreed to rent the demineralization unit for the months of April and October and run the WI system during those months to increase the control of NOx. The facility's Title V permit was revised to reflect the extension of the 88 ppm permit limit and the injection of water during the months of April and October. The new permit was issued on May 19, 2021 (AQM-003/00006) (Appendix 10-2 of Delaware's RH SIP).

Low Operating Hours
Delaware would also like to note that many of the units at the sources had extremely low operating hours, especially combustion turbines that fell under MANE-VU "Ask #5".

As shown in Table 10-5 from the Delaware RH SIP, page 111, these turbines have more recently had low operating hours and average emissions. Therefore, the cost/ton of emissions reduced was not effective, given the low operating hours of the units. Given the recent trend of low operating hours emissions, Delaware believes that additional, year-round controls were not cost effective.
Delaware's RH SIP, Page 111:

Table 1 - Average Operating Hours and NOx Emissions for Units Under "Ask #5"

Facility	Unit	2015-2019 Ave. Annual Operating Hours	2015-2019 Ave. NOx Emissions (tons)
Christiana Energy Center	11	16	1.8
Christiana Energy Center	14	14	1.6
Delaware City Energy Center	10	15	0.4
Indian River	5	20	1.4
VanSant	1	106	4.5
West Energy Center	10	21	1.2