A Review of the Ohio Regional Haze State Implementation Plan

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On behalf of

National Parks Conservation Association and the Sierra Club

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1 Introduction

This is a report concerning a review of the Ohio Regional Haze State Implementation Plan (SIP).[1] Emissions and controls information for all EGUs were downloaded from EPA's Air Markets Program Data (AMPD) website.[2] Additional information was obtained from the Energy Information Agency (EIA).[3] Lastly, I reviewed the Title V permits for a number of units.

2 Apparent Errata

2.1 Footnote 25 on page 31 of Ohio's report is missing. The SDA cost effectiveness calculations in Appendix B are labeled as "Dry Sorbent Injection Cost." Footnote "b" to Table 4-4 on page 4-8 of the Carmeuse report is not referenced in that table. The first sentence of the section on page 57 of Ohio's report relating to the June 22, 2020 VISTAS Ask appears to have a typo.

3 General

3.1 Little documentation has been provided to support a number of assertions contained in some cost-effectiveness calculations. For those cost-analyses that do not employ Control Cost Manual approved algorithms or cost models, adequate documentation (e.g., vendor quotes, actual costs from a similar facility, generally accepted estimates) should be provided to support any of the capital control costs provided. It is assumed that the Department has procedures to protect confidential business information, should that be asserted.

3.2 Ohio must include in its final state implementation plan fully executed and enforceable Director's Findings and Order requiring the permanent retirement of Miami Fort Power Station and Zimmer Power Station. On page 13 of the Ohio Regional Haze SIP,[4] Ohio states that it issued a Director's Final Findings and Orders (Appendix C) which establish an enforceable requirement for the permanent shut down of the coal-fired operations at the boilers at Miami Fort Power Station and Zimmer Power Station by no later than January 1, 2028. However, the document present in Appendix C is not executed. Furthermore, the SIP lacks enforceable requirements that reflect the permanent shut downs. Therefore, Ohio should ensure that its final SIP contains an executed copy.

3.3 Ohio should not rely on CSAPR to drive emissions reductions. Through its proposed SIP amendments, Ohio states that EGUs "are subject to CSAPR [Cross State Air Pollution Rule], which provides significant economic incentive to operate and optimize SO_2 and NOx emissions controls. This incentive will become stronger with additional reductions

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[1] See https://www.epa.ohio.gov/dapc/sip/haze.
[2] See https://ampd.epa.gov/ampd/. This information is compiled and assessed in spreadsheets that are included in this analysis.
[3] See https://www.eia.gov/electricity/data/eia923/.
[4] This report is based on a review of the "Regional Haze State Implementation Plan for the Second Implementation Period, prepared by: The Ohio Environmental Protection Agency Division of Air Pollution Control, DRAFT May 2021." Hereafter referred to as the "Ohio SIP."

to NOx allocations with the proposed Revised CSAPR Update."[5] First, as demonstrated in several places in this report, some of the EGUs reviewed have historically demonstrated they are capable of better emission control than they are currently achieving. If CSAPR did indeed provide an economic incentive to these EGUs to reduce their emissions, then certainly those EGUs that already have the controls installed (e.g., SCRs and scrubbers) would operate them in an optimal fashion, since doing so only involves additional reagent and potential operational and maintenance issues.

Second, there does not appear to be any economic incentive from CSAPR that would cause EGUs to either run their existing controls at their full performance potential, or to install new controls. According to EPA, a fundamental tenet of any cap and trade program is that, "the cap and associated allowance market creates a monetary value for allowances, providing sources with a tangible incentive to decrease emissions."[6] This is perhaps the single most important aspect of a successful emissions trading program, because if market forces do not adequately value allowances, there is little to no incentive for sources to install pollution controls or take other measures to reduce emissions.

Unfortunately, that is exactly what has happened to EPA's two premier SO_2 cap and trade programs, the Acid Rain Program (ARP) and CSAPR:[7]

2019 Allowance Prices

- The ARP SO_2 allowance prices averaged less than $1 per ton in 2019.
- The CSAPR SO_2 Group 1 allowance prices started 2019 at $2.31 per ton and remained at that level at the end of the year.
- The CSAPR SO_2 Group 2 allowance prices started 2019 at $2.56 per ton and remained at that level at the end of the year.
- The CSAPR NOx annual program allowances started 2019 at $2.88 per ton and ended 2019 at $2.75 per ton.
- The CSAPR NOx ozone season program allowances started 2019 at $180 per ton and ended 2019 at $93.75 per ton.

As can be seen from the above data, the 2019 average price of SO_2 allowances for the ARP was less than $1 per ton, making them almost worthless. Although the ARP was successful for many years, it no longer provides any incentive to reduce SO_2.

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5 See for instance, page 28.

6 EPA Office of Air and Radiation, "Tools of the Trade, A Guide to Designing and Operating a Cap and Trade Program for Pollution Control" at 1-3 (June 2003), EPA430-B-03-002, *available at* https://www.epa.gov/sites/production/files/2016-03/documents/tools.pdf.

7 2019 Power Sector Programs – Progress Report, page 63, *available at* https://www3.epa.gov/airmarkets/progress/reports/pdfs/2019_full_report.pdf.

Similarly, CSAPR SO_2 allowances ranged between $2.31 and $2.56 per ton in 2019, providing little to no regulatory pressure to control SO_2. EPA concedes this point when it states in relation to the above pricing,

> The 2019 emissions were below emission budgets for the Acid Rain Program (ARP) and for all five Cross State Air Pollution Rule (CSAPR) programs. As a result, the CSAPR allowance prices were well below the marginal cost for reductions projected at the time of the final rule, and are subject, in part, to downward pressure from the available banks of allowances.[8]

In other words, EPA concludes that it was cheaper to buy allowances than to reduce SO_2 emissions. In fact, simple calculations can easily indicate that it is much more expensive to install any type of commonly employed NOx or SO_2 EGU pollution control it is to purchase the necessary CSAPR allowances.

There are many reasons why the price of allowances can collapse. In the case of the ARP, this is primarily due to external market forces that were unanticipated by the program. As the figure below indicates, much of the collapse of the ARP SO_2 allowance market was in fact due to the effect of CAIR, CSAPR, litigation of these programs, and although not shown on the graph, the National Ambient Air Quality Standards ("NAAQS") and Mercury and Air Toxics Standards ("MATS") programs.[9] In other words, trading programs do not operate in a vacuum. There are a number of externalities that can serve as drivers to EGU owners for making economic decisions, including other regulatory programs. Trading programs can, however, remain pertinent if they contain minimum allowance prices—a feature that the ARP and CSAPR lack.[10]

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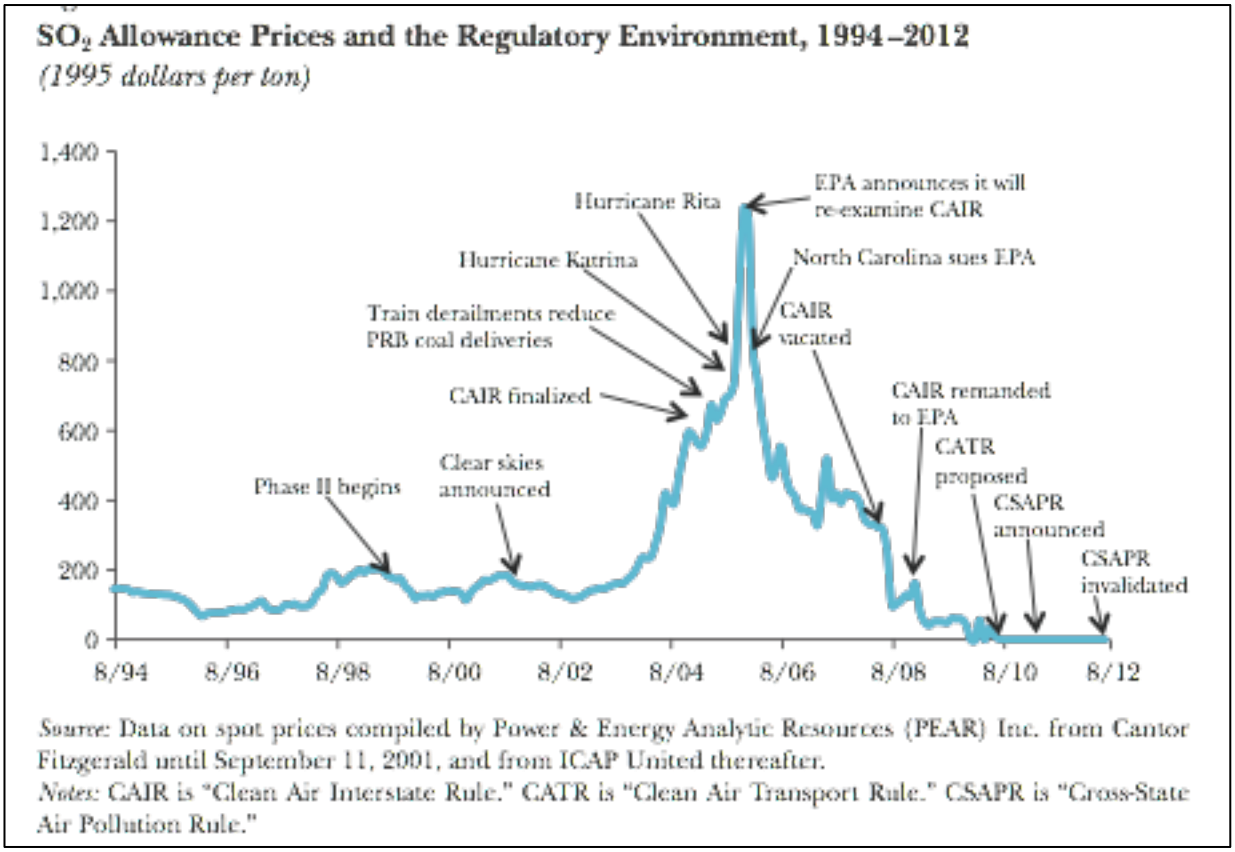
[8] *Ibid*., page 64.

[9] Richard Schmalensee and Robert N. Stavins, *The SO_2 Allowance Trading System: The Ironic History of a Grand Policy Experiment*, 27:1 Journal of Economic Perspectives, 114, fig. 2, *available at* https://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.27.1.103.

[10] In addition, units have reduced operation of existing NOx controls after the price of NOx allowances dropped under the several different trading programs. *See* https://www.tandfonline.com/doi/full/10.1080/10962247.2015.1112317.

Figure 1. The Collapse of the SO_2 Allowances Market in the Acid Rain Program



In summary, the price of CSAPR allowances is so low there is little to no regulatory incentive for participating sources to reduce emissions.

3.4 Ohio has misinterpreted its "robust demonstration" obligation. Ohio concludes that "after fulfilling the source selection and control measure analysis requirements, Ohio has no "robust demonstration" obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B)."[11] In support of its conclusion, Ohio cites to the Regional Haze Guidance.[12] Because Ohio make this statement before it presents any consideration of "the source selection and control measure analysis requirements," it appears that it has adopted a view that because the Class I Areas its sources impact are all below the Uniform Rate of Progress (URP), it is free from any judgement whether it has satisfied its "robust obligation." The Regional Haze Rule makes it clear that this is not the case:

> The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures already

[11] See page 20.
[12] "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003, August 2019." Hereafter referred to as the "Regional Haze Guidance.

> determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. Rather, the rate of progress that will be achieved by the emission reductions resulting from all reasonable control measures is, by definition, a reasonable rate of progress. [I]f a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line.[13]

Thus, the key determinant in whether Ohio's "robust determination" obligation has been satisfied under Section 51.308(f)(3)(ii)(B) is not whether the Reasonable Progress Goal (RPG) of a Class I Area is below that Class I Area's URP, but rather whether Ohio has considered and determined requirements to make reasonable progress based on the four statutory factors. Ohio must consider the four factors regardless of the status of any Class I Area's RPG.

3.5 Ohio should reconsider its conclusions that some units are "effectively controlled." In section III.3.h, Ohio takes the position that a number of EGUs that are already equipped with scrubbers and SCRs are "effectively controlled" for SO_2 and NOx and points to the Regional Haze Guidance to support its position. Ohio concludes that it need not further consider controlling these sources. The following points address this issue:

- Because the Regional Haze Guidance is merely guidance, it does not take precedence over the Regional Haze Rule. In fact, the Regional Haze Rule does not provide any discussion at all concerning the topic of "effective controls." The Regional Haze Rule has long recognized that scrubber upgrades are generally cost-effective and should be examined by states to ensure reasonable progress.[14] To the extent Ohio interprets EPA's guidance as suggesting otherwise, that interpretation has no basis in either the CAA or the Regional Haze Rule.

- In fact, EPA's record for its Oklahoma FIP, indicates that underperforming scrubbers should be evaluated at 98% control (with a floor of 0.04 lbs/MMBtu) for Wet Flue Gas Desulfurization (WFGD) scrubbers, and 95% control (with a floor of 0.06 lbs/MMBtu) for Spray Dryer Absorbers (SDA).[15] Also, The IPM wet FGD Documentation states: "The least-squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the

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[13] See 82 FR 3093 (January 10, 2017).

[14] For instance, see the Final Regional Haze Rule update, 82 Fed. Reg. 3088 (January 10, 2017): Here, EPA explains that Texas' analysis was in part rejected because it did not properly consider EGU scrubber upgrades. Also see the BART Final Rule, 70 Fed. Red. 39171 (July 6, 2005): "For those BART-eligible EGUs with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50 percent, your BART determination should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency."

[15] See 76 FR 81742 (December 28, 2011).

original equipment manufacturers of wet FGD systems, are 0.04 lb/MMBtu."[16] This contrasts with the 90% control threshold, discussed below, that Ohio has adopted. Ohio should therefore review EPA's Texas scrubber upgrade information and incorporate it into its SIP.

- The problems with Ohio's interpretation of the Regional Haze Guidance's advice notwithstanding, Ohio has ignored a key qualifier of that advice. The Regional Haze Guidance states regarding its "effectively controlled" advice that

> [A] state that does not select a source or sources for the following or any similar reasons should explain why the decision is consistent with the requirement to make reasonable progress, i.e., why it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary.[17]

Ohio has arbitrarily failed to consider technically and economically feasible upgrades to scrubbers and SCR systems.

- Although EPA's guidance states, regarding scrubbers installed as a result of regional haze first round requirements, that "we expect that any FGD system installed to meet CAA requirements since 2007 would have an effectiveness of 95 percent or higher,"[18] that does not relieve the state of evaluating achievable, cost-effective emission reductions. Here, a number of examples of non-regional haze requirements (e.g., NSPS, BACT, LAER, and MATS), which could serve as surrogate four-factor analyses, support imposing more stringent control and/or emission limits for SO_2[19] than EPA assumed for first round regional haze controls. For instance many of the EGUs that meet MATS do so by monitoring for HCl and so only control SO_2 indirectly. Even those that do satisfy MATS by controlling SO_2 are (assuming coal) usually limited to 30 day average SO_2 rates of 0.2 lbs/MMBtu, which is often much less stringent than would have been required under a source-by-source BART analysis. In fact, Ohio recognizes this and states:

> [I]t believes the metric of 90% control efficiency noted in the main text of the example [the Regional Haze Guidance example list] is controlling and most appropriate. Ohio believes that conducting a four-factor analysis on a source with an FGD system with 90% control efficiency or greater would likely result in the conclusion that no further controls are necessary.[20]

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16 IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final January 2017, Sargent and Lundy. Page 2.
17 See the Regional Haze Guidance, page 23
18 Regional Haze Guidance, page 24, FN 53. EPA does not distinguish between WFGD and SDA scrubbers.
19 See the example list in the Regional Haze Guidance, pages 23-25.
20 See page 27.

Ohio's approach erroneously assumes that EPA's guidance is "controlling." It is not. Moreover, the state's approach arbitrarily ignores achievable emission reductions. Given EPA's has previously findings that scrubber upgrades can achieve 98% control for WFGD and 95% for SDA, the state must evaluate the cost-effectiveness of those emission limits under the four statutory factors. Many significant wet scrubber upgrades involve relatively low capital expenditures (e.g., liquid to gas improvements such as rings or trays, new spray headers/nozzles, etc.) and often consist of simply running all available absorbers and pumps and utilizing better reagent management or simply using more reagent and/or organic acid additives such as Dibasic Acid (DBA). These types of upgrades will likely result in very cost-effective scrubber upgrades. In fact, it appears that some of these types of upgrades have recently been performed on the Gavin units, discussed below.

3.6 On page 5, Ohio acknowledges that 40 CFR 51.308(f)(2)(i) indicates that states should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. Regarding area sources, Ohio only states that it is focusing on major and minor stationary sources and groups of sources, as it considers these sources are more controllable at the state level and are significant contributors to Regional Haze at Class I areas impacted by sources in Ohio. This statement is essentially the only reasoning that Ohio presents to explain why it has not considered area sources. It is difficult to understand how Ohio can dismiss area sources when it does not appear it has even evaluated area source impacts. This is especially important since Ohio's proposed regional haze SIP does not include any new controls for its point sources, other than controls that are on the books.

3.7 Ohio does not mention the AK Steel facility (now Cleveland-Cliffs) in its SIP. Based on 2017 emissions from the National Emissions Inventory, this facility emits 1,963.3 tons of NOx, 1,962.6 tons of SO_2, and 906.4 tons of PM10. The cumulative Q/d (considering all Class I Areas) for this facility is 179.3, with a high Q/d value at Mammoth Cave of 17.0.[21] This is a significant source of visibility impairing pollution. Therefore, Ohio should explain why this facility was not selected for a four-factor analysis.

4 Discussion of the Cardinal Facility

4.1 Ohio discusses the reasons it did not require that Cardinal Units 1, 2, and 3 investigate scrubber upgrades on page 27. Ohio references a consent decree and without providing a reference to where the requirement appears, suggests that FGDs with approximately 95% control efficiency were installed. An examination of that consent decree appears to indicate that although Cardinal was required to install scrubbers on each of the three units, no actual SO_2 emission limits or scrubber efficiencies were specified for those units.[22]

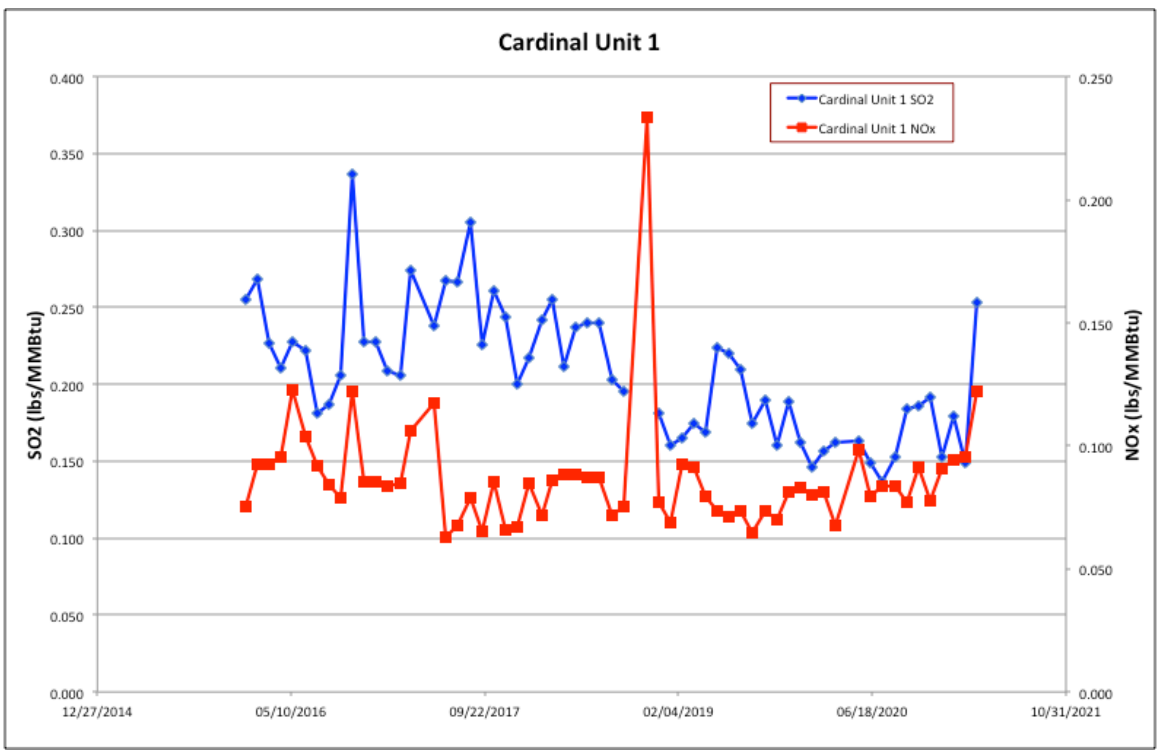
[21] Q/d data retrieved from: https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d.

[22] The Consent Decree referenced by Ohio is located here: https://www.epa.gov/enforcement/consent-decree-and-modifications-american-electric-power-service-corporation. The original consent decree is over 100 pages in length. There are first, second, third, and fifth modifications listed (no fourth

Ohio further states that its permits impose 30 day rolling average SO_2 emissions limits of 1.056 lb/MMBtu on Units 1 and 2, and 0.66 lb/MMBtu on Unit 3. However, these limits are much less stringent than 95% control, and as Ohio notes, the Cardinal units are comfortably operating well under these limits. EPA's MATS Rule for power plants requires that Cardinal meet either a Hydrogen Chloride (HCl) limit of 0.002 lb/MMBtu (or 0.02 lb/MWh), or because it has an FGD an SO_2 limit of 0.2 lb/MMBtu (or 1.5 lb/MWh) on a 30 BOD average. Since Cardinal is not meeting the SO_2 limit, presumably it is complying with MATS by meeting the HCL limit. Thus, there appears to be no meaningful restrictive SO_2 limit and therefore no guarantee that the scrubbers for these units will continue to perform at these levels.

4.2 Ohio uses annual emission averages to illustrate its points. Instead, because emission limits are conditioned in the regional haze program on the basis of 30 day rolling averages, or better yet, 30 Boiler Operating Day (BOD) averages, Ohio should base its evaluations on that type of emission data. Below are 30 day monthly averages for the Cardinal Units:[23]

Figure 2. Cardinal Unit 1 Monthly Average SO_2 and NOx emissions.



modification listed). Because these documents do not specify either SO_2 emission limits or scrubber operating efficiencies for the Cardinal units, Ohio must impose an emission limit necessary to ensure reasonable progress toward the national visibility goal, as required by the Clean Air Act and the Regional Haze Rule. See e.g., 42 U.S.C. 7410(a)(2).

[23] See the workbook, "OH EGU Emissions.xlsx," worksheet "OH Selected Monthly." Note that in some cases the scales have been modified to separate the SO_2 and NOx curves.

Figure 3. Cardinal Unit 2 Monthly Average SO_2 and NOx emissions.

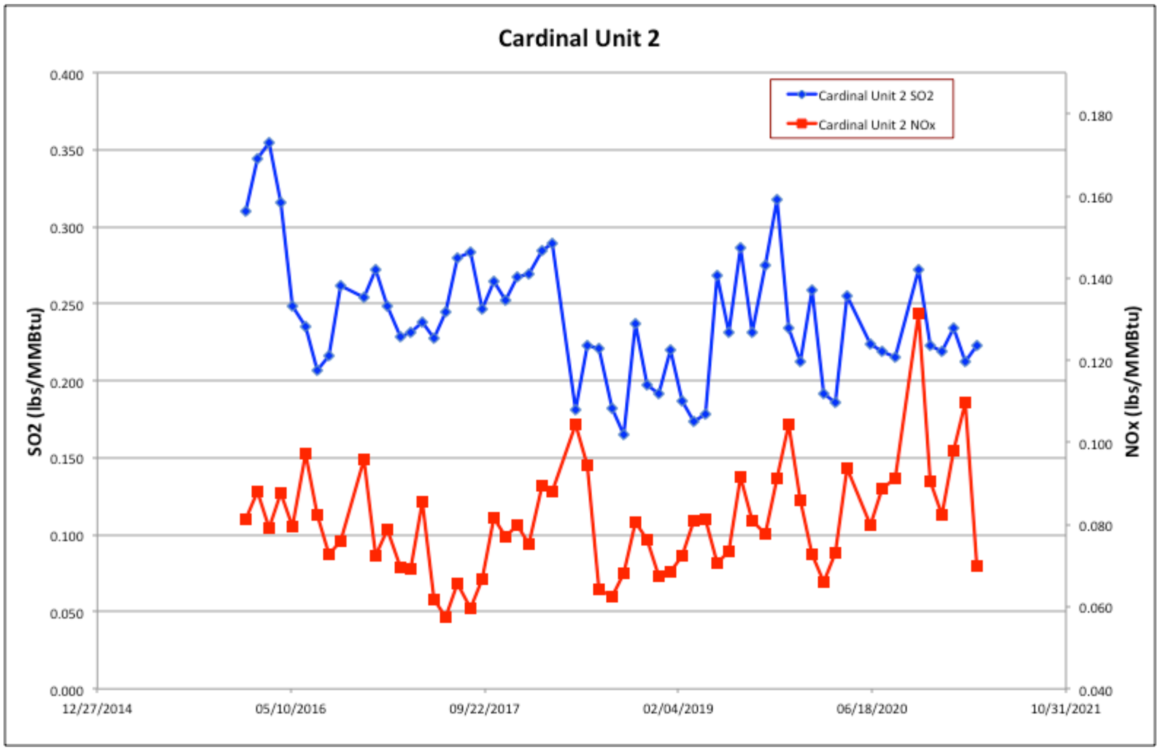
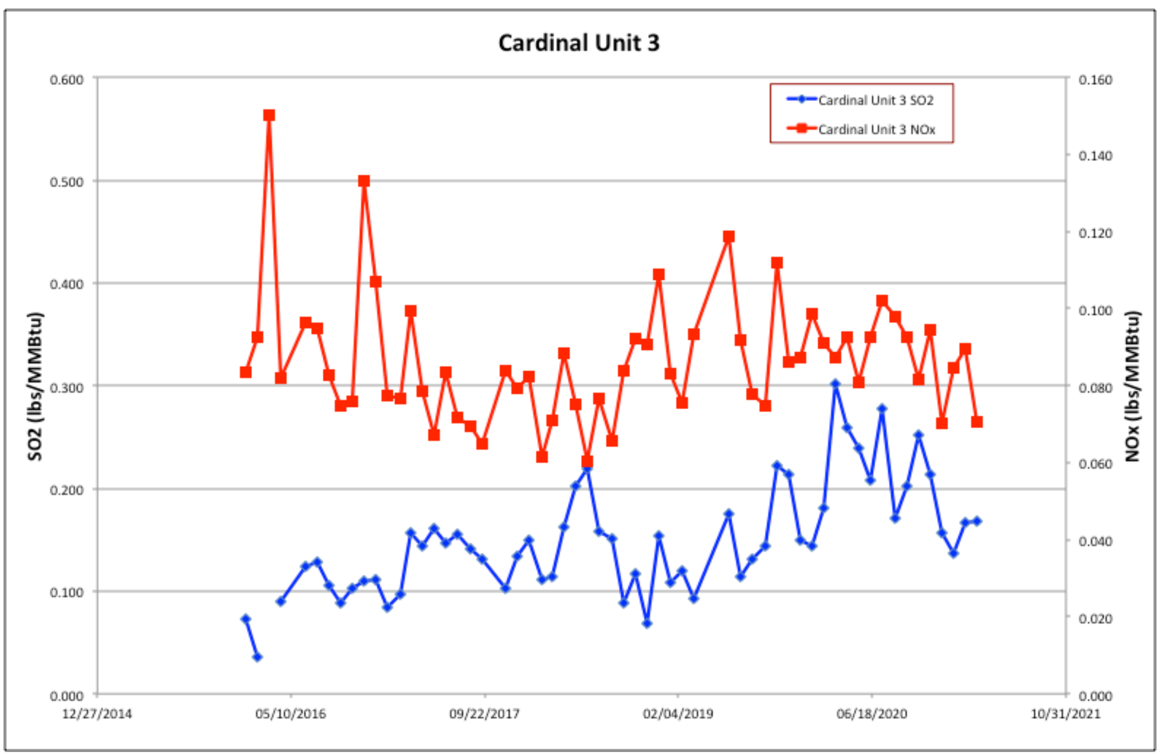


Figure 4. Cardinal Unit 3 Monthly Average SO_2 and NOx emissions.



4.3 It can be seen from the above graphs, that the monthly SO_2 emissions for the Cardinal units are fairly variable, which suggests that Cardinal's scrubbers can be further optimized.

4.4 Similar comments pertain to Ohio's assumptions regarding the performance of the Cardinal SCR systems. Ohio states that the same consent decree resulted in the installation of SCR systems on the three Cardinal units with efficiencies of approximately 90%.[24] Again, the consent decree does not appear to specify any actual NOx emission limits or SCR efficiencies for those units. In addition, Cardinal's Title V permit does not appear to specify any NOx emission limits for the units that would approach 90% control.[25]

SCR systems can often be upgraded very cost-effectively by selecting catalyst that is better optimized to the SCR inlet temperature, optimizing the ammonia injection system to improve the ammonia mixing and distribution, optimizing catalyst rejuvenation/regeneration, or simply using more reagent. As the Control Cost Manual states, [26]

> 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 [Flue Gas Recirculation] 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).

Thus retrofit SCR systems for coal-fired EGUs can typically be relied upon to achieve at least 90% control with a floor of 0.04 lbs/MMBtu. In some cases, coal-fired EGU SCR systems can continuously achieve less than 0.04 lbs/MMBtu on a 30 day rolling average basis.

4.5 It appears from the above graphs that the performance of Cardinal's SCR systems is suboptimal, with recent monthly NOx averages typically ranging from 0.06 – 0.12 lbs/MMBtu. As indicated above, the performance floor for coal-fired EGUs is at least 0.04 lbs/MMBtu, if not lower. In fact, Cardinal Unit 1 formerly had one of the best performing SCR units in the U.S., as the following graphs indicate:

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[24] See page 28.
[25] FINAL Division of Air Pollution Control Title V Permit for Cardinal Power Plant (Cardinal Operating Company), Facility ID: 0641050002, Permit Number: P0089700, Permit Type: Renewal, Issued: 01/07/2021, Effective: 01/28/2021, Expiration: 01/28/2026, *available at* FILL IN.
[26] Control Cost Manual, Chapter 2 Selective Catalytic Reduction, June 2019. See pdf page 5.

Figure 5. Cardinal Unit 1 Historical 30 BOD NOx Performance

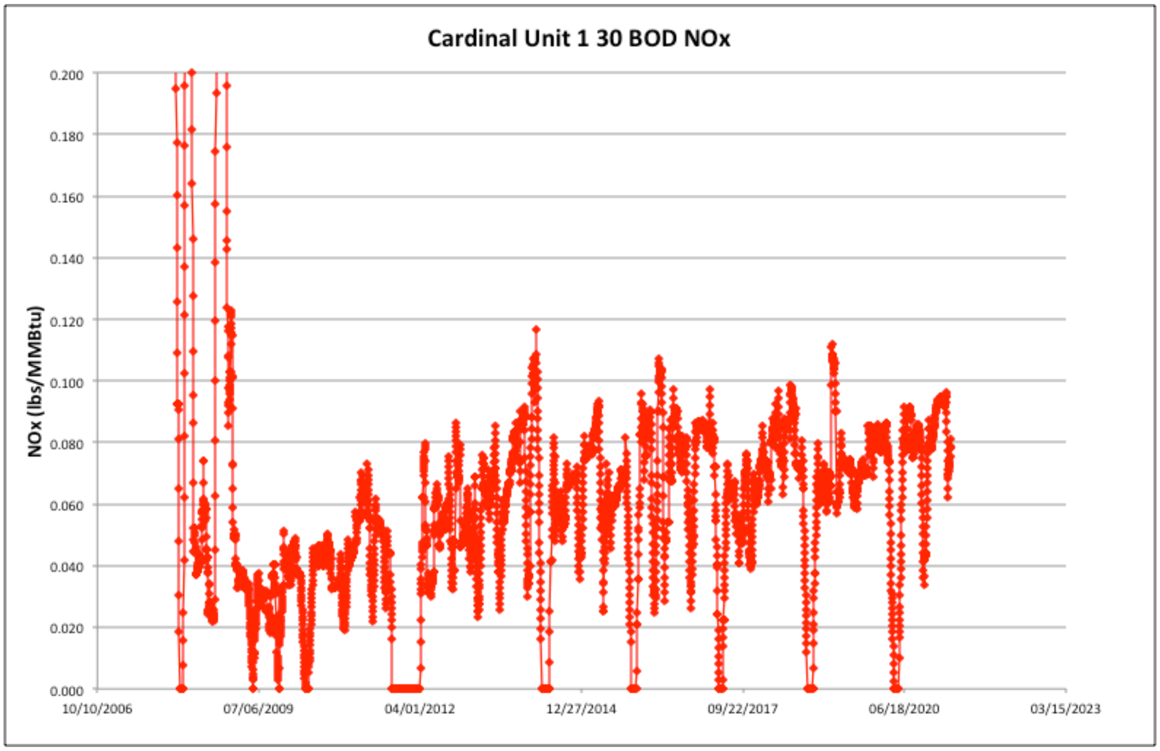
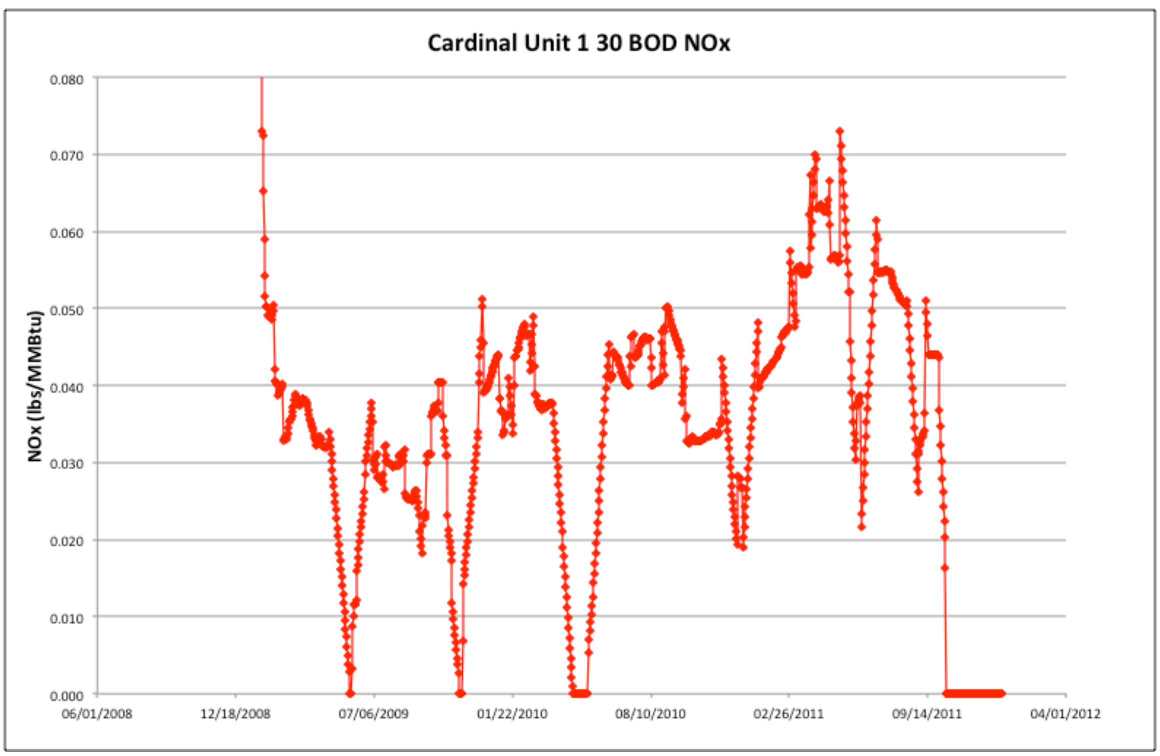


Figure 6. Cardinal Unit 1 Selected Historical 30 BOD NOx Performance



The above figures illustrate the Cardinal Unit 1 SCR system performance during two different time intervals. The NOx emissions are plotted based on a 30 BOD average.[27] As can be seen from Figure 4, the Cardinal Unit 1's SCR performance has gradually worsened over time. Figure 5 illustrates the SCR performance for the first two years after it was first installed. As can be seen, the SCR system is capable of sustained performance under 0.04 lbs/MMBtu. An examination of Cardinal Units 2 and 3 SCR systems reveals similar capabilities. In fact, the performance of the Cardinal Units' SCR systems was formerly so good that EPA included it in its survey of the best coal-fired EGU SCR systems to support its New Mexico FIP, which concluded that SCR systems for the San Juan Generating Station were not only cost-effective, but should be required to meet a NOx rate of 0.50 on a 30 BOD average.[28] It appears that the only thing preventing the Cardinal units from achieving this level of SCR performance again is the lack of an enforceable NOx limit requiring it. Consequently, Ohio should require that a four-factor NOx analysis be performed, as it appears likely that additional NOx reductions could be achieved very cost-effectively.

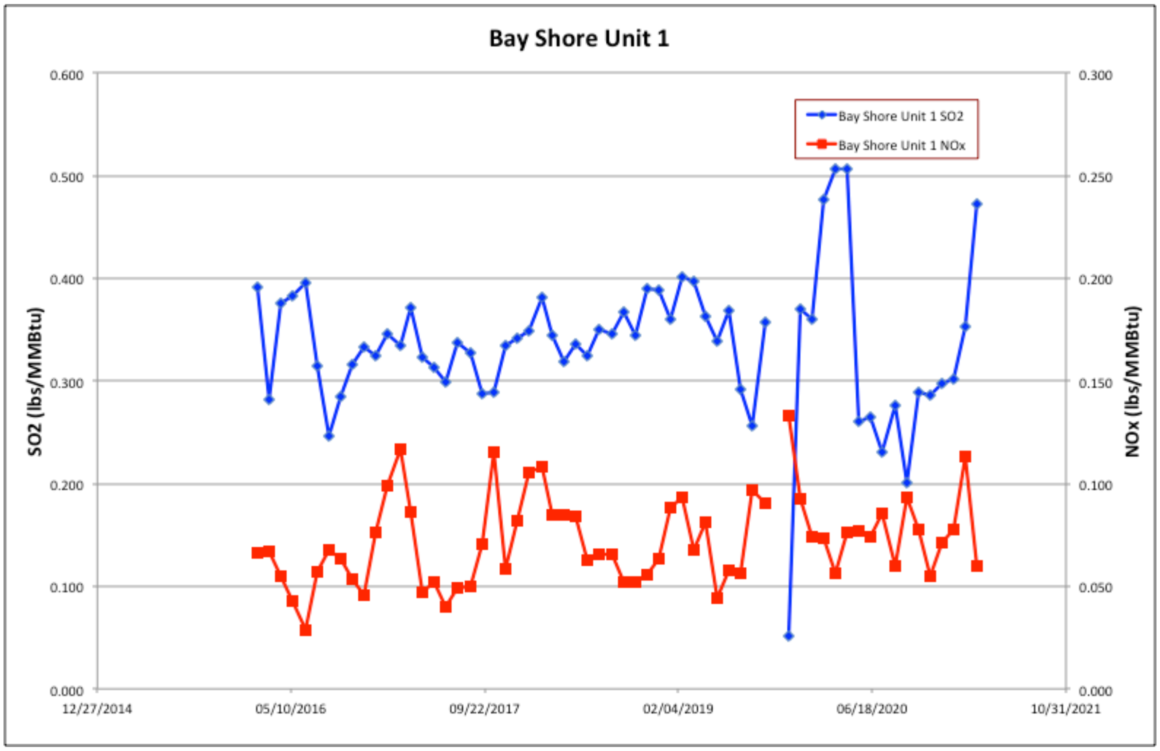
5 Discussion of the Bay Shore Facility

On page 30, Ohio discusses the emissions of the Bay Shore Unit B006 (Unit 1). Similar to its discussion of the Cardinal units, Ohio states that it has a SO_2 limit of 0.73 lb/MMBtu on a 30-day rolling average basis and is required to meet 90% reduction of SO_2 (except that 70% reduction is allowable for all heat inputs less than 0.60 lb SO_2 /MMBtu). It also has a NOx limit of 0.20 lb/MMBtu on a 30-day rolling average basis. Ohio points to annual SO_2 emissions of 0.32 – 0.34 lbs/MMBtu and annual NOx emissions of 0.06 – 0.08 lbs/MMBtu. As with the Cardinal units, an examination of the monthly emissions provides more detail:

[27] Emissions were downloaded from https://ampd.epa.gov/ampd/. EGU emission limits based on rolling 30 BOD averages are preferred over those conditioned based on 30 day running averages because they de-emphasize emission spikes that occur when units are started, shut down, or malfunction. This results from only counting the days when the unit operates in the averaging. Note that EPA states that EGUs should in fact be conditioned on rolling 30 BOD averages in the BART Final Rule (70 FR 39172).

[28] See EPA's proposal at 76 FR 491 (January 11, 2011) and its final at 76 FR 52388 (August 22, 2011). In particular, see the discussion at 76 FR 52404: "The Havana Unit 9 data shows that it has operated under 0.05 lbs/MMBtu from mid-2009 to the end of 2010 on a continuous basis. In fact, this unit has operated under 0.035 lbs/MMBtu for much of that time. The Parish Unit 7 data shows that it has operated under 0.05 lbs/MMBtu from mid-2006 to mid 2010 on a continuous basis. In fact, this unit has operated for months at approximately 0.035 lbs/MMBtu, and for approximately 2 years at approximately 0.04 lbs/MMBtu. The Parish Unit 8 data show that it has operated almost continuously under 0.045 lbs/MMBtu since the beginning of 2006. Other units' data show months of continuous operation below 0.05 lbs/ MMBtu. We believe this data demonstrates that similar coal fired units that have been retrofitted with SCRs are capable of achieving NOx emission limits of 0.05 lbs/MMBtu on a continuous basis." Also see this document in which the SCR performance of the Cardinal and other top performing SCR systems discussed above was graphed: https://www.regulations.gov/document/EPA-R06-OAR-2010-0846-0129.

Figure 7. Bay Shore Unit 1 Monthly Average SO_2 and NOx emissions



As with the Cardinal units, Bay Shore has been operating considerably below its permitted 30-day SO_2 limit of 0.73 lbs/MMBtu. Also similar to the Cardinal units, Bay Shore cannot meet its MATS SO_2 limit (0.3 lbs/MMBtu when burning pet coke) and so presumably satisfies MATS by alternatively meeting an HCl limit. Therefore, the permit SO_2 limits for the Bay Shore Unit 1, do not guarantee future performance. In fact, as can be see from the above graph, there are significant recent excursions from Bay Shore's better historical SO_2 control. This indicates that Bay Shore's permitted SO_2 rates should be tightened. In addition, there are instances in which the monthly SO_2 emission rate has averaged 0.25 lbs/MMBtu or less. Assuming a relatively stable coke sulfur content, this would indicate additional SO_2 control could be brought to bear. Lastly, there is no technical reason why post combustion controls such as DSI cannot be installed on a CFB boiler such as Bay Shore Unit 1. This would likely result in significant additional SO_2 reductions. For these reasons, Ohio should require that Bay Shore perform a four-factor analysis.

In summary, the fact that an EGU is equipped with the most effective control *technology* (e.g., scrubbers and/or SCRs) does not mean those controls are operating at their most effective levels. In every case, Ohio should investigate whether upgrades to these controls would be cost-effective. Furthermore, the above comments concerning the performance level of wet scrubbers and SCR systems notwithstanding, any performance level that Ohio uses to determine that a control should not be further optimized should be secured with an enforceable instrument in its SIP.

6 Review of the Gavin Four Factor Analysis

The Gavin SO_2 four factor analysis, covering Units 1 and 2, was reviewed.[29] In addition, a supplemental NOx report was also reviewed.[30] No control cost analyses were included in either report, as Ohio relies on Gavin's assertion that the existing wet scrubbing and SCR systems have been upgraded as much as possible.

6.1 Ohio Should Revise the Gavin SO_2 and NOx Limits. As Ohio notes on page 31 of its SIP, the only SO_2 limitation Ohio has placed on the Gavin units is that SO_2 emissions cannot exceed 7.41 lbs/MMBtu.[31] As with the Cardinal and Bay Shore units, Gavin does not meet the MATS SO_2 limit of 0.2 lbs/MMBtu, and so presumably satisfies MATS by alternatively meeting a HCL limit. Therefore, the permit SO_2 limits for Gavin Units 1 and 2 do not guarantee Gavin's compliance with an achievable, cost-effective SO_2 emission limit necessary to make reasonable progress.

6.2 Ohio Should Require a Four-Factor Analysis for SO_2 and NOx. Gavin's 19 page SO_2 four-factor report's main point was that it has exhausted all possibilities for further upgrading its scrubbers. On page 6, Gavin states that it upgraded its wet scrubbers in May 2019 to use limestone instead of magnesium-lime as a reagent. Gavin also states that two new trays were installed in each of its six absorbers, new recycle pumps were installed, recycle pump motors were (as of the March 2021 date of the report) in the process of being upgraded, and an additive is used to add buffering to the recycle slurry. Gavin states these improvements increased the Liquid/Gas (L/G) ratio from 21-32 to 56. Once the recycle pumps are upgraded, it expects the recycle pump rate to further increase, resulting in an even higher L/G ratio.[32] Gavin states that with these improvements, its wet scrubber systems have been operating at just above 95% control efficiency since the improvements were completed in mid-2020. Below is a graph of the Gavin Unit 1 and Unit 2 SO_2 and NOx emissions before and after these improvements:

[29] SO_2 Four Factor Analysis Regional Haze Rule Second Decadal Review, General James M. Gavin Power Plant Units 1 and 2, AECOM Project Number: 60645830, Revision 1: March 31, 2021.

[30] Appendix L, Regional Haze SIP – Second Implementation Period Response To FLM Comments, Attachment 2 Supplemental Information Provided By Gavin Power Plant Page 1, Gavin Power Plant Current NOx Emissions and Haze Impacts May 4, 2021.

[31] This limit is so high, that if Unit 1 actually met this limit at its 2019 heat rate, it would be by far the most polluting EGU in the U.S., emitting more than 269,000 tons of SO_2: 72,700,693.5 MMBtu x 7.41lbs/MMbtu x 1.0 ton/2,000lbs = 269,356 tons.

[32] Although this is an improvement in the L/G ratio, it appears there is considerable room for additional improvement. See https://www.powermag.com/scrubbing-optimizing-flue-gas-desulfurization-technologies-is-essential/: "A not uncommon L/G ratio is around 120 gallons per minute (gpm) liquid flow per 1,000 actual cubic feet per minute (acfm) gas flow."

Figure 8. Gavin Unit 1 30 BOD SO_2 and NOx Average Emission Rates

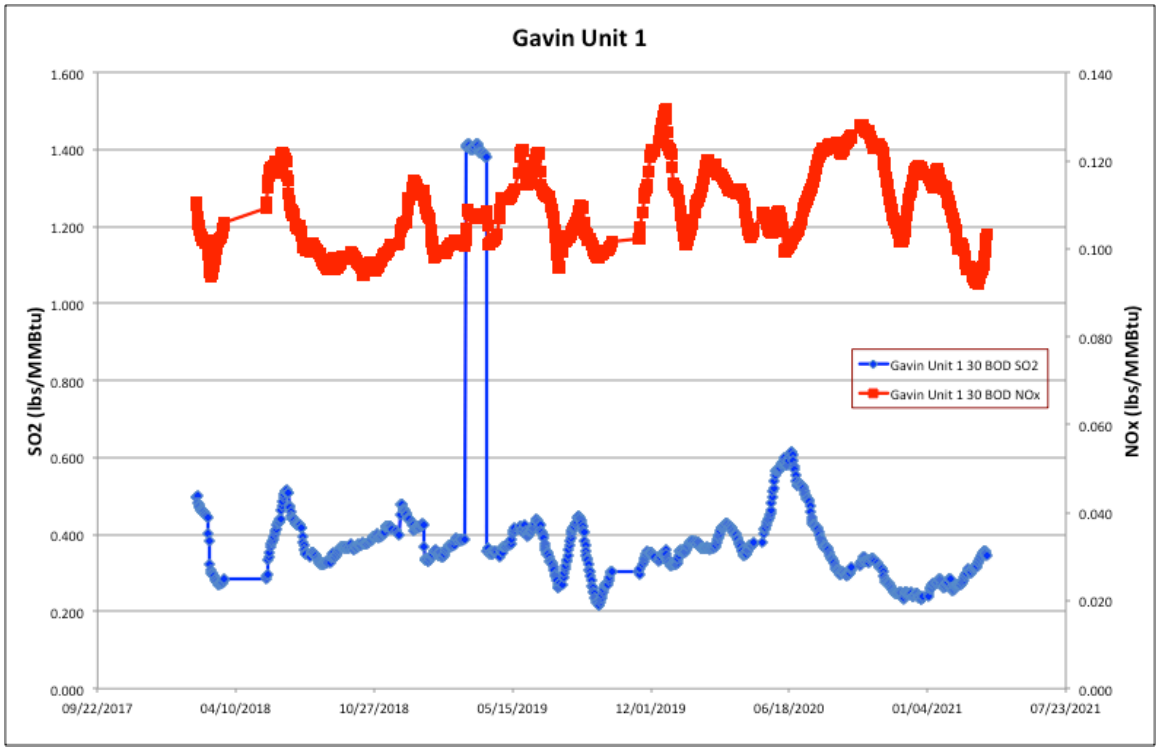
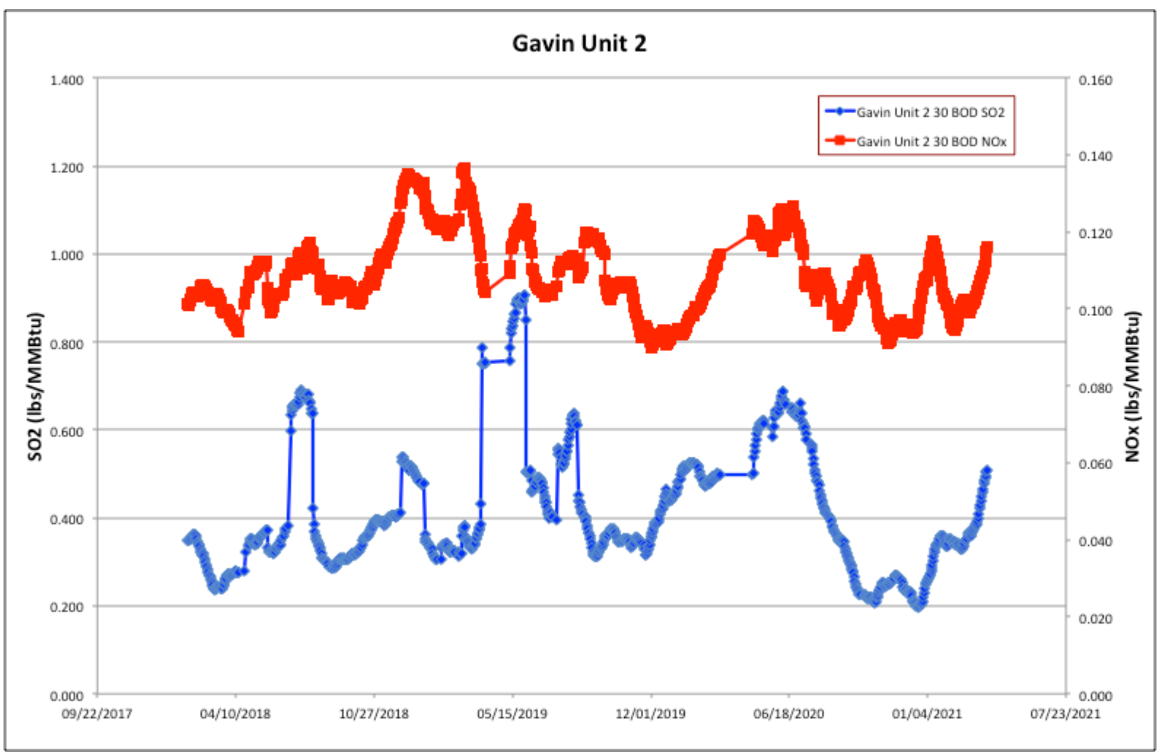


Figure 9. Gavin Unit 2 30 BOD SO_2 and NOx Average Emission Rates



As the above graphs illustrate, the Gavin SO_2 removal performance is fairly erratic, ranging from approximately 0.2 – 0.6 lbs/MMBtu for both units. There does not seem to be any indication of a clear performance improvement following the mid-2020 scrubber improvements that Gavin describes. This may in part be due to variability in the coal Gavin burns, which the EIA reports as "refined coal." Below is the sulfur content of the coal Gavin reported to the Energy Information Agency (EIA) for 2020:[33]

Table 1. Gavin Refined Coal Sulfur Content

Month	Sulfur Content (% by weight)
Jan	3.99
Feb	3.84
March	4.17
April	3.96
May	3.98
June	4.06
July	4.11
Aug	4.27
Sept	4.16
Oct	4.27
Nov	3.95
Dec	3.51

However, on page 5, Gavin states that the uncontrolled SO_2 emission rate for this coal typically ranges from 6.2 lb/MMBtu to 6.7 lb/MMBtu. Assuming Gavin's claimed 95% control, this would place the SO_2 emission rate at 0.31 – 0.34 lbs/MMBtu. Based on the above graphs of Gavin's 30 BOD SO_2 rates, it appears that Gavin frequently misses this level of control. Consequently, Ohio should require a SO_2 four-factor analysis for the Gavin Units.

6.3 Like the Cardinal Units, the Gavin SCR systems have historically performed better than they have done recently. Below are the historical rolling 30 Day NOx graphs for Units 1 and 2[34]:

[33] See the file, "OH EIA Fuel Data.xlsx." It appears there is an onsite processing plant that supplies "refined coal" to Gavin.

[34] Note that 30 BOD averages are not used here, because by definition they discard days when the boiler is not running, and so the outages are better shown with straight 30 day rolling averages.

Figure 10. Gavin Unit 1 Historical Rolling 30 Day NOx Performance

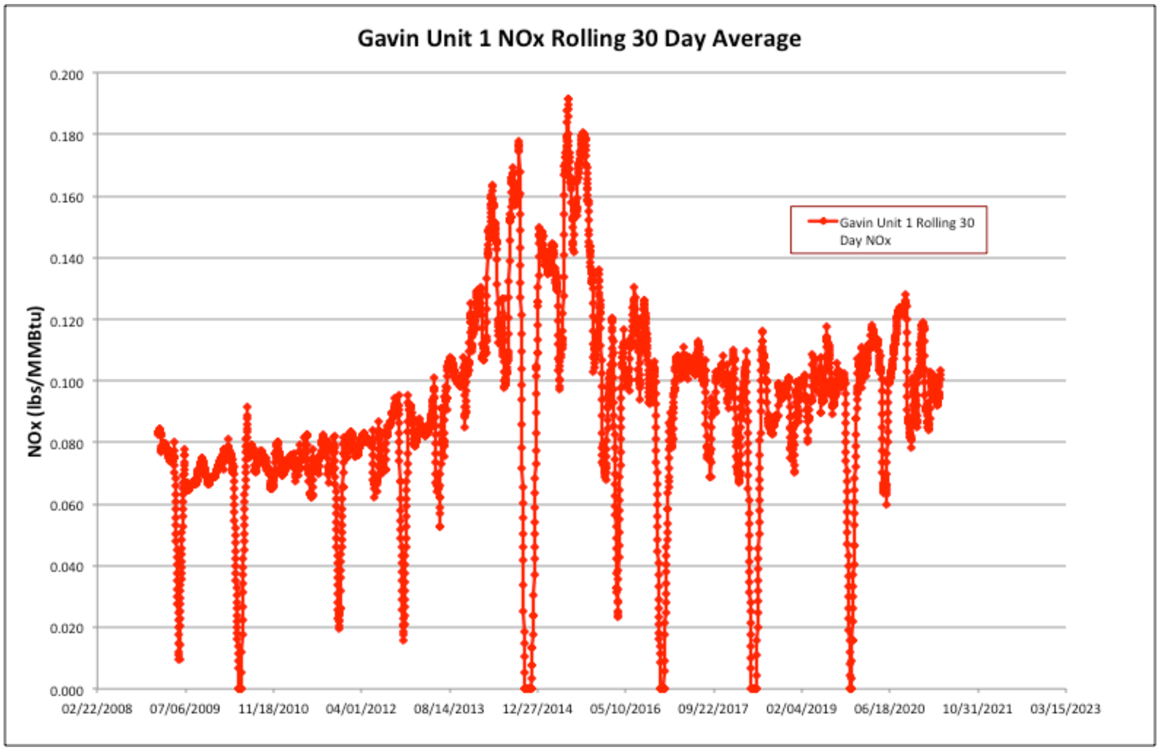
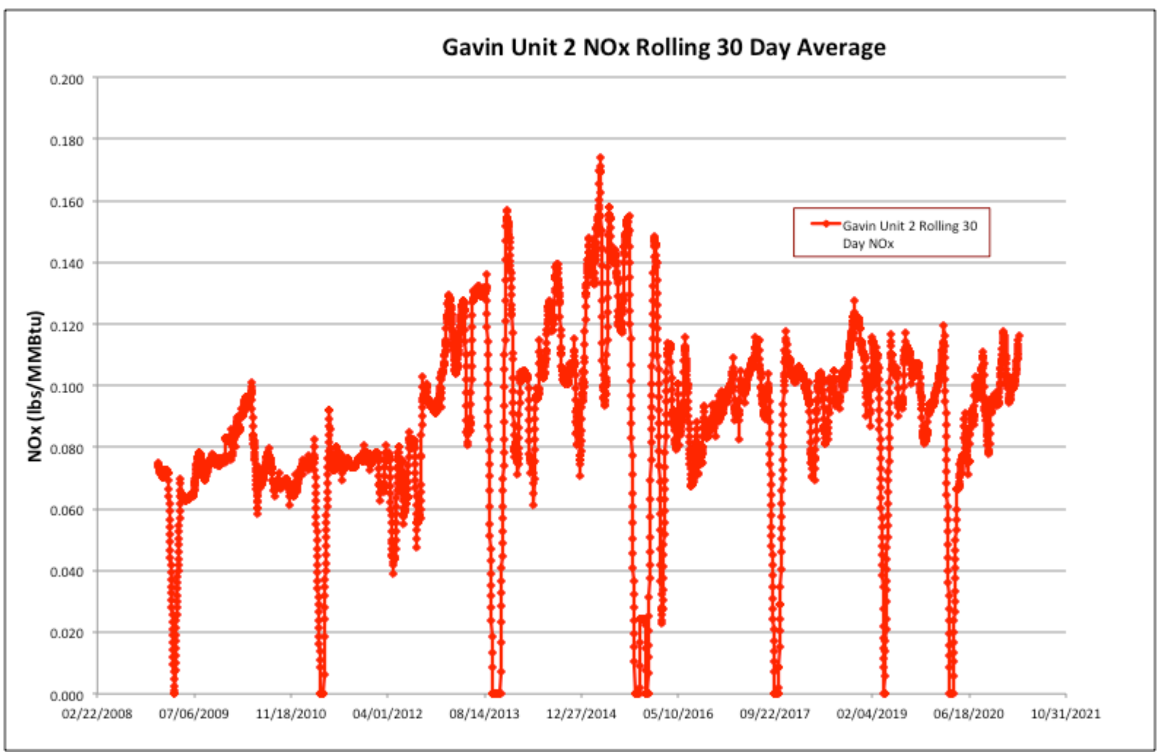


Figure 11. Gavin Unit 2 Historical NOx Performance



As can be seen from the above graphs, the SCR systems for both the Gavin units performed significantly better during the time period from at least January1, 2009 to July, 2012 – a period of at least 3-1/2 years. Regarding this, Gavin states on page 4 of Attachment 2 to Appendix L:

> As noted previously, in the 2009 to 2012 time period, the prior owner/operator of the Gavin Power Plant attempted to lower NOx emissions by injecting more ammonia. That effort was ultimately abandoned because of recurring issues with high ammonia slip that decreased mercury control levels and caused air heater pluggage. Indeed, the pluggage issues were so significant that they required repeated major plant outages to clean the air heater. During the 2009 to 2012 period, these air heater washes were required, at a minimum, twice a year – as well as more limited cleaning occurring every time there was any forced outage, no matter how short.

Essentially, the constraints Gavin mentions all involve operational and maintenance issues. But these issues are not unusual and have been routinely addressed by SCR system operators for decades. Operational and maintenance issues, along with the cost of additional ammonia, are regularly considered as part of control cost analyses and so can be easily monetized and rolled into a cost-effectiveness calculation. The fact remains that Gavin successfully operated its SCR systems with significantly improved performance for at least 3-1/2 years.

In an apparent attempt to tie these operational and maintenance issues to technical feasibility, Gavin states that the issues "were so significant that they required repeated major plant outages." However, it appears from the interruptions shown in the emissions data (when the data goes to zero) that the outages during the 2009-2012 timeframe occurred at approximately the same frequency as the time period following 2012, when Gavin states the practice of injecting additional ammonia ceased. Therefore, it does not appear that operating Gavin's SCR systems at a higher performance level resulted in a technical infeasibility issue, but rather a cost issue, which again is easily considered in a cost-effectiveness calculation.

6.4 Gavin also cites to concerns that higher levels of ammonia will reduce mercury oxidation, returning it to its elemental state, and thus adversely affect the ability of the wet FGD system to capture and control the mercury, potentially jeopardizing MATS compliance. If this indeed a real concern, then Gavin should demonstrate it as such. Optionally, Gavin can investigate methods of improving the ammonia injection, mixing and distribution system to minimize ammonia slip while maximizing SCR performance. In any case, it does not appear that Gavin has any active mercury controls, electing to depend on its scrubber and SCR system to remove mercury. Many coal-fired EGUs employ Activated Carbon Injection (ACI) to control mercury, and if necessary, so can Gavin. Any additional costs to install such a system as part of SCR optimization, if demonstrated to be necessary, can be rolled into a cost-effectiveness analysis.

Lastly, it appears that the Gavin SCR systems may not be running consistently, as there are many periods of much better SCR performance than others. As Ohio notes on page 31 of its SIP, Gavin's "Title V permit defines "continuously operated" as

> [W]hen an SCR, FGD, DSI, ESP or other NOx pollution controls are used at an emissions unit, except during a malfunction, they shall be operated at all times such emissions unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the emissions unit so as to minimize emissions to the greatest extent practicable.

This language was carried over from Gavin's consent decree. Considering this, Ohio may wish to examine if these SCR systems have indeed been run according to this requirement. In any case, Ohio should require a NOx four-factor analysis for the Gavin units.

7 Discussion of Review of the Kyger Creek Facility

This review included the material Ohio presents beginning on page 35 of its SIP and the additional material it cites to in Appendix L4, Attachment 1. Ohio declined to require a four-factor analysis for any of the five Kyger Creek units, concluding that the existing scrubbers and SCR systems were operating well enough that they could be considered "effectively controlled." As Kyger Creek indicates on page 2 of Appendix L4, Attachment 1, Units 1 and 2 share a scrubber and CEMS and Units 3, 4, and 5 share a scrubber and CEMS. Thus, the monitoring data available from EPA's AMPD website is apportioned and cannot be thought of as being particular to each unit. Analysis indicates that the NOx and SO_2 data for Units 1 and 2 are very similar and that for Units 3, 4, and 5 are very similar. Therefore, only monitoring data for Units 1 and 3 are referenced below:

Figure 12. Kyger Creek Unit 1 Recent NOx and SO_2 Monthly Emissions

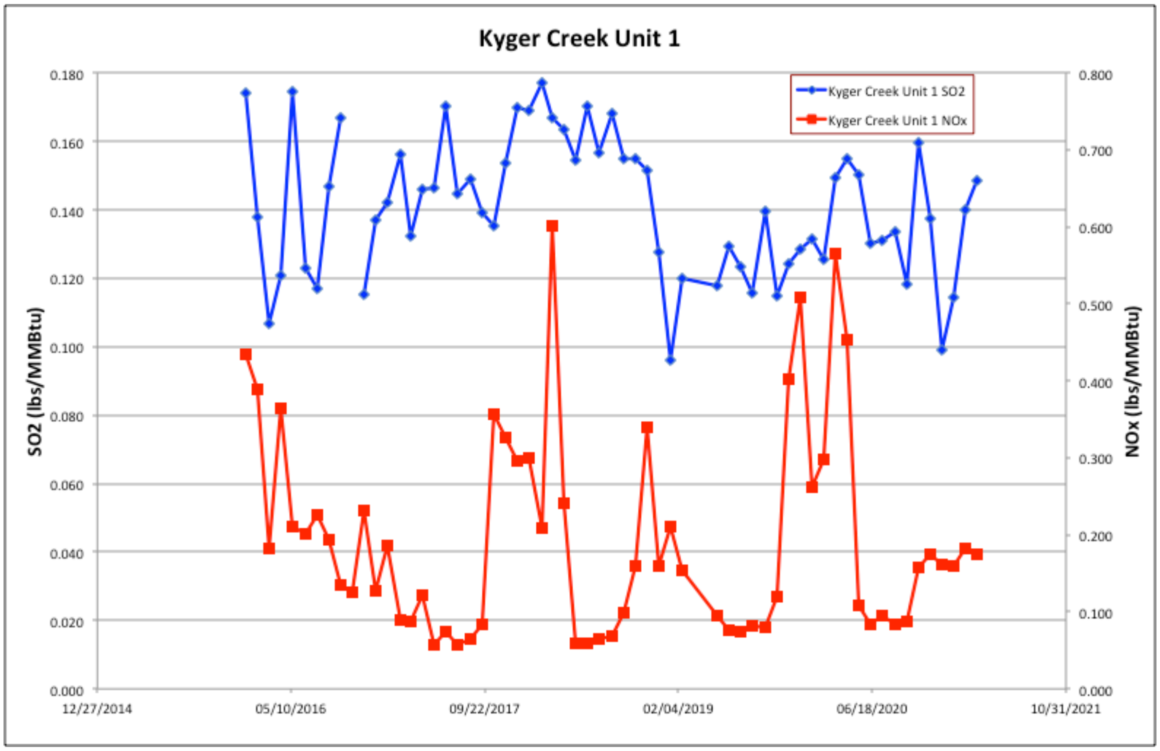
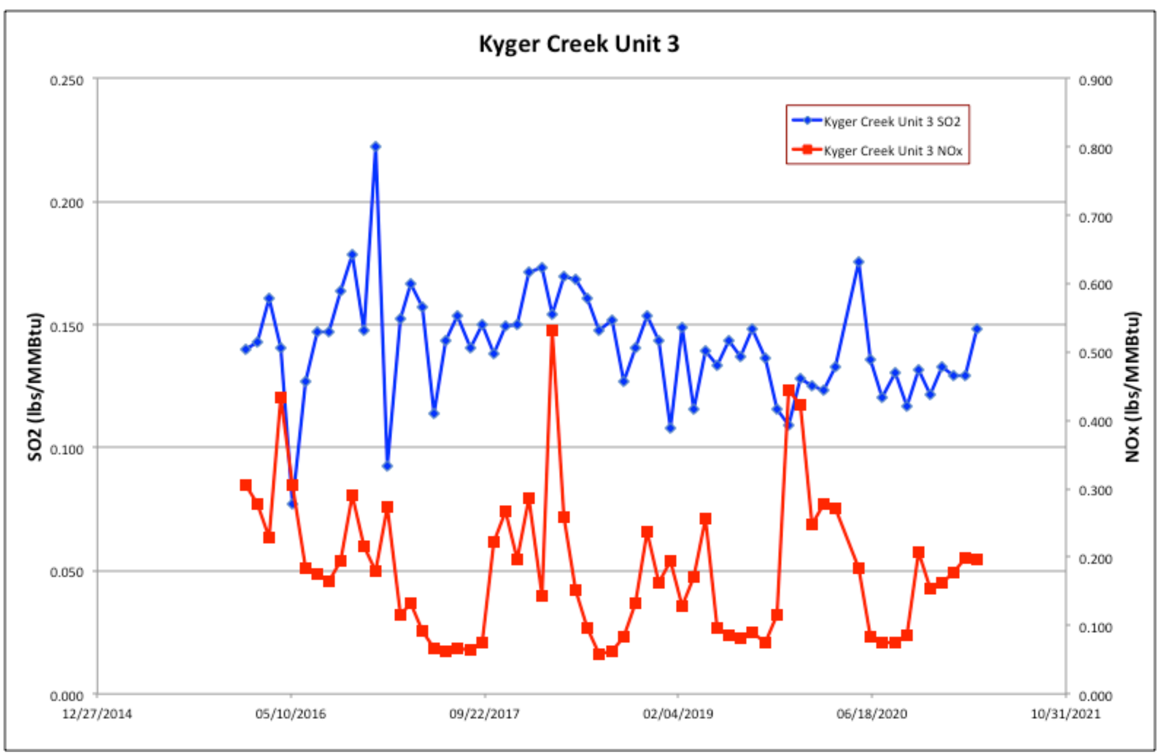
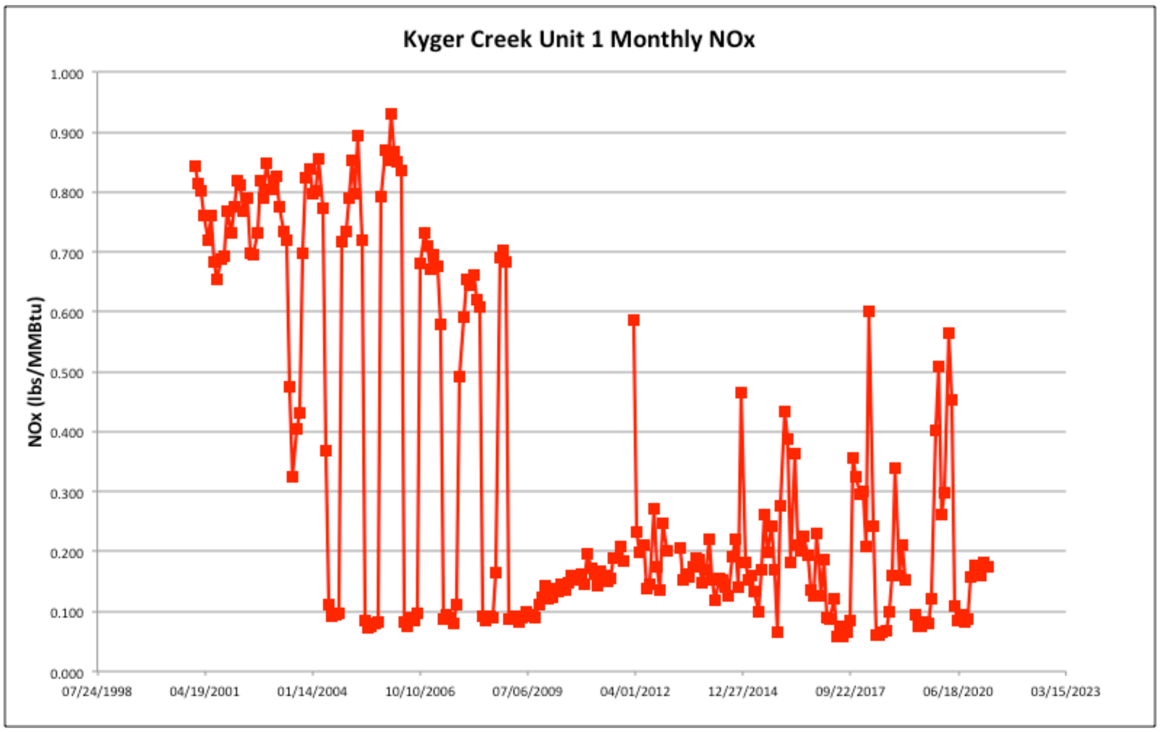


Figure 13. Kyger Creek Unit 3 Recent NOx and SO_2 Monthly Emissions



As can be seen from the above graphs, the performance of the Kyger Creek SCR systems alternates between 3-4 month periods of good NOx removal (approximately 0.06 – 0.08 lbs/MMBtu) with the rest of the time consisting of poor NOx removal. On page 35 of its SIP, Ohio states that Kyger Creek operates its SCR systems year round. However, it seems evident the facility only utilizes its SCR systems at their full capabilities during ozone season. This indicates that the true current performance potential of the Kyger Creek SCR systems is likely at least 0.06 lbs/MMBtu. The pre-SCR NOx level of Unit 1 is shown below:

Figure 14. Kyger Creek Unit 1 Historical NOx Monthly Emissions



Averaging the monthly NOx rates prior to the SCR installation in May, 2003 yields the following:

Table 2. Kyger Creek Unit 1 Pre-SCR Average Monthly NOx Rates

Month	Year	Avg. NOx Rate (lb/MMBtu)
1	2001	0.843
2	2001	0.814
3	2001	0.802
4	2001	0.761
5	2001	0.719
6	2001	0.761
7	2001	0.684
8	2001	0.654
9	2001	0.687
10	2001	0.694
11	2001	0.768
12	2001	0.733
1	2002	0.775
2	2002	0.820
3	2002	0.811
4	2002	0.767
5	2002	0.790
6	2002	0.699
7	2002	0.694
8	2002	0.732
9	2002	0.819
10	2002	0.789
11	2002	0.849
12	2002	0.804
1	2003	0.820
2	2003	0.827
3	2003	0.775
4	2003	0.734
Avg. Monthly NOx		0.765

Therefore, assuming a relatively consistent coal nitrogen content, and a floor of 0.06 lbs/MMBtu, a gross approximation of the current SCR system performance is approximately 92%.[35] As with the Gavin units, Kyger Creek argues that further

[35] ((0.765-0..060)/0.765) x 100% = 92.16%. Note that Kyger Creek states on page 4 of Appendix L4, Attachment 1, "the baseline emission rate for Kyger Creek Station boilers prior to SCR installation as

optimizing the SCR units may result in reduced mercury control, potentially jeopardizing MATS compliance. This argument is flawed for the same reasons discussed above in the Gavin analysis. In addition, when the Kyger Creek SCR units do perform well, they do so for 3 – 4 months at a time. So it is evident that at least this level of performance would not jeopardize the Kyger Creek mercury MATS compliance, as such an issue would have already surfaced, since MATS compliance is figured on the basis of a 30 BOD average. Thus, it appears the only thing preventing the Kyger SCR units from consistently achieving this level of performance is the lack of an enforceable NOx limit requiring it. Ohio should therefore require that the Kyger Creek SCR systems undergo four-factor analyses. At a minimum simply running its SCR systems at full capacity all year round would likely be very cost-effective. Further SCR optimization may result in even more very cost-effective controls.

8 Discussion of the W H Sammis Facility

Ohio declined to require a four-factor analysis for any of the W H Sammis Creek units, concluding that the existing scrubber and SCR systems were operating well enough that they could be considered "effectively controlled." Ohio states that Sammis permanently shut down coal-fired boilers B007, B008, B009 and B010 (Units 1-4) on May 31, 2020. Ohio also states that FGDs with 95% control efficiency were installed February 10, 2010 on B012 and B013 (Units 6-7), and SCRs with at least 90% control efficiency were installed February 3, 2010 on B012 and April 24, 2010 on B013.

However, Ohio does not discuss B011 (Unit 5). According to the CD Ohio cites, by December 31, 2008, Unit 5 was required to have a Flash Dryer Absorber or equivalent with at least a 50% efficiency for SO_2. According to Ohio's Title V permit and EPA's AMPD data, this unit is fitted with a wet scrubber and SNCR system. Ohio should include this unit in its analysis.

8.1 According to information from Babcock and Wilcox Power,[36] three absorbers were installed, which provided enough scrubbing capacity for all seven units. Sammis' Title V permit indicates that all seven units were indeed scrubbed. Consequently, with four units now retired, it appears there is excess scrubbing capacity. However, it does not appear that the scrubber systems for Units 5-7 are being used to their full capacity, as the following graphs illustrate:

defined in 40 CFR Section 76.6, is an emission rate of 0.84 lb/mmBtu." Based on the emissions noted above, this appears too high.

[36] See https://www.babcock.com/-/media/documents/case-profiles/power/wh-sammis-plant-environmental-retrofits.ashx.

Figure 15. WH Sammis Unit 5 Recent NOx and SO_2 Monthly Emissions

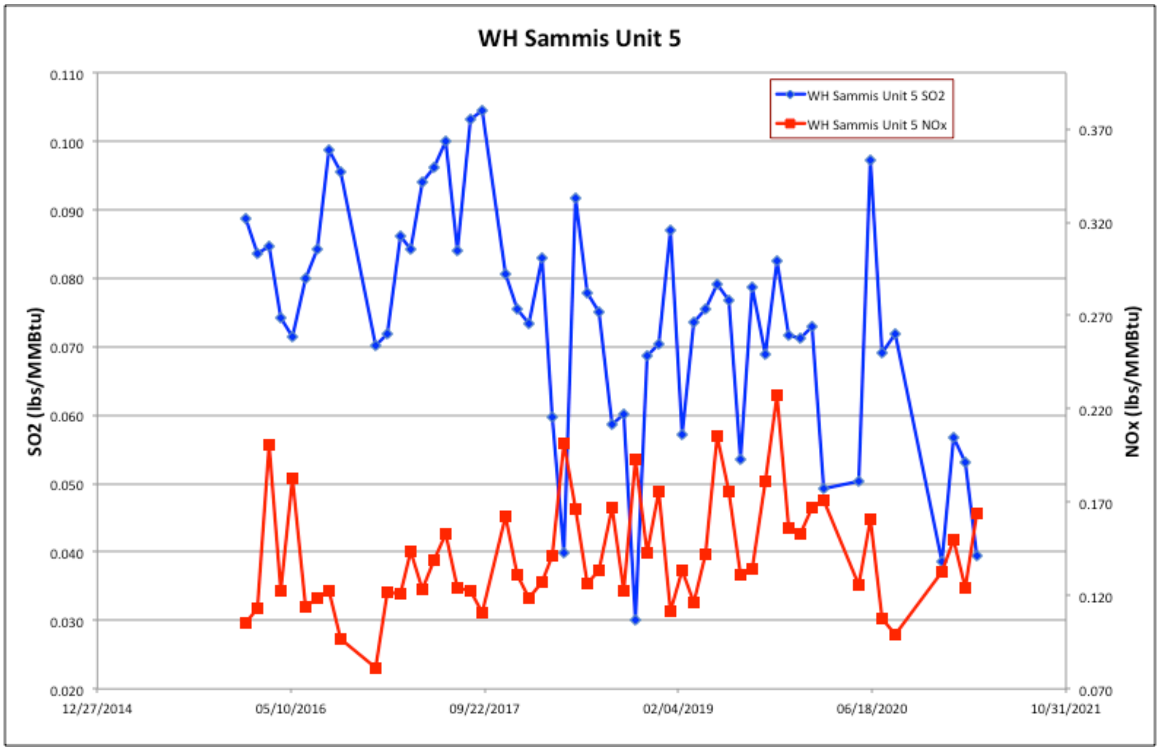


Figure 16. WH Sammis Unit 6 Recent NOx and SO_2 Monthly Emissions

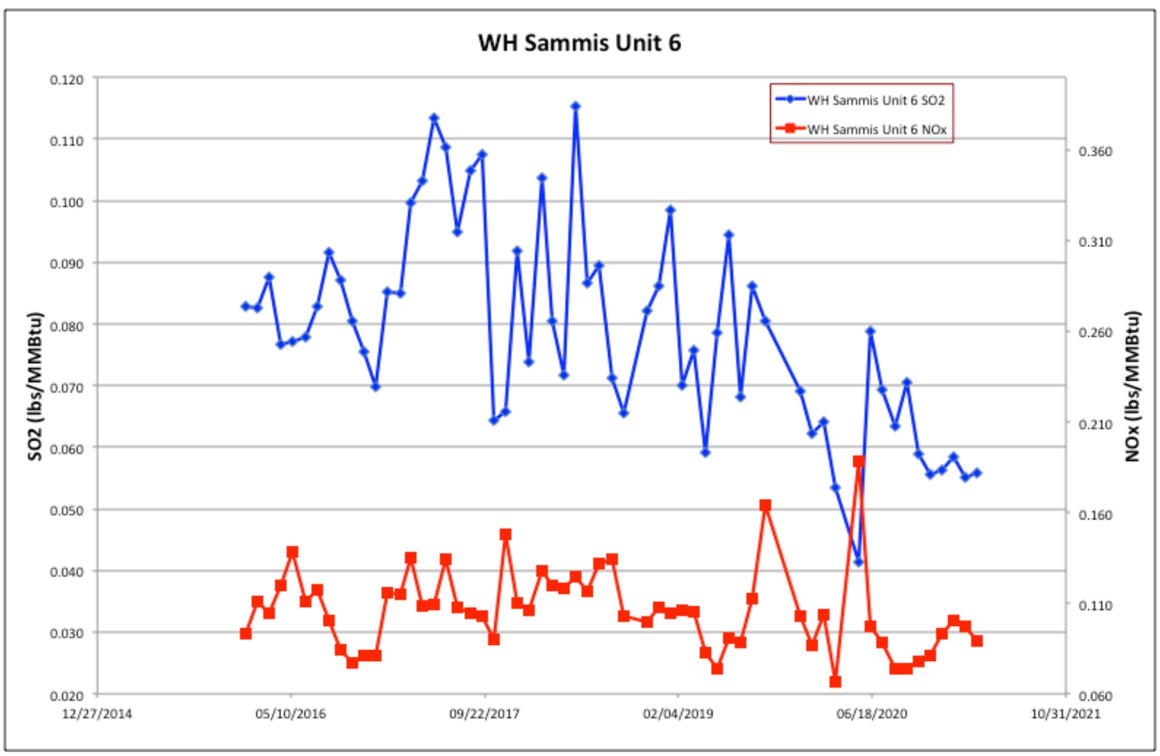
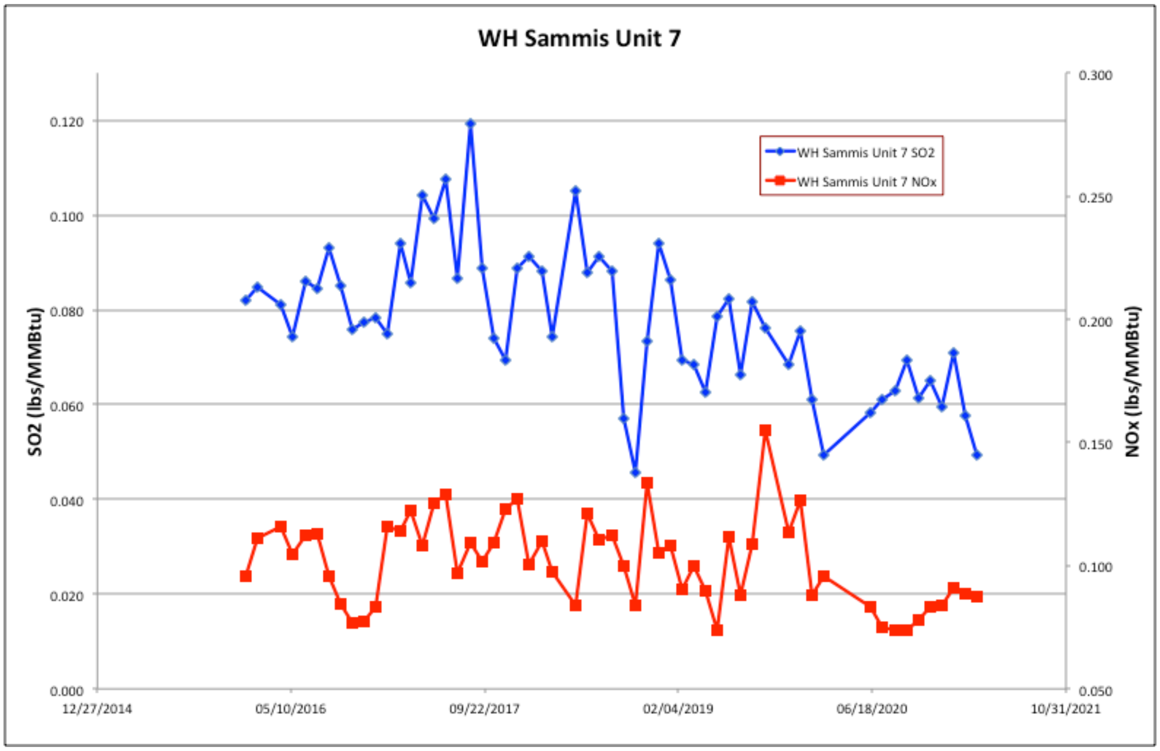


Figure 17. WH Sammis Unit 6 Recent NOx and SO_2 Monthly Emissions



Furthermore, as the above figures indicate, the scrubber performance of the three Sammis units is sporadic. Sammis' CD and its Title V require that Units 5, 6, and 7 meet a rolling 30 day emission limit of 0.13 lbs/MMBtu. As can be seen from the above graphs, all three units operate considerably under that limit most of the time. In fact, it appears the performance floor for the scrubber systems is at least 0.060 lbs/MMBtu. Considering the capacity of the scrubber systems and its newness, this is not unexpected.

Similarly, the SCR systems for Units 6 and 7 indicate that the performance floor is at least 0.07 lbs/MMBtu, as it appears the units regularly operate at those levels for 2-3 months at a time. Also, the SNCR system for Unit 5 appears capable of operating considerably below its CD and Title V rolling 30 day emission limit of 0.290 lbs/MMBtu. Therefore, Ohio should require a four-factor analysis for Units 5, 6, and 7 so that the performance of the scrubber, SCR, and SNCR systems can be optimized and their emission reductions secured. It is very likely that these improvements will prove to be very cost-effective.

9 Review of the Avon Lake Unit 9 Four-Factor Analysis

The Avon Lake Unit 9 four factor analysis was reviewed.[37] This unit's emissions are reported to EPA AMPD as "Unit 12" and so graphs and references in this section of Unit 9's emissions are depicted as "Unit 9 (12)."

[37] Four Factor Analysis Regional Haze Rule Second Decadal Review, Avon Lake Power Plant Unit 9/Boiler 12, AECOM Project Number: 60637173, Revision 4: April 6, 2021.

In several places Avon Lake mentions a 2009 URS study from which it quotes wet scrubber and SCR costs. It appears part of this study is in Appendix D. However, that study is missing all of its appendices, which include important details to the cost analyses, including the costs. Ohio should request this information, as it is important to the determination of reasonable progress for Avon Lake. It is assumed that if it is claimed as confidential, Ohio has procedures in place to properly review and house that material while providing the public with the information necessary to allow for meaningful review and comment.

9.1 On page 4 of its report, Avon Lake states that the existing DSI system, which uses the existing ESP, is designed to satisfy its HCl obligation under MATS and is therefore not designed to reduce SO_2. Avon Lake concludes that high sorbent injection rates required for any appreciable SO_2 control would exceed the capability of the existing ESP and therefore, implementing upgrades to the existing DSI system is not a practical control option. Avon Lake then states that a SDA or wet scrubber is required for achieving SO_2 reduction and does not further consider DSI. There does not appear to be any technical reason why a separate DSI system, designed for SO_2 removal, cannot be retrofitted to Avon Lake Unit 9. Such a system will likely require a baghouse. However, there are many EGUs that operate with ESPs and a baghouse, or a baghouse and an abandoned ESP. Such a system should be able to address Avon Lake's HCl MATS obligation and also substantially reduce SO_2. Therefore, Ohio should require that Avon Lake investigate this option for SO_2 control.

9.2 On page 4 of its report, Avon Lake states that it escalated a December 2009, URS Washington Group cost analysis, which estimated the total capital cost of a wet FGD system at $389 million, which if escalated to 2019 would result in a capital cost of $453 million.

9.3 On page 5 of its report, Avon Lake states that the site presents space constraints due to the DSI and ACI systems, which results in limited space available for installation of an SO_2 scrubbing system including a new wet stack. It presents a picture that is intended to depict that situation:

Figure 18. Avon Lake's Aerial Photograph of its Facility

9.4 Avon Lake also states there is inadequate space available for staging and assembly of equipment and that the fabrication and assembly would have to be done offsite and transported to the plant, which is a significant cost adder. As such, Avon Lake has states that a retrofit factor of 1.2 is appropriate in its SCR and scrubber cost estimates.[38]

However, the picture presented by Avon Lake does appear to depict all of the property under its control. The following is an aerial photograph of the site that indicates additional property to the South and East-Northeast:

[38] Avon Lake also provides cost estimates for SCR and scrubbers using a retrofit factor of 1.0.

Figure 19. Google Earth Aerial Photograph of the Avon Lake Facility

As can be seen from the above picture, it appears there is a great deal more room for staging and assembly of equipment, including additional space in a parking lot that is not being used. In fact, some of this additional area was identified by URS for use in its 2009 SCR and scrubber cost analyses.[39] Furthermore, it is not unusual for similar facilities, including those in Ohio, to construct very large pieces of control equipment offsite, including absorbers, and transport them to the site.[40] Although this is not a BART determination, Ohio has referenced other aspects of the BART Rule, and it is believed that BART Guidance is generally instructive: in this case, the BART Guidelines require that "documentation" be provided for "any unusual circumstances that exist for the source that would lead to cost-effectiveness estimates that would exceed that for recent retrofits."[41] Thus, it does not appear that Avon Lake has adequately documented its need for a retrofit factor of 1.2. A retrofit factor is a direct multiplier to the capital costs. Therefore, a retrofit factor other than 1.0, which covers average difficulty retrofits, should be very well documented.

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[39] FGD And SCR Retrofit Budgetary Cost Estimate & Schedule, Project Number 27709-269 Avon Lake Station – Unit 9, Volume 1, Prepared For RRI Energy, Inc. December 2009. See Appendix D of Avon Lake's report, pdf page 146.

[40] This was the situation for the WH Sammis facility, which installed a wet scrubbing system that serviced all seven units and was much larger in scope: https://www.babcock.com/-/media/documents/case-profiles/power/wh-sammis-plant-environmental-retrofits.ashx.

[41] See 70 FR 39168 (July 6, 2005).

9.5 On page 6 of its report, Avon Lake states that it incorporated Allowance for Funds Used During Construction (AFUDC) because the Control Cost Manual, Chapter 2, Page 11 notes that AFUDC is considered a cost item within the electric power industry. Avon Lake also includes owner's costs in its emission control cost estimates in Appendix B. Avon Lake misunderstands the Control Cost Manual's position on AFUDC. It is correct that the Control Cost Manual notes that AFUDC is used in the electric power industry. However, it is not used in the Control Cost Manual's "overnight" cost calculation methodology. In fact, the Control Cost Manual states "owner's costs and AFUDC costs are capital cost items that are not included in the EPA Control Cost Manual methodology, and thus are not included in the total capital investment (TCI) estimates in this section."[42] Therefore, Ohio should require that these cost items be removed from all control cost analyses.

9.6 On page 6 of its report, Avon Lake states that it based its capital recovery costs on a 7% interest rate and 20-year equipment life. Avon Lake states that the Control Cost Manual states that "[t]he Control Cost Manual notes that the bank prime rate can be used as an indicator of interest rate when a firm-specific interest rate is not available. However, EPA cautions that the bank prime rates do not adequately account for project-specific risks including the length of the project and the credit risks of the borrowers." Avon Lake also states that the Office of Management and Budget (OMB) uses an interest rate of 7%, citing OMB Circular A-4: [43]

> As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.

Avon Lake misunderstands the Control Cost Manual's position on the OMB Circular to which it cites. In fact, the Control Cost Manual states the following: [44]

> As stated earlier, interest rate accounts for the time value of money, inflation, and other premiums, including risks, faced by lenders. The social discount rate is the rate at which society can trade consumption through time (i.e., the time value of money). When assessing the societal effect of regulations, such as for EPA rulemakings that are economically significant according to Executive Order 12866, analysts should use the 3% and 7% real discount rates as specified in the U.S. Office of Management and

[42] Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, June 2019, pdf page 65. Also see Section 5, SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021, page 1-49.
[43] See page 7 of Avon Lake's report.
[44] See Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, November 2017, page 16.

> Budget (OMB)'s Circular A-4 [6]. The 3% discount rate represents the social discount rate when consumption is displaced by regulation and the 7% rate represents the social discount rate when capital investment is displaced. Regardless, these are real social discount rates that are riskless. *Therefore, they are not appropriate to use to assess private costs that will be incurred by firms in making their investment decisions. In assessing these private decisions, interest rates that face firms must be used, not social rates* [emphasis added].

As a consequence, the 7% interest rate that Avon Lake cites to should not be used in any way, directly or indirectly, in a regional haze control cost analysis. Avon Lake further states that as a privately held wholesale power generator and not a public utility or subsidiary thereof, GenOn's [Avon Lake's owner] cost of capital is significantly higher than the bank prime rate and the default 7% rate. Avon Lakes states that the financing rates of two other independent coal plants ranged from 11.5 to 12.5%, citing to "Longview Power, LLC bankruptcy exit financing LIBOR + 10% (7/31/20); Homer City Generation LP; bankruptcy exit financing LIBOR + 11% (12/31/20)." It is difficult to understand how the interest rates associated with the bankruptcy exit financing of two other companies in any way relates to the financing for Avon Lake. Nevertheless, the Control Cost Manual is clear on this issue: For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified [emphasis added]."[45] As of the end of May, 2021, the Bank Prime Interest Rate is 3.25%.[46] Using a higher interest rate will artificially increase the total annualized costs and worsen (higher $/ton) the cost-effectiveness of all controls.

9.7 On page 7 of its report, Avon Lake states that although it is calculating the cost-effectiveness of controls using a 20-year equipment life, it is also using a 30-year equipment life due to direction from Ohio. Avon Lake notes, "[t]he Control Cost Manual states that the remaining useful life of a new dry or wet SO_2 scrubbing system should be assumed to be 20 - 30 years." The full context of the Control Cost Manual's statement is:[47]

> As noted in Section 1.1.2, we expect an equipment life of 20 to 30 years for wet FGD systems. One study of coal-fired U.S. power plants found that 50% of the scrubbers at power plants were over 20 years old, with the oldest still operating after 34 years.[27]. The wastewater treatment system can reasonably be expected to operate for over 20 years based on the reported performance characteristics of the wastewater system components. However, the remaining life of the controlled combustion unit may also be a determining factor when deciding on the correct equipment life for calculating the total annual costs. Given these

[45] See Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, November 2017, page 16.
[46] See https://www.federalreserve.gov/releases/h15/.
[47] Control Cost Manual, Section 5, SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021. See page 1-35.

considerations, we estimate an equipment life of 30 years as appropriate for wet FGD systems.

In support of a 20-year life, Avon Lake states "During the first regional haze planning period, a 20-year useful life was used as a default for amortization purposes." This is incorrect. EPA has consistently assumed a thirty-year equipment life for scrubber retrofits, scrubber upgrades, SCRs, and SNCR installations. Much of this is summarized and cited to in EPA's response to comments document for its Texas and Oklahoma Regional Haze SIP final disapproval and FIP.[48]

Avon Lake also cites to many coal-fired EGU retirements and President Biden's Executive Order on Tackling the Climate Crisis at Home and Abroad in which he states the federal government's intent to implement a carbon-free electric power supply sector by 2035. All of this information is indeed true. Avon Lake is free to enter into an enforceable commitment to retire early. If such a commitment is made a part of the Ohio regional haze SIP, then it would be appropriate to base the equipment life on the date of that retirement. Without such an enforceable instrument, an earlier retirement is speculation and not creditable in a SIP.

In many cases, facilities have employed equipment lives that are too short. Regarding this, the Control Cost Manual states:

> The life of the control is defined in this Manual as the equipment life. This is the expected design or operational life of the control equipment. This is not an estimate of the economic life, for there are many parameters and plant-specific considerations that can yield widely differing estimates for a particular type of control equipment.[49]

A number of EGU contractors have been assuming an equipment life of twenty years for SNCR systems, by reference to the Control Cost Manual. The 4/25/2019 SNCR update of the Control Cost Manual does state on page 1-53, "Thus, an equipment lifetime of 20 years is assumed for the SNCR system in this analysis."[50] However, this is a calculation example and does not indicate that EPA universally considers the equipment life for all SNCR systems installed on EGUs to be twenty years. Just prior to this statement, EPA notes:

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[48] *See* Response to Comments for the Federal Register Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze, Docket No. EPA-R06-OAR-2014-0754, 12/9/2015, available here: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0087. *See* pages 240-245, 268, and 274. *See also* the Texas BART FIP proposal, which conducted extensive cost determinations for scrubber upgrades, at 82 FR 930 and 938. *See also* Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, June 2019, pdf page 80: "For the purposes of this cost example, the equipment lifetime of an SCR system is assumed to be 30 years for power plants."

[49] *See* Control Cost Manual, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, November 2017, page 22.

[50] Control Cost Manual, Section 4, Chapter 1, Selective Noncatalytic Reduction, April 2019, page 1-53.

> As mentioned earlier in this chapter, SNCR control systems began to be installed in Japan the late 1980's. Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993. In responses to another Institute of Coal Research (ICR), petroleum refiners estimated SNCR life at between 15 and 25 years.

Therefore, based on a 1993 SNCR installation date, these SNCR systems are at least twenty-eight years old, which all other considerations aside, strongly argues for a thirty-year equipment life. Furthermore, an SNCR system is much less complicated than a SCR system, for which EPA clearly indicates the life should be thirty years. In an SNCR system, the only parts exposed to the exhaust stream are lances with replaceable nozzles. The injection lances must be regularly checked and serviced, but this can be done relatively quickly if necessary, is relatively inexpensive, and should be considered a maintenance item. In this regard, the lances are analogous to SCR catalyst, which is not considered when estimating equipment life. All other items, which comprise the vast majority of the SNCR system capital costs, are outside the exhaust stream and should be considered to last the life of the facility or longer.

Thus, all types of scrubbers, DSI systems, SCR systems, SNCR systems, and NOx combustion controls should have equipment lives of thirty years unless the unit's retirement is secured by an enforceable commitment. Use of a shorter equipment life artificially inflates the cost-effectiveness figures (higher $/ton).

9.8 Avon Lake's SO_2 Analyses

On page 7, Avon Lake summarizes its wet and dry scrubber cost-effectiveness calculations. Avon Lake does not provide any discussion or reference to the cost models employed. However, it appears Avon Lake used the Sargent and Lundy (S&L) wet and dry scrubber cost algorithms commissioned by EPA for use in its IPM modeling. The Control Cost Manual discusses the use of these cost algorithms and allows their use, but cautions that they must be modified to remove AFUDC and owner's' costs.[51] These cost-only algorithms also require other adjustments in order to be used to calculate cost-effectiveness, including an elevation adjustment, an SO_2 baseline, and the capital recovery factor. These cost algorithms, along with the described adjustments have been made and utilized by EPA in the past, including its Texas BART FIP.[52] These algorithms, based on 2012 dollars, have since been updated and are utilized by Avon Lake. [53] In some areas, Avon Lake's treatment of these cost algorithms differs from how EPA has used these algorithms in the past and those differences are discussed below. Avon Lake provides multiple cases for its wet and dry scrubber cost-effectiveness

[51] Control Cost Manual, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021, page 1-49.
[52] See the docket for this action, which contains spreadsheets with these algorithms and the described adjustments.
[53] https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6. See Chapter 5, Emission Control Strategies.

calculations that use different combinations of retrofit factor and equipment life, but only the cases that use a 30-year equipment life and a retrofit factor of 1.0, are reviewed given the inappropriateness of using other calculations.

9.8.1 On page 8, Avon Lake summarizes its wet scrubber cost-effectiveness calculations. As discussed above, Avon Lake has erroneously added owners' costs and AFUDC to its cost analyses. In its wet scrubber cost-effectiveness calculation (Table B-4), these charges inflate the Capital Engineering and Construction Cost (CECC) subtotal by $13,592,000 (5% of CECC) and $28,542,000 (10% of CECC + owners costs), respectively. In addition, Avon Lake has further inflated the CECC by an Engineering Procurement and Construction (EPC) fee of $45,056,000 (15% of CECC + owners' costs). Apparently, Avon Lake has noted that S&L states in the documentation for its cost algorithms, "[s]hould a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated."[54] This is echoed in the Control Cost Manual.[55] However, the Control Cost manual notes that the default approach is that "[t]he capital costs assume the installation is completed using multiple lump sum contracts." In fact, the cost algorithms already include Engineering and Construction Management Costs, which for Avon Lake totals $20,745,000. Therefore, because construction management costs are already included, and there is no reason why Avon Lake could not choose to construct a scrubber "using multiple lump sum contracts," this additional undocumented very large fee should also be deleted. Together, deletion of these unwarranted fees this lowers the CECC by $87,190,000.

It appears that Avon Lake has miscalculated the annual Fixed Operating Costs (FOM) in its scrubber cost-effectiveness calculation. Avon Lake does not disclose how it calculated its FOM, but in Appendix B, Table B-4, it lists the FOM as $5,200,000. According to the S&L algorithms, the FOM is calculated with units of $/kW-yr. Avon Lake calculates this as $8.02/kW-yr. In order to convert this to an annual value, it must be multiplied by the gross load and a conversion factor. The correct equation is:

$$\text{FOM x (Gross Load) x (1000kw/MW) x (yr/8760 hours)}$$

The gross load is 748,173 MWh, based on a 2017 – 2019 average.[56] Therefore, the annual FOM is $8.02/kW-yr x 748,173 MWh x (1000kw/MW) x (yr/8760 hours) = $684,971.

In its fourth case B-4, which uses a 30-year equipment life and a retrofit factor of 1.0, Avon Lake calculates a wet scrubber cost-effectiveness of $16,800/ton. Correcting the issues described above and using an interest rate of 3.25%, results in a wet scrubber cost-effectiveness calculation of $7,651/ton.[57]

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[54] IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final January 2017, Sargent and Lundy.

[55] Control Cost Manual, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021, page 1-49.

[56] Here, a five year average cannot be used, since Avon Lake switched to a different coal in 2016.

[57] These calculations are contained in the file, "Avon Lake Wet FGD Cost Estimate.xlsx."

9.8.2 On page 9 Avon Lake summarizes its dry scrubber cost-effectiveness calculations. The same issues concerning interest rate, equipment life, retrofit factor, AFUDC, owners' costs, and FOM apply here. In addition, Avon Lake has assumed an auxiliary power cost of \$0.06/kWh, when previously in its wet scrubber, SNCR, and SCR cost-effectiveness calculations it used an auxiliary power cost of \$0.025/kWh. Since the 0.06 figure is the default, it is assumed it was overlooked. Avon Lake also assumes a control efficiency of 95%. In this case, this level of control results in a NOx outlet of 0.036 lbs/MMBtu. This is much lower than the typical floor capability of an SDA system, which is typically 0.06 lbs/MMBtu.[58] As a consequence, the level of control was adjusted to 91.55%, which corresponds to an outlet of 0.06 lbs/MMBtu.

In its fourth case B-8, which uses a 30-year equipment life and a retrofit factor of 1.0, Avon Lake calculates a wet scrubber cost-effectiveness of \$14,500/ton. Correcting the issues described above and using an interest rate of 3.25%, results in a wet scrubber cost-effectiveness calculation of \$6,962/ton.[59]

9.9 Avon Lake's NOx Analyses

As with its scrubber cost-effectiveness analyses, Avon Lake provides multiple cases for its SNCR and SCR cost-effectiveness calculations that use different combinations of equipment life, and for SCR retrofit factors. Only the cases that uses a 30-year equipment life, and for SCR a retrofit factor of 1.0, are reviewed.

9.9.1 On page 11 of its report, Avon Lake states

> There is minimal, salvageable infrastructure remaining from the temporary, demonstration SNCR system. If an SNCR is considered, it should be a new system with adequate performance guarantees. An OEM will not be willing to give any performance guarantees with used equipment. Therefore, a new SNCR system was evaluated for costing purposes.

If in fact the previously used equipment can continue to be used, then it would represent a very cost-effective NOx reduction. Therefore, Ohio should require that Avon Lake's statement, that the SNCR system cannot be salvaged, be documented.

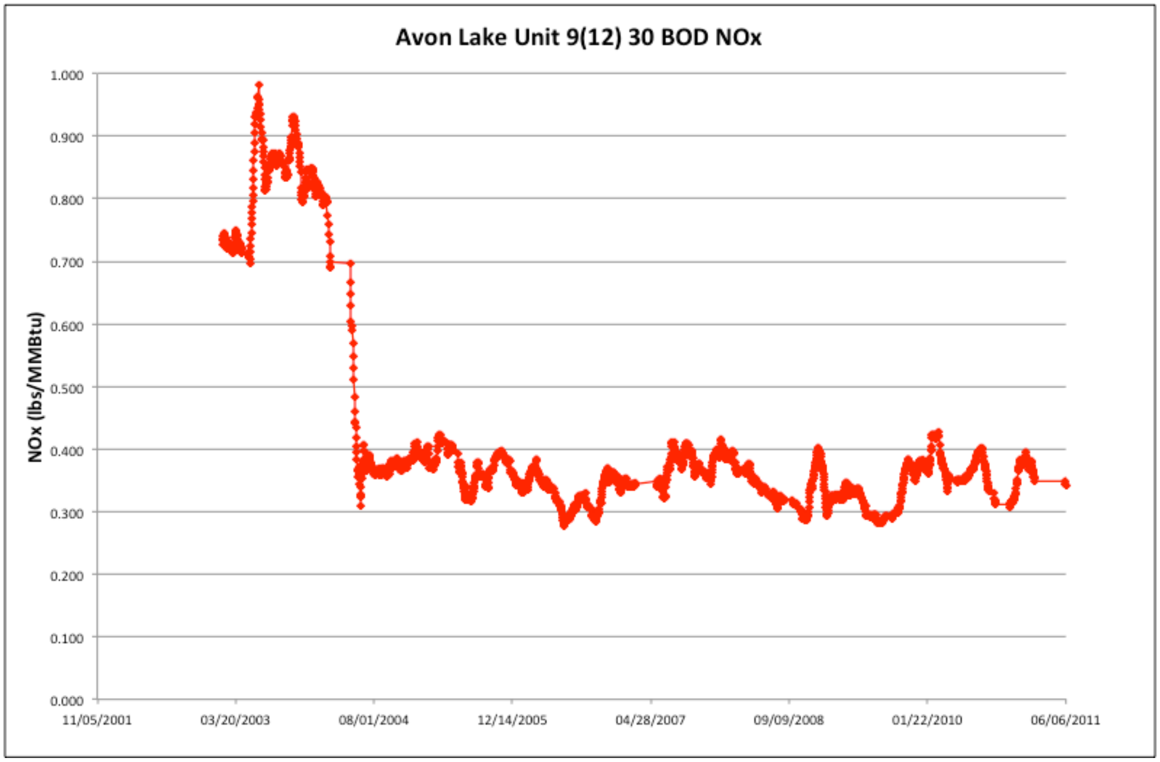
9.9.2 On page 11, Avon Lake states that at loads below 300 MW, the furnace temperatures are too low for SNCR to effectively operate. Because the hourly data show that in 2019, only about 75.36% of the power was generated at loads greater than 300 MW, it uses that percentage in its SNCR cost-effectiveness calculations to reduce the actual MWh output, which significantly worsens the SNCR cost-effectiveness. The Control Cost Manual discusses the temperature sensitivity of typical SNCR systems.[60] Avon Lake should

[58] Note that this level of control may be approachable by other types of dry scrubbing systems, such as a Novel Integrated Desulfurization System (NIDS).
[59] These calculations are contained in the file, "Avon Lake SDA Cost Estimate.xlsx."
[60] See Control Cost Manual, Section 4, Chapter 1, Selective Noncatalytic Reduction, April 2019, page 1-17.

provide documentation of the inlet temperature at various loads so this assertion can be verified.

9.9.3 The SNCR system that Avon Lake installed on Unit 9 (12) was functioning during the 2006-9 ozone seasons, as the following graph indicates:

Figure 20. Avon Lake Unit 9 (12) Selected 30 BOD NOx Emissions



As can be seen from the above graph, it appears that use of the SNCR system during the ozone seasons of 2006-9 reduced the 30 BOD NO_x rate from approximately 0.4 to 0.3 lbs/MMBtu (or better). This represents a reduction of at least 25%. This level of control should be considered an average for urea-based coal-fired EGUs, with control level ranging up to 60% control, as the Control Cost Manual notes. In fact, considering all coal-fired boilers using both urea and ammonia reagents, a 25% level of control is at the low end of the range.[61] Thus, Avon Lake's assumption of 20% control appears to be unsupported. In its SNCR cost-effectiveness calculation, Avon Lake assumes a NOx inlet of 0.327 lbs/MMBtu which it states is "based on actual operation in 2017 - 2019 at >300 MW."[62] That figure appears to be unsupported by the data contained in Avon Lake's report. If the inlet is considered to be 0.4 lbs/MMBtu, which appears to be a

[61] See Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, April 2019. Page 5, Tables 1.1 and 1.2, and Figures 1.1a-1.1b. This is further reinforced by Figure 1.1c, which indicates that at a NOx inlet of 0.4 lbs/MMBtu (approximately Avon Lake Unit 9 (12)'s value) SNCR can be expected to minimally achieve a 25% reduction.
[62] See Appendix B, pdf page 57 of Avon Lake's report.

reasonable figure based on the above graph, and Avon Lake's own outlet of 0.262 lbs/MMBtu is used,[63] then the control level becomes 35%.

9.9.4 The control level effectiveness is very influential in the SNCR cost-effectiveness calculation. For instance, using Avon Lake's own inputs (30-year equipment life, 7% interest rate case, retrofit factor = 1) and changing only the control level from 20% to 25% (inlet = 0.4, outlet = 0.3 lbs/MMBtu), improves the calculated cost-effectiveness from $9,215/ton to $6,375.[64] Further increasing the SNCR control effectiveness to 35%, results in a cost-effectiveness calculation of $4,712/ton. Retaining a 35% control effectiveness and correcting the interest rate from 7% to 3.25%, improves the cost-effectiveness to $3,599/ton. This represents a cost-effective control.

9.9.5 Similar to the control level effectiveness, the amount (in MWh) of the EGU the SNCR system operates is also very influential in the SNCR cost-effectiveness calculation, as the more it operates, the more NOx it can remove, which directly determines the cost-effectiveness ($/ton) calculation. Avon Lake assumes a value of 563,823 MWh. Avon Lake calculates this figure by averaging the total 2017 – 2019 MWh, which is 748,173 MWh, and then multiplying that figure by the fraction of time the unit's generation was 300 MW or greater *during 2019*, which is 0.754. Not only does this approach introduce a mismatch in the time period of the data used, it assumes that the future generation profile should be based on that calculation. Avon Lake has not presented any justification that its generation profile should be based on this approach, especially the use of only one year of data for the fraction of time the unit's generation was 300 MW or greater. Typically, EGUs have used multiple years to support emission baselines, capacities and similarly influential data, unless secured by an enforceable commitment.

A more reasonable approach would minimally be to base the fraction of time the unit's generation was 300 MW or greater on a 2017 – 2019 average. Doing so increases the 0.754 fraction to 0.930, which causes the time the SNCR system operates to increase from 563,823 MWh to 695,801 MWh. This approach would represent a consistent three year averaging of the data. Use of this figure in the SNCR calculations, along with a 30-year equipment life, a 3.25% interest rate, a NOx inlet of 0.4 lbs/MMBtu and an outlet of 0.262 lbs/MMBtu, results in a SNCR cost-effectiveness of $3,082/ton.

An even more reasonable approach would be to base this calculation on five years of data, using an averaging period of 2015 – 2019, which was commonly done by EPA in the first planning period. This results in a 2015 – 2019 average MWh figure of 1,174,329, and a figure of 0.970 for the fraction of time the unit's generation was 300 MW or greater. This revision results in a figure for the time the SNCR system operates of 1,139,099 MWh. Substituting this figure into the SNCR calculation (and retaining the

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[63] See Appendix B, pdf page 57 of Avon Lake's report.

[64] Note that despite using the same inputs in EPA's SNCR cost-effectiveness model, Avon Lake's 30 year, 7% interest, 20% control scenario cost-effectiveness of $9,100 could not be matched exactly, as the value obtained was $9,215/ton. It is suspected the difference is due to rounding of certain inputs. Therefore, in comparisons herein, this value was used as a baseline for consistent comparisons. The final SNCR cost-effectiveness calculation is in the file, "Avon Lake Unit 9 SNCR Cost-Effectiveness.xlsm."

other parameters discussed above), further improves the SNCR cost-effectiveness to \$2,224/ton.[65]

Therefore, even completely ignoring any opportunity to reuse all or portions of Avon Lake's previously operating successful SNCR system, either of these figures represents a cost-effectiveness NOx control.

9.9.6 On page 12 of its report, Avon Lake discusses its SCR cost-effectiveness calculations. As discussed above, the same concerns regarding the length of time the EGU and SCR operate, the retrofit factor, interest rate and equipment life apply. Avon Lake assumes a control efficiency of 90%, which applied to its inlet NOx rate of 0.317 lbs/MMBtu, results in an outlet rate of 0.032 lbs/MMBtu. This outlet rate may be too low unless backed up by a vendor quote or other direct or applicable experience. As discussed in the Cardinal example, a more reasonable NOx outlet floor is 0.04 lbs/MMBtu. If used with an inlet of 0.4 lbs/MMBtu as discussed above, this would also result in an SCR control efficiency of 90%. Even though the control efficiency in both cases is the same, simply raising the inlet has a significant impact on the cost-effectiveness. If these changes are made to Avon Lake's SCR cost-effectiveness calculations, the value changes from \$20,000/ton to \$6,343/ton.[66]

9.10 Avon Lake's Consideration of Visibility

On page 15 of its report, Avon Lake discusses how it considered visibility in its four-factor analysis, citing to the Regional Haze Guidance. In considering visibility, Avon Lake cites to the preamble to the 1999 RHR (64 FR 35730) stating that it establishes a "no degradation" visibility change if the impact is less than 0.1 deciview. This represents a misunderstanding of the meaning of "no degradation." The cited passage is as follows:

> Two options were presented for the presumptive target for the most impaired days: (1) A rate of improvement equivalent to 1.0 deciview over a 10-year period, and (2) a rate of improvement equivalent to 1.0 deciview over a 15-year period. For the least impaired days, EPA proposed a target of no degradation, defined as less than a 0.1 deciview increase.

EPA is therefore discussing how it had proposed to determine whether the "no degradation" requirement for the *least impaired days* would be satisfied. Thus, it is not applicable to a discussion that concerns visibility impairment on the 20% most impaired days. Also, this point does not apply to a source, it concerns the aggregate visibility at a Class I area. Avon Lake also states that, "MANE-VU determined in the first decadal review that a visibility improvement less than 0.1 deciview individual impact does not warrant consideration of additional controls." The cited passage is: "As can be seen in Table 9, the highest individual PM visibility impact (0.0035 dv) is significantly less than the 0.1 deciview individual impact MANE–VU warrants worthy of consideration of BART controls." The MANE-VU 0.1 dv impact was based on CALPUFF "clean

[65] These calculations are contained in the file, "Avon Lake SNCR Cost Estimate.xlsm"
[66] These calculations are contained in the file, "Avon Lake SCR Cost Estimate.xlsm."

background" modeling and is not applicable to the kind of "dirty background" visibility impacts analysis produced by CAMx. EPA explains this and how it developed thresholds for considering whether sources merited controls when using dirty background modeling, like CAMx, in its Texas BART FIP. EPA developed a 0.3% contribution threshold as a cut point for further evaluation. This was based on individual unit contributions at any Class I Area on the 20% worst days.[67] Avon Lake's analysis of visibility impacts against a dirty background is simply not germane to whether it should be controlled.

10 Review of the Carmeuse Maple Grove Lime Four-Factor Analysis

The Carmeuse Maple Grove Lime four-factor analysis was reviewed.[68] In addition, comments are offered concerning the Carmeuse Maple Grove affordability analysis.[69]

10.1 On page 3-6 of its report, Carmeuse states that it eliminated switching Kilns 1 and 2 from coal and coke to natural gas because it would constitute a process change and would be too fundamental to the operation and design of the source. Carmeuse is permitted to use natural gas in its kilns and in fact does so to some extent. Carmeuse cites to the Regional Haze Guidance to support its position but does not provide a specific page number. The Regional Haze Guidance states the following regarding fuel switching [emphasis added]:[70]

> States have the flexibility to reasonably determine which control measures to evaluate, and the following is a list of example types of control measures that states may consider:
>
> - Emission reductions through improved work practices.
> - Retrofits for sources with no existing controls.
> - Upgrades or replacements for existing, less effective controls.
> - Year-round operation of existing controls.
> - *Fuel mix with inherently lower SO_2, NOx , and/or PM emissions. States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.*
> - Operating restrictions on hours, fuel input, or product output to reduce emissions. Energy efficiency and renewable energy measures that could be applied elsewhere in a state to reduce emissions from EGUs.
> - Basic smoke management practices and smoke management programs for agricultural or wildland prescribed fires.

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[67] Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD), November 2014, Appendix A.
[68] Regional Haze Four-Factor Analysis, Carmeuse Lime, Inc., Bettsville, Ohio, Prepared By: Carmeuse Lime and Trinity Consultants, Revised April 2021.
[69] Letter to Holly Kaloz from Ray Rummel, dated April 27, 2001.
[70] Regional Haze Guidance, page 29.

EPA's Regional Haze Guidance clearly informs states that they may consider fuel mixes that inherently lower SO_2, NOx, or PM emissions. Although Carmeuse states a switch to natural gas would cause a process change that would be too fundamental to the design and operation of the kilns, it does not provide any documentation to support that position. In fact, following this statement, it provides a brief listing of six reasons why or how this change would however have both chemical and economic impacts on the Maple Grove operation. With the exception of its statement that there is insufficient natural gas supply, none of these reasons appear to eliminate a full or partial switch to natural gas from a purely technical infeasibility standpoint. Therefore, it appears the only issue limiting a full or partial switch to natural gas is cost and availability. Ohio should therefore investigate this claim and require documentation from Carmeuse to support its position.

10.2 Beginning on page 4-4, Carmeuse discusses why it believes it should use an interest rate of 7%, in lieu of the current Bank Prime rate of 3.25%. For the same reasons discussed in the review of the Avon Lake analyses, Carmeuse misunderstands the Control Cost Manual's position on the OMB Circular to which it cites. The Control Cost Manual is clear on this issue: For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified [emphasis added]."[71] As of the end of May, 2021, the Bank Prime Interest Rate is 3.25%.[72] Using a higher interest rate will artificially increase the total annualized costs and worsen (higher $/ton) the cost-effectiveness of all controls. Therefore, unless Carmeuse provides documentation that supports an alternative interest rate, it should use an interest rate of 3.25% in all its cost-effectiveness analyses.

10.3 Carmeuse Maple Grove NOx Analysis

10.3.1 Beginning on page 3-10, Carmeuse makes a number of claims supporting its contention that both high-dust and tail-end SCR systems are technically infeasible. These claims include the fouling or plugging of a high dust SCR installation, and catalyst poisoning in a tail-end configuration. Carmeuse also claims that the ammonia utilized as a reducing agent in the SCR can react with the SO_3 or H_2SO_4 present in the exhaust stream to form ammonium sulfate or ammonium bisulfate which can condense within the catalyst pores or produce a high opacity visible plume at the stack exhaust. None of these contentions have been supported in any way.

All of these issues relate to maintenance and not technical feasibility. SCR system operators have been successfully addressing these and other maintenance issues on a wide variety of source types for decades.[73] The Control Cost Manual contains a great deal of information concerning the costing, design and historically successful operation of SCR systems on cement kilns, a similar type of source. This information addresses all of these claims, specifically from the operational standpoint of cement kilns. Although

71 See Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, November 2017, page 16.
72 See https://www.federalreserve.gov/releases/h15/.
73 For instance, see Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, June 2019, Tables 2.1a – 2.1b.

beyond the scope of this report, Ohio is encouraged to consult this information. As Carmeuse notes, "The type of dust generated from Kilns #1 and #2 is similar to dust generated in PH/PC cement kilns."[74] Also, many cement kilns use the same types of feed stock and fuels as the Carmeuse kilns. Therefore, there is little to distinguish the installation of an SCR system on a cement kiln from the type of kilns Carmeuse operates. For example, SCR was required by a consent decree at the Lafarge Joppa plant in Illinois.[75] As Lafarge itself noted in its 2014 annual report, SCR "installed at Joppa plant reduced NOx by up to 80%."[76] The Lafarge Holcim[77] cement plant in Midlothian, TX also installed SCR with a reported efficiency of at least 70%.[78] These and other commonly cited to issues are discussed in detail and rejected as cause infeasibility in a Texas Commission on Environmental Quality Report concerning the application of SCR systems at a number of cement kilns.[79] Ohio should therefore require that either Carmeuse prove these claims, or it should assume both of these SCR configurations are technically feasible.

10.3.2 In its SCR cost-effectiveness analysis, Carmeuse indicates on page 5-1 that it is assuming a control efficiency of 70%. Carmeuse's only support for this figure appears to be its citation to a 5-page EPA fact sheet, intended to provide an overview of SCR technology.[80] As even this elementary document indicates, "SCR is capable of NOx reduction efficiencies in the range of 70% to 90%." In evaluating cement kilns in Texas, the previously cited to Texas Commission on Environmental Quality report stated:[81]

> For example, performance levels for selective catalytic reduction (SCR) and LoTOx TM oxidation are conservatively estimated at 80-85%. These technologies typically perform better than these levels in other industrial applications. However, using a slightly lower performance value presents a more conservative evaluation of control costs, allowing potential difficulties in initial application of these technologies to Ellis County cement kilns.

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[74] See page 3-10 of the Carmeuse report.
[75] See https://www.epa.gov/enforcement/lafarge-north-america-inc-clean-air-act-settlement.
[76] See page Annual Report, Registration Document, Lafarge 2014, page 141. https://www.lafargeholcim.com/sites/lafargeholcim.com/files/atoms/files/03232015-press_publication-2014_annual_report-uk.pdf
[77] Lafarge and Holcim have recently merged.
[78] See https://www.midlothianmirror.com/news/20170718/holcim-makes-environmental-improvements-with-new-regulation-updates.
[79] Assessment Of NOx Emissions Reduction Strategies For Cement Kilns - Ellis County Final Report, TCEQ Contract No. 582-04-65589 Work Order No.05-06, Prepared by: ERG, Inc., Prepared for: Texas Commission on Environmental Quality, July 14, 2006. Available here: https://www.tceq.texas.gov/assets/public/implementation/air/sip/agreements/BSA/CEMENT_FINAL_REPORT_70514_final.pdf.
[80] EPA Air Pollution Control Technology Fact Sheet, EPA-452/F-03-032, available here: https://www3.epa.gov/ttncatc1/dir1/fscr.pdf.
[81] Assessment Of NOx Emissions Reduction Strategies For Cement Kilns - Ellis County Final Report, TCEQ Contract No. 582-04-65589 Work Order No.05-06, Prepared by: ERG, Inc., Prepared for: Texas Commission on Environmental Quality, July 14, 2006. Page 1-2.

As a consequence, the Carmeuse SCR system cost-effectiveness should be performed on the basis of at least 85% efficiency.

10.3.3 Carmeuse concedes that it is performing a SCR cost-effectiveness analysis at the request of Ohio. However, it states that due to the risk of catalyst poisoning and opacity from formation of aerosols, its SCR cost includes the installation of a wet scrubber to minimize SO_2 emissions upstream of the SCR. Again, Carmeuse has not documented the need for this additional cost adder. No reasoning has been presented that would preclude the installation of a high-dust SCR installation. Thus, considering the long established record of successful high-dust SCR installations discussed above, including the dry kilns discussed in the TCEQ referenced report, that cost should be deleted. Compounding this unwarranted cost adder, Carmeuse further includes the cost of a gas reheater downstream of the wet scrubber in order to raise the gas temperature back up to the level needed to make catalyst operate effectively. In a high-dust configuration, there is usually no need for reheat (since the gas would not be cooled by passing through a wet scrubber) and this cost should also be deleted.

10.3.4 Carmeuse does not provide any explanation of how it conducted its SCR cost-effectiveness calculations. However, it appears it has assumed that the Control Cost Manual's SCR equations for industrial coal-fired boilers are appropriate.[82] Carmeuse has provided no reasoning why SCR costing equations designed for industrial boilers are appropriate for its kilns. Because of this, a revised cost-effectiveness calculation that depends on Carmeuse's figures cannot be made in this report. Thus, Ohio should require that Carmeuse either demonstrate that its adoption of these equations is appropriate, or revise its SCR calculations using relevant estimating techniques. It should be noted, that in addition to the TCEQ finding that similar claims Carmeuse makes regarding technical infeasibility were meritless its determined that SCR systems at the dry cement kilns it evaluated were very cost-effective at $1,900/ton to $2,000/tom for the two high-dust Holcim dry kilns it evaluated. Considering this, Ohio should require a more appropriate, robust, and well documented SCR cost-effectiveness analysis from Carmeuse.

10.3.5 In its NOx control discussion, Carmeuse does not consider air mixing technology. As discussed in the Magnesita York, PA four-factor analysis, that facility is currently installing an enhanced air mixing technology on its kilns to reduce NOx. These kilns are similar to those used by Carmeuse and are cited to by Carmeuse in its lime kiln dead-burn survey. Magnesita states this technology is currently in use on a similar kiln at its plant in Austria.[83] If this technology is licensable, Ohio should require that it be considered by Carmeuse.

10.3.6 On page 4-8, Carmeuse briefly states that it is using an equipment life of 20 years for its control cost-effectiveness calculations. For the reasons discussed elsewhere in this report,

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[82] See Carmeuse's SCR cost-effectiveness calculations in Appendix A of its report, pdf page 48: "CCM, Section 4, Chapter 2, Eqn 2.48 (June 2019). 310,000 = constant in equation." Equation 2.48 is in fact used on the Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, June 2019, pdf page 71.

[83] Regional Haze Four-Factor Analysis, Magnesita York, PA, Prepared By: Magnesita and Trinity Consultants, July 2020 (Revised October 2020).

a 30-year equipment life should be used for all control equipment. With regard to its selection of a 20 year equipment life for DSI, Carmeuse cites to Section 6, Chapter 1 of the Control Cost Manual and reasons that the useful life of the DSI and Conditioning Tower Slurry Injection systems should based on the life of the replacement baghouse per CCM. With regard to this, the Control Cost Manual states the following:[84]

> The capital recovery cost is based on the equipment lifetime and the annual interest rate employed. (See Section 1 for a discussion of the capital recovery cost and the variables that determine it.) For fabric filters, the system lifetime varies from 5 to 40 years, with 20 years being typical. However, this does not apply to the bags, which usually have much shorter lives. Therefore, one should base system capital recovery cost estimates on the installed capital cost, less the cost of replacing the bags (i.e., the purchased cost of the bags plus the cost of labor necessary to replace them).

A typical baghouse is a simple, robust piece of equipment, constructed of structural steel, with few moving parts. As the Control Cost Manual states, the system lifetime of a typical baghouse varies from 5 to 40 years, with the bags themselves being considered maintenance items. Baghouses are widely used as a particulate control in many different industries and thus have long established service records. Furthermore, it is important to note that this section of the Control Cost Manual was written in 1998 and has not been updated. Since that time, there are many examples of baghouses having been in service in the power industry, where they are exposed to fly ash, for more than 20 years.[85] In addition, baghouse are integral to DSI and dry scrubbers, and yet these controls have equipment lives of 30 years. Therefore, unless Carmeuse can provide additional information that documents why baghouses installed at its facility should be treated differently from those in other industries and cement manufacturers, it should use an equipment life of 30 years.

10.4 Carmeuse Maple Grove SO_2 Analysis

10.4.1 On page 4-3, Carmeuse states that it is assuming a 1.2 retrofit factor in its DSI and Conditioning Tower Slurry Injection SO_2 cost-effectiveness calculations. Carmeuse has not provided any documentation for this cost adder, simply reasoning on page 4-4:

> For the installation of the DSI and Conditioning Tower Slurry Injection systems, the retrofit factor is 1.2 due to required replacement of the fabric filter on each rotary kiln. Installation of the fabric filters will require replacement of one existing filter unit in combination with process

[84] Control Cost Manual, Section 6, Particulate Matter Controls, Chapter 1 Baghouses and Filters, December 1998. Page 1-48.
[85] For instance, see this 2010 report: Power Plant Baghouse Survey 2010, 2010 EPRI Technical Report, available here: https://www.epri.com/#/pages/product/1019729/. This report discusses a number of case histories of facilities that had installed baghouses that are still in service. There a many examples that exceed 20 years in service.

downtime for demolition of the existing units and construction of the new units. Site conditions and the proximity of the two kilns does not allow construction of a new filter while operating the existing units. In addition, relocation of the associated ducts will require construction of additional structural support.

In fact, almost every control system installation involves replacement of existing structures that involves some demolition of existing structures and construction of new structures. As the Control Cost Manual indicates, a retrofit factor of 1.0 represents a retrofit of average difficulty. Therefore, because Carmeuse's use of this retrofit factor would increase the total capital investment by 20%, Ohio should require more documentation from Carmeuse that the installation of these controls represents retrofits that are more complex that average.

10.4.2 On page 4-1, Carmeuse presents the control efficiencies it assumed for DSI of 50%, conditioning tower slurry injection of 39%, and wet scrubbing of 50%. Carmeuse states the figures for DSI and the conditioning tower slurry injection were obtained from vendor quotes. Those quotes are provided in Appendix B. The BSCI quote is actually a hydrated lime DSI system for two boilers at a plant in Akron, Ohio. It does not appear any information is provided that would indicate this quote is applicable to the Carmeuse kilns, or that Carmeuse's assumed DSI control efficiency is appropriate. Also, while the quote provided for the conditioning tower slurry injection is based on a 39% control efficiency, there is no indication this level of control is the maximum available from this system. In fact, the vendor states, "High scrubbing efficiencies can be achieved where required by the process." Therefore in this review, an additional level of control equal to a 50% efficiency is assumed. Compared to other scrubbing systems, even this level of control is low.

10.4.3 Carmeuse states the control efficiency for the wet scrubber was based on "Engineering determination based on inlet loading SO_2 concentration." Additional discussion was provided on page 4-2. However, no actual references or calculations were provided to support Carmeuse's reasoning. It seems that Carmeuse's main point is that as NOx inlet decreases, the control effectiveness of a wet scrubber also decreases. Considering that this parameter has a significant impact on the cost-effectiveness calculation, Ohio should either require that a much higher efficiency be assumed, or that Carmeuse provide documentation to support its claims.

10.4.4 The following is a summarized version of Carmeuse's SO_2 cost-effectiveness calculations, which it presents in Appendix A of its report. In addition, revised calculations are also presented in which Carmeuse's interest rate is corrected from 7% to 3.25%, its equipment life is corrected from 20 to 30 years, and the retrofit factor for its DSI and conditioning tower slurry injection is corrected from 1.2 to 1.0.[86]

[86] It should be noted that as indicated earlier, the DSI quote Carmeuse adopted was intended for two boilers at another facility. No information has been provided to indicate these quotes are applicable to the Carmeuse kilns. They have been reviewed here due to their simplicity and as a general indicator but these quotes should not be viewed as determinative.

Revised calculations are also presented in which the control efficiency for the conditioning tower slurry injection is increased from 39% to 50%, and for which the wet scrubber efficiency is increased from 50% to 75%. These latter cases are presented to illustrate the significant impact control efficiency has on the cost-effectiveness calculation, so that Ohio will place the proper emphasis on obtaining adequate documentation:[87]

Table 3. Summarization of Carmeuse SO_2 Cost-effectiveness Calculations

Control	Efficiency (%)	Carmeuse ($/ton)	Revised ($/ton)
DSI Kiln 1	50	5,857	5,310
DSI Kiln 2	50	5,862	5,312
Conditioning Tower Slurry Injection Kiln 1	39	3,266	2,670
Conditioning Tower Slurry Injection Kiln 2	39	3,274	2,676
Conditioning Tower Slurry Injection Kiln 1	50	N/A	2,082
Conditioning Tower Slurry Injection Kiln 2	50	N/A	2,086
Wet scrubber Kiln 1	50	4,056	3,423
Wet scrubber Kiln 2	50	4,043	3,407
Wet scrubber Kiln 1	75	N/A	2,282
Wet scrubber Kiln 2	75	N/A	2,272

The above figures are based on accepting Carmeuse's cost items, which as discussed above, should be documented. Nevertheless, it is apparent that the revised calculations for cost-effectiveness indicate that minimally, the conditioning tower slurry injection and wet scrubber technologies are cost-effective.

10.5 Comments on the Carmeuse Affordability Analysis

Considering the analyses provided herein, it is apparent that SO_2 controls are available for retrofit to the Carmeuse kilns at cost-effectiveness levels that have previously been found to be cost-effective by many states. Information has also been presented that indicates that SCR experience in the cement kiln industry is relevant, which makes it highly likely that SCR is technically feasible for retrofit on the Carmeuse kilns. Furthermore, the SCR cost analysis provided by Carmeuse uses an inappropriate costing methodology. In addition, due to the inclusion of inappropriate cost adders, this analysis is highly inflated. Based on the TCEQ's own analysis and figures (discussed above), it is likely that SCR systems retrofitted on the Carmeuse kilns will be much lower and cost-

[87] See the file, "Carmeuse cost-effectiveness.xlsx" for all cost-effectiveness recalculations.

effective. Consequently, the figures Carmeuse presents in its affordability analysis are likely overstated.

Ohio is urged to take note that many cement kilns have installed advanced NOx and SO_2 controls and continue to be competitive. In addition, as noted in Magnesita's own four-factor analysis, it is in the process of enhanced air mixing technology for the control of NOx emissions and dry sorbent injection (DSI) technology for the control of SO_2. Magnesita kilns produce dolomite sinter and are very similar to Carmeuse's kilns.

11 Review of the Dover Four-Factor Analysis

The Dover Municipal Light Plant four-factor analysis was reviewed.[88] This report is only 16 pages in length.

11.1 In its wet scrubber cost-effectiveness calculation, Dover properly use a 30-year equipment life and an interest rate of 3.25%. In addition, it appears that Dover has generally followed the Control Cost Manual, using appropriate costing algorithms and not including disallowed cost items such as AFUDC and owners' costs.

However, it appears that Dover's assumed control efficiencies are low. Dover has assumed a wet scrubber control efficiency of 94%, which when applied to its SO_2 inlet of 2.17 lbs/MMBtu results in an outlet of 0.13 lbs/MMBtu. A more appropriate control efficiency would be 98%, would result in an outlet of 0.04. Similarly, Dover assumed a dry scrubber control efficiency of 93.5%, resulting in an outlet of 0.14 lbs/MMBtu. A more appropriate dry scrubber control efficiency would be 95%, resulting in an outlet of 0.10 lbs/MMBtu. These are relatively minor changes that are not expected to significantly improve the cost-effectiveness.

11.2 Dover does not consider any NOx controls in its four-factor analysis. Ohio should explain why Dover is not required to include NOx in its four-factor analysis, and lacking a reasoned justification, require the four-factor analysis.

11.3 Apparently, Dover's size is too small to be required to report its emissions to EPA. However, despite its small size, it has relatively high SO_2 emissions, averaging 979 tpy. This is apparently due to the relatively high sulfur content of the coal it burns. Ohio should disclose how it collects emissions data from Dover.

12 Ohio's Decisions on Reasonable Progress Control Measures are Based on Incorrect Information

Beginning on page 47, Ohio describes how it has considered the four factors in assessing reasonable progress. For Ohio, the controlling factor in all cases appears to be cost. Regarding this, Ohio states:

[88] Regional Haze Four-Factor Analysis, Dover Municipal Light Plant , Prepared By: Dover Municipal Light Plant and Trinity Consultants, March 2021.

> Additional SO_2 or NOx controls are clearly not cost-effective for Avon Lake Power Plant. While the cost-effectiveness of SO_2 controls at Carmeuse Lime – Maple Grove and Dover Municipal Light are lower in comparison to Avon Lake Power Plant, these sources have both included an analysis showing the added costs of these controls are not affordable. No technically feasible control measures were identified for SO_2 control at Gavin Power Plant beyond existing wet FGD systems, or for NOx control at Carmeuse Lime – Maple Grove beyond current operation under good combustion practices.

However, as has been discussed in this report, with the exception of Dover, all the cost-effectiveness calculations reviewed are demonstrably inflated, due to the use of inappropriate or minimally undocumented parameters, control efficiencies that are too low, or inappropriate cost adders. Therefore, Ohio's principal determinant is based on incorrect information. Ohio should therefore require that all of these cost-effectiveness issues be properly documented or corrected to inform its final control decisions. It is likely that most of these units have available cost-effective controls that will significantly reduce emissions and otherwise satisfy the four factor reasonable progress analysis.

13 Ohio Should Require Additional Four-Factor Analyses

Ohio has only required four-factor analyses for the Dover, Avon Lake, Carmeuse and Gavin facilities. As described in this report, there are a number of other sources that did not submit four-factor analyses, which nevertheless could demonstrably lower their NOx and/or SO_2 emissions through controls, control upgrades, or continuous operation of controls that are in typically very cost-effective. This includes:

- Scrubber upgrades on the Cardinal units.
- SCR optimization/upgrades on the Cardinal units.
- A scrubber upgrade on Bay Shore Unit 1.
- Scrubber upgrades on the Gavin units.
- Continuous operation and SCR optimization/upgrades on the Gavin.
- Continuous operation and SCR optimization/upgrades on the Kyger Creek units.
- Scrubber upgrades on the WH Sammis units.
- SCR optimization/upgrades for the WH Sammis Units 6 and 7.
- SNCR optimization for WH Sammis Unit 5.

In addition, in a number of cases, units are operating considerably below their permitted limits. Some of these units are satisfying their MATS HCl obligations directly, and so do not have an SO_2 limit under MATS. Because cost-effectiveness calculations are based on historical emission data, there is nothing preventing these units from greatly increasing their emissions. Accordingly, Ohio must reevaluate the four statutory factors and determine whether more stringent, technically achievable and cost effective emission limits are necessary to ensure reasonable progress.

14 Ohio's Consideration of Affordability

On page 39, Ohio states that it has considered the affordability of controls for some of its sources. As Ohio notes, there is no provision within the Regional Haze Rule to consider affordability. However, EPA advised states within the BART Guidelines that the affordability of controls could be considered under BART. In so doing, EPA cautions states that these situations should be considered to be "unusual," and that considerations should include "effects on product prices, the market share, and profitability of the source."[89] In that same section, EPA states:

> Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.

Thus, EPA places great emphasis on documentation in any consideration of affordability As has been demonstrated in Carmeuse's case, its cost analyses are demonstrably inflated. SO_2 and NOx controls are available for retrofit to the Carmeuse kilns at cost-effectiveness levels that have previously been found to be cost-effective by many states.

At a minimum, Ohio must judge affordability based on a sound and well documented cost-analysis. Lastly, there is no mention of affordability in any subsequent revision to the Regional Haze Rule, the recent Regional Haze Guidance, or the applicable sections of the Clean Air Act. Therefore, Ohio must not elevate affordability considerations above the statutorily required four factors.

15 Issues Relating to Consultation

15.1 On page 56, Ohio describes how it responded to the MANE-VU Ask. The issues contained in Request 1 and 4 are of particular relevance [emphasis added]:

> 1. EGUs with a nameplate capacity larger than or equal to 25 MW with already installed NOx and/or SO_2 controls - *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;
>
> 4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels - *pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM.* The permit,

[89] 70 FR 39171 (July 6, 2005).

enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;

Although Ohio states it followed the MANE-VU first request, it does not appear it has done so, considering the issued described in the previous comment. For instance, as summarized above, in a number of cases, Ohio has not required that certain sources perform reasonable upgrades and optimizations of existing controls, or that those controls be continuously run at their full capabilities. Regarding MANE-VU's fourth request, Ohio states that in most cases the fuel switch is already incorporated into federally-enforceable permits but that it does not agree that establishing lower emission rates commensurate with the fuel switch is either required or appropriate. Again, it is evident that some sources have considerable compliance latitude with regard to their permitting limits. Ohio is urged to reconsider examining permit limits for any source that is operating substantially under its permit limits and revise such limits accordingly, including the emission limits and monitoring, recordkeeping and reporting requirements in the SIP.

15.2 On page 57, Ohio summarizes how it replied to the VISTAS Ask. Ohio states that on behalf of Alabama, Georgia, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia, it requested that Ohio conduct a reasonable progress analysis for four Ohio sources that were identified by VISTAS to have an impact on visibility in Class I areas located in VISTAS states. An examination of the VISTAS letter, indicates these sources are Kyger Creek, Cardinal, Gavin, and WH Zimmer.[90] As Ohio indicates elsewhere in its SIP, the WH Zimmer is scheduled to retire, although that commitment is apparently not fully executed and practically enforceable in its SIP. Ohio's response letter echoed statements expressed in its SIP – largely that it considers these sources already "effectively controlled." However, as described above, Kyger Creek, Cardinal, and Gavin likely have cost-effective controls options available. Also, contrary to the VISTAS Ask, Ohio did not even require that Kyger Creek and Cardinal prepare four-factor analyses, and it has not required that Gavin properly assess scrubber and SCR optimization/upgrades. Again, Ohio should require that four-factor analyses be performed for Cardinal and Kyger Creek and that Gavin properly consider optimization/upgrades to its scrubber and SCR systems.

[90] Letter from John E. Hornback to Robert F. Hodanbosi, dated June 22, 2020.