Technical Support Document (TSD)

for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

Docket ID No. EPA-HQ-OAR-2021-0668

EGU NO_X Mitigation Strategies Proposed Rule TSD

U.S. Environmental Protection Agency

Office of Air and Radiation

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A. Introduction:

The analysis presented in this document supports the EPA's proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (Cross-State Air Pollution Rule for the 2015 Ozone NAAQS). In developing this proposal, the EPA considered all NO_X control strategies that are widely in use by EGUs, listed below. This Technical Support Document (TSD) discusses costs, emission reduction potential, and feasibility related to these EGU NO_X emission control strategies. Specifically, this TSD explores three topics: (1) the appropriate representative cost resulting from "widespread" implementation of a particular NO_X emission control technology; (2) the NO_X emission rates widely achievable by "fully operating" emission control equipment; and (3) the time required to implement these EGU NO_X control strategies (e.g., installing and/or restoring an emission control system to full operation or shifting generation to reduce NO_X emissions). These analyses inform the EPA's evaluation of costs and emission reductions in Step 3 of its four step interstate transport framework.

NO_X control strategies that are widely available for EGUs include:

- Returning to full operation any existing SCRs that have operated at fractional design capability;
- Restarting inactive SCRs and returning them to full operation;
- Restarting inactive SNCRs and/or returning to full operation any SNCRs that have operated at fractional design capability;

- Upgrading combustion controls with newer, more advanced technology (e.g., state-of-the-art low NO_X burners);
- Installing new SCR systems;
- Installing new SNCR systems; and
- Shifting generation (i.e., changing dispatch) from high- to low-emitting or zero-emitting units.

To evaluate the cost for some of these EGU NO_X reduction strategies, the agency used the capital expenses, fixed and variable operation and maintenance costs for installing and fully operating emission controls based on the cost equations used within the Integrated Planning Model (IPM) that were researched by Sargent & Lundy, a nationally recognized architect/engineering firm with the EGU sector expertise.[1] From this research, EPA has created a publicly available Excel-based tool called the Retrofit Cost Analyzer (Update 1-26-2022) that implements these cost equations.[2] Application of the Retrofit Cost Analyzer equations to the existing EGU fleet can be found in the docket.[3] EPA also used the Integrated Planning Model (IPM) to analyze power sector response while accounting for electricity market dynamics such as generation shifting.

The costs presented in the TSD are in 2016 dollars, unless otherwise noted. For some cost estimates, EPA provides multiple statistics to describe the cost. These include: the "emission weighted average," which is the total cost of the mitigation strategy applied to the applicable units divided by the total tons of NO_X reduced; the "median," which is the cost of the mitigation strategy at the median, or 50th percentile, *unit*; and the "90th percentile", which is the cost of the mitigation strategy at the 90th percentile *unit*.

B. Optimizing and Restarting Existing SCRs

1. Cost Estimates for Optimizing and Restarting Existing SCRs

Coal Steam:

EPA examined costs for full operation of SCR controls for units that already have this technology installed. SCR systems are post-combustion controls that reduce NO_X emissions by reacting the NO_X with a reagent (typically ammonia or urea). The SCR technology utilizes a catalyst to increase the conversion efficiency and produces high conversion of NO_X. Over time with use, the catalyst will degrade and require replacement. The ammonia or urea reagent is also consumed in the NO_X conversion process. Fully operating an SCR includes maintenance costs, labor, auxiliary power, catalyst, and reagent cost. The chemical reagent (typically ammonia or urea) is a significant portion of the operating cost of these

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[1] The underlying equations come from data and information in the following reports:

- "IPM Model – Updates to Cost and Performance for APC Technologies: SCR Cost Development Methodology for Coal-fired Boilers" (February 2022) ("Coal-Fired SCR Cost Methodology" for short)
- "IPM Model – Updates to Cost and Performance for APC Technologies: SNCR Cost Development Methodology for Coal-fired Boilers" (August 2021) ("Coal-Fired SNCR Cost Methodology" for short)
- "IPM Model – Updates to Cost and Performance for APC Technologies: SCR Cost Development Methodology for Oil/Gas-fired Boilers" (August 2021) ("Gas-Fired SCR Cost Methodology" for short)
- "IPM Model – Updates to Cost and Performance for APC Technologies: SNCR Cost Development Methodology for Oil/Gas-fired Boilers" (August 2021) (" Gas-Fired SNCR Cost Methodology" for short)
- "Combustion Turbine NOX Technology Memo" (January 2022)
- "Typical SCR and SNCR Schedule (Coal or Oil/Gas boilers)" (February 2022)

[2] See https://www.epa.gov/airmarkets/retrofit-cost-analyzer for the "Retrofit Cost Analyzer (Update 1-26-2022)" Excel tool

[3] See the file "NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx" for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

controls. For a unit with an idled, bypassed, or mothballed SCR, all fixed operating and maintenance (FOM) and variable operations and maintenance (VOM) costs such as auxiliary fan power, catalyst costs, and additional administrative costs (labor) are realized upon resuming operation through full potential capability.

EPA examined the costs to fully operate an SCR that was already being operated to some extent and the costs to restart and fully operate an SCR that had been idled using the equations within the Retrofit Cost Analyzer. There are VOM costs related to the consumption of reagent and degradation of the catalyst as well as FOM costs related to maintaining and operating the equipment to be considered that pertain to these two situations.

EPA examined three of the VOM costs illustrated in the Retrofit Cost Analyzer: reagent, catalyst, and auxiliary power. Depending on circumstances, SCR operators may operate the system while achieving less than “full” removal efficiency by using less reagent, and/or not replacing degraded catalyst which allows the SCR to perform at lower reduction capabilities. For units where the SCR has been idled, there would be no reagent or catalyst utilized. Consequently, the EPA finds it reasonable to include the costs of both additional reagent and catalyst maintenance and replacement in representing the cost of optimizing operating SCR systems and also to include these costs for restarting idled systems. In contrast, based on the Retrofit Cost Analyzer equations, the auxiliary power component of VOM is largely indifferent to the NO_X removal. That is, auxiliary power is indifferent to reagent consumption, catalyst degradation, or NO_X removal rate. Therefore, for units where the SCR is operating, but may not be fully operating, the auxiliary power VOM component has likely been incurred. For units where the SCR has been idled, this cost component needs to be accounted for when assessing the cost to restart and fully optimize the SCR control.

In addition, based on the Retrofit Cost Analyzer equations for FOM, units running their SCR systems have incurred the complete set of FOM costs, regardless of reagent consumption, catalyst degradation, or NO_X removal rate. Thus, as was the case for the auxiliary power VOM cost component, the FOM cost component is also not included in the cost estimate to achieve “full” operation for units that are already operating. For units where the SCR has been idled, all of the FOM costs would need to be accounted for when assessing the cost to restart and fully optimize the SCR control. In conclusion, EPA finds that only the VOM reagent and catalyst replacement costs should be included in cost estimates for optimization of partially operating SCRs, while the full suite of VOM and FOM costs should be included when assessing the cost to restart and fully optimize the SCR control. EPA assessed these costs using both representative units as well as assessment of the existing fleet of EGUs with these controls.

In an SCR, the chemical reaction consumes approximately 0.57 tons of ammonia or 1 ton of urea reagent for every ton of NO_X removed. During development of the Clean Air Interstate Rule (CAIR) and the original CSAPR, the agency identified a marginal cost of \$500/ton of NO_X removed (1999\$) with ammonia costing \$190/ton of ammonia, which equated to \$108/ton of NO_X removed for the reagent procurement portion of operations. The remaining balance reflected other operating costs. Over the years, reagent commodity prices have changed, affecting the operational cost in relation to reagent procurement. For data on the relationship between reagent price and its associated cost regarding NO_X reduction, see Appendix A: “Historical Anhydrous Ammonia and Urea Costs and their Associated Cost per NO_X ton Removed in a SCR.” These commodities are created in large quantities for use in the agriculture sector. Demand from the power sector for use in pollution controls is small relative to the magnitude used in agriculture. Fluctuations in price are expected and are demonstrated in the pricing data presented in Appendix A. Some of these prices reflect conditions where demand and commodity prices are high. Consequently, the reagent costs used by EPA in this proposal are representative. In the cost estimates presented here, EPA uses the cost for urea, which is greater than ammonia costs, to arrive at a conservative estimate. In the CSAPR Update, EPA used the default cost of $310/ton for a 50% weight solution of urea in the Retrofit Cost Analyzer. With the updates to the Retrofit Cost Analyzer, the default costs of the urea reagent also increased to $350/ton for a 50% weight solution of urea. In this action, considering the most recent updates to the Retrofit Cost Analyzer, EPA assumed the cost of $350/ton for a 50% weight solution of urea. Using the Retrofit Cost Analyzer (multiplying the VOM $/ton cost by the ratio of the VOM cost for urea $/MWh to the total VOM cost $/MWh) results in a cost of around $500/ton of NO_X removed for the reagent cost alone.

EPA also estimated the cost of catalyst replacement and disposal in addition to the costs of reagent. EPA identified the cost for returning a partially operating SCR to full operation applying the Retrofit Cost Analyzer equations for all SCR-controlled coal-fired units that operated in 2021 in the United States on a per ton of NO_X removed basis. EPA updated the set of units based on the latest version of the NEEDS database (October 2021). This assessment covered 226 units.[4] EPA focused on a subset of 172 units that had minimum "input" NO_X emission rates of at least 0.14 lb/MMBtu).[5] Here, EPA defines the term "input" NO_X rate, or "uncontrolled" NO_X rate to be the emission rate of the unit following the combustion process including the effects of all existing combustion controls, measured after it has left the boiler, and where it would enter any post-combustion control equipment (if any). EPA used 0.14 lb/MMBtu because it found that, as described in the combustion control evaluation of this document (Figure C.3), that depending on unit type and fuel use, units emitting above that rate may have only state of the art combustion controls installed. Input NO_X rates below the 0.14 lb/MMBtu rate suggest that the SCR may have been operating to some extent, thereby biasing the cost estimates. EPA was able to identify the costs of each of the individual VOM and FOM cost components, including reagent, catalyst, and auxiliary fans and thereby, for each unit, to estimate the costs to fully optimize an SCR assuming it is currently operating to some extent and to restart and fully optimize an SCR assuming it currently has been idled. Some of these expenses, as modeled by the Retrofit Cost Analyzer, vary depending on factors such as unit size, NO_X generated from the combustion process, and reagent utilized. The EPA performed multiple assessments with this tool's parameters to investigate sensitivity relating to cost per ton of NO_X removed. Additionally, the agency modeled costs with urea, the higher-cost reagent for NO_X mitigation (and the reagent included in the Retrofit Cost Analyzer equations). The key input parameters in the cost equations are the size of the unit, the "input" NO_X rate, the NO_X removal efficiency, the type of coal, and the capacity factor.

In the analysis, we assumed these units burned the coal identified for the given unit in the NEEDS database at a 56% capacity factor.[6] We assumed that the SCRs operate with the NO_X removal efficiency needed for them to achieve the lower of their 2021 ozone season NO_X rate or the coal steam SCR optimized ozone season rate starting from the highest monthly NO_X rate for the time-period 2009-2021. This was selected as the "controlled" rate because it represented consistent and efficient operation of the

[4] See the "NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx.

[5] A NO_X emission rate at or above 0.2 lb/MMBtu, and possibly as low as 0.14 lb/MMBtu for some plant configurations, may be indicative of emissions from units where the SCR is not operating at all (See the discussion about state-of-the-art combustion controls).

[6] EPA evaluated costs of SCR operation at coal steam units utilizing the fleet wide coal steam capacity factor value projected in the 2030 run year of the IPM Summer 2021 Reference Case

unit's SCR. For the input NO_X rate, to identify an emission rate when the unit's SCR was not operating, we identified each unit's maximum monthly emission rate from the period 2009-2021. [7]

To estimate the cost to return a partially operating SCR to full operation, EPA examined only the sum of the VOM reagent and catalyst cost components and for these units, EPA ranked the quantified VOM costs for each unit and identified the cost at the 90th percentile level rank, which rounded to \$900/ton of NO_X removed. EPA selected the \$900/ton value because a substantial portion of units had combined reagent and catalyst costs at or less than this value of NO_X removed.

To estimate the cost to restart and fully optimize an idled SCR, EPA ranked the sum of the VOM and FOM costs for each unit and identified the 90th percentile cost. When rounded, this was \$1,700/ton of NO_X removed. EPA also identified the emission weighted average cost, which also rounded to \$900/ton of NO_X removed.

To further evaluate the costs for returning a partially operating control to full operation and for restarting a unit with an idled SCR, EPA applied the Retrofit Cost Analyzer equations for two "typical" units with varying input NO_X rates in a bounding analysis. The EPA used this to identify reasonable high and low per-ton NO_X control costs from reactivating an existing but idled SCR across a range of potential input NO_X rates.[8] For a hypothetical 500 MW unit with a relatively high input NO_X rate (e.g., 0.4 lb NO_X/MMBtu, 80% removal efficiency, 56% capacity factor, and 10,000 Btu/kWh heat rate), The urea and catalyst costs were around \$660/ton. The full VOM and FOM costs associated with restarting an idled control were around \$950/ton of NO_X removed. Conversely, a unit with a lower input NO_X rate (e.g., 0.14 lb NO_X/MMBtu and 60% removal) experienced a higher cost range revealing a urea and catalyst cost of \$1,150/ton. The full VOM and FOM costs associated with restarting an idled control were around \$2,220/ton of NO_X removed.

Considering the fleetwide assessment and the bounding analysis, for coal-steam units with SCR, EPA concludes that \$900/ton NO_X removed represents a reasonable estimate of the cost for operating SCR post-combustion controls on coal steam units that are already operating to some extent based on current market prices and typical operation.

Considering the fleetwide assessment and the bounding analysis, for coal-steam units with SCR, consistent with the cost level used in the RCU, the EPA concludes that a cost of \$1,600/ton of NO_X removed is a representative cost for the point at which restarting and fully operating idled SCRs becomes widely available to EGUs. EPA notes that the majority of units identified as having SCR optimization potential are already partially operating and best reflected by the \$900/ton optimization cost for partially operating units rather than this \$1,600/ ton cost for fully idled units.

Oil/Gas Steam:

For existing oil/gas steam units with existing SCR controls, EPA conducted a similar fleetwide assessment to that done for coal-steam units using the Retrofit Cost Analyzer.[9] We assumed these units burned the fuel identified in the NEEDS database at a 26% capacity factor.[10] We assumed that the SCRs

[7] For units where controls have always operated year-round, this method will likely underestimate the input NO_X rate.
[8] For these hypothetical cases, the "uncontrolled" NO_X rate includes the effects of existing combustion controls present (e.g., low NO_X burners).
[9] See the "NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx.
[10] EPA evaluated costs of SCR operation at oil/gas steam units utilizing the fleet wide oil/gas steam capacity factor value projected in the 2030 run year of the IPM Summer 2021 Reference Case which was 26%.

operate with the NO_X removal efficiency needed for them to achieve the lower of their 2021 ozone season NO_X rate or the oil/gas steam SCR optimized ozone season rate starting from the highest monthly NO_X rate for the time-period 2009-2021. This was selected as the "controlled" rate because it represented consistent and efficient operation of the unit's SCR. For the input NO_X rate, to identify an emission rate when the unit's SCR was not operating, we identified each unit's maximum monthly emission rate from the period 2009-2021.[11]

To estimate the cost to return a partially operating SCR to full operation we examined only the sum of the VOM reagent and catalyst cost components, while to assess the costs to restart and fully optimize an idled SCR the full VOM and FOM costs were assessed. In this section, from the full set of existing oil/gas steam unit, we focused on a subset of 16 units (of 20 existing oil/gas steam units with SCR) that had minimum "input" NO_X emission rates of at least 0.14 lb/MMBtu. EPA ranked the quantified VOM costs for each unit and identified the cost at the 90th percentile level rank, which rounded to \$500/ton of NO_X removed.

To estimate the cost to restart and fully optimize an idled SCR, EPA ranked the sum of the VOM and FOM costs for each unit and identified the 90th percentile cost. When rounded, this was \$1,000/ton of NO_X removed. We also identified an emission weighted average cost of \$700/ton. EPA concludes that \$500/ton is a representative cost for units to optimize an SCR for an oil/gas steam unit that is currently operating its control to some extent while \$700/ton NO_X removed is a representative cost to restart an idled SCR on oil/gas steam units based on current market prices and typical operation.

Combined Cycle and Combustion Turbine:

Considering SCR controls for other types of units (i.e., combined cycle and combustion turbines), EPA notes that these units would have similar operational costs to oil/gas steam units because most of the additional cost would be for reagent, which is directly proportional to the number of tons removed. Consequently, the costs to fully optimize an SCR that is already operating to some extent and the cost to restart and fully optimize an idled SCR would be comparable to that for oil/gas steam.

Summary:

Thus, considering the cost estimates for coal, oil/gas steam, combined cycle, and combustion turbines, EPA concludes that \$900/ton NO_X removed represents a reasonable (and likely a conservative) estimate that encompasses the cost for fully operating SCR controls that are current operating to some extent across all affected EGU types based on current market prices and typical operation. Similarly, for coal-steam, oil/gas steam units, combined cycle units, and combustion turbines the costs to restart and fully operate existing idled SCRs is typically less than \$1,600/ton. Thus, EPA conservatively assumes that all of these technologies will fully operate at this cost level.

In summary, EPA assumes that \$900/ton of NO_X removed is a broadly available cost point for units that currently are partially operating SCRs to fully operate their NO_X controls while \$1,600/ton of NO_X removed is a broadly available cost point for units to restart and fully operate existing idled SCR.

[11] For units where controls have always operated year-round, this method will likely underestimate the input NO_X rate.

2. NOX Emission Rate Estimates for Full Operation of Existing SCRs

Coal Steam:

EPA examined the ozone season average NO_X rates for 176 coal-fired units in the contiguous U.S. with an installed SCR over the time-period 2009-2021, then identified each unit's lowest, second lowest, and third-lowest ozone season average NO_X rate.[12] EPA updated the set of units based on the latest version of the NEEDS database (October 2021). EPA examined ozone season average NO_X rates from 2009 onwards as this year marks the point at which annual NO_X programs, rather than just seasonal programs, became widespread in the eastern US with the start of CAIR in 2009. EPA captured this dynamic with its baseline choice as this regulatory development could affect SCR operation (specifically, annual use of SCR means more frequent change of catalyst and relative difficulty with scheduling timing when the unit (or just the SCR) is not operating to allow for catalyst replacement and SCR maintenance).

The CSAPR Update and Revised CSAPR Update focused on the third-lowest ozone season NO_X rates achieved since 2009, reasoning that these emission rates are characteristic of a well-run and well-maintained system and achievable on a routine basis. At that time, 2019 represented the most recent year of full ozone-season data available. In the Revised CSAPR Update, EPA found that, between 2009 and 2019, EGUs on average achieved a rate of 0.079 lb NO_X/MMBtu for the third-lowest ozone season rate. Furthermore, EPA verified that in years prior to 2019, more than 95% of these same coal-fired units with identified optimization-based reduction potential in the Revised CSAPR Update had demonstrated and achieved a NO_X emission rate of 0.08 lb/MMBtu or less on a seasonal and/or monthly basis.[13] In the Revised CSAPR Update, EPA selected 0.08 lb NO_X/MMBtu as a reasonable representation for full operational capability of an SCR.

For this proposed rule, EPA utilizes the same rationale and methodology for identifying the rate that it did with the Revised CSAPR Update. As in prior rules, EPA assigns this rate as a "ceiling" on those units with SCR optimization potential, while generally assigning to SCR-equipped units emissions rates commensurate with actual historical performance. In other words, if an SCR-equipped EGU demonstrated achievement of an emission rate below 0.08 lb/MMBtu, that rate was assigned to the unit in the budget-setting process. EPA maintains that the timeline should include most-recent operational data (i.e., up through 2021) and continue to extend back to 2009. Considering the emissions data over the full time-period of available data that includes expected annual operation of SCRs at coal steam units (i.e., 2009-2021) results in an equal weighted unit-average third-best rate of 0.071 lb/MMBtu.[14] EPA notes that half of the EGUs achieved a rate of 0.064 lb NO_X/MMBtu or less over their third-best entire ozone season (see Figure B.1). EPA verified that in years prior to 2021, the majority (over 90%) of these same coal-fired units with identified optimization-based reduction potential in this rule had demonstrated and achieved a NO_X emission rate of 0.08 lb/MMBtu or less on a seasonal and/or monthly basis.[15]

After identifying this approach, the Agency examined each ozone season over the time period from 2009-2021 and identified the lowest monthly average NO_X emission rates for each year. Examining the third-lowest historical monthly NO_X rate, the EPA found that, on average EGUs achieved a rate of 0.062 lb NO_X/MMBtu. The third-lowest historical monthly NO_X rate analysis showed that a large proportion of units displayed NO_X rates below 0.08 lb/MMBtu (see Figure B.2).

[12] See "SCR_Historical_OS_Rates_2015proposal.xlsx" for details.
[13] See "Optimizing SCR Units with Best Historical NO_X Rates Final" in the docket for this rulemaking
[14] See "SCR_Historical_OS_Rates_2015proposal.xlsx" for details.
[15] See "Optimizing SCR Units with Best Historical NO_X Rates Updated to 2021" in the docket for this rulemaking

EPA also considered if the analysis should be specific to coal rank, among other factors. The average for bituminous coal units increased to 0.074 lb/MMBtu, while the average rate for subbituminous units decreased to 0.068 lb/MMBtu. These rates are relatively similar and therefore coal type is not an important factor when choosing a widely achievable NO_X rate for an optimized SCR on coal steam units.

Figure B.1. "Frequency" distribution plots for coal-fired units with an SCR showing their seasonal average NO_X emission rates (lb/MMBtu) during ozone seasons from 2009-2021. For each unit, the lowest, second lowest, and third lowest ozone season average NO_X rates are illustrated.

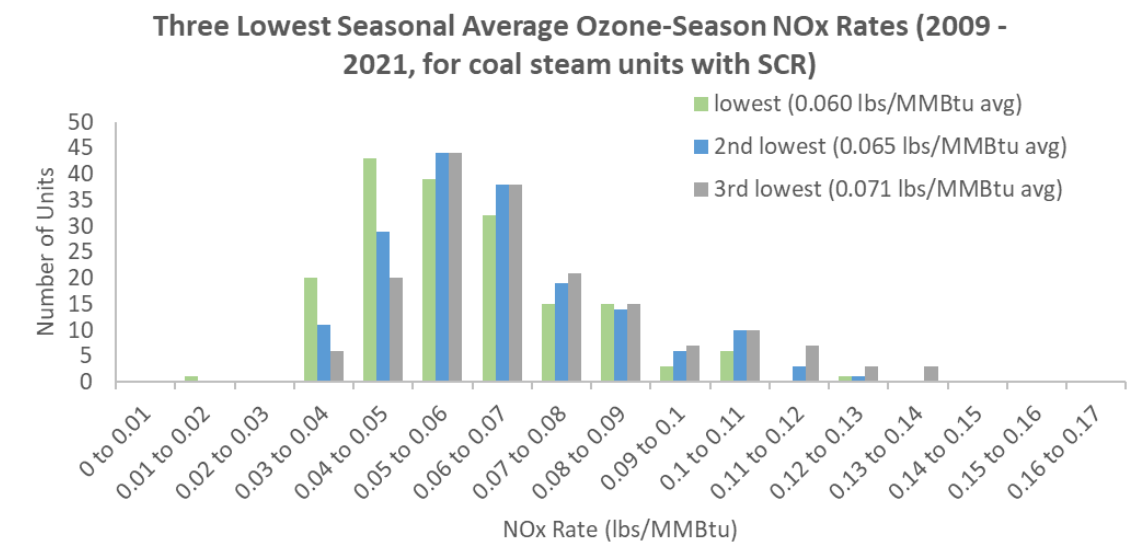
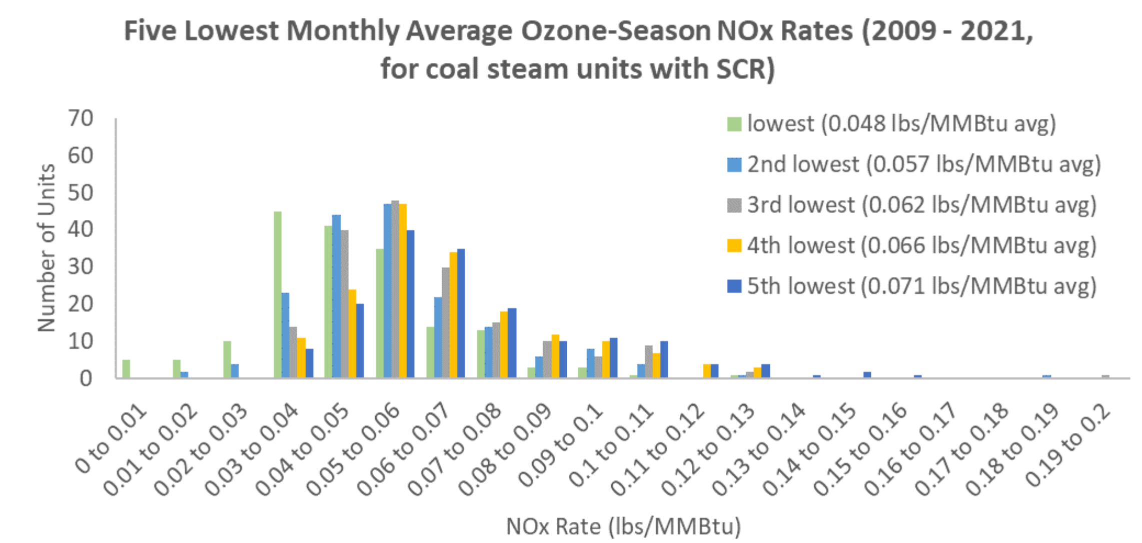
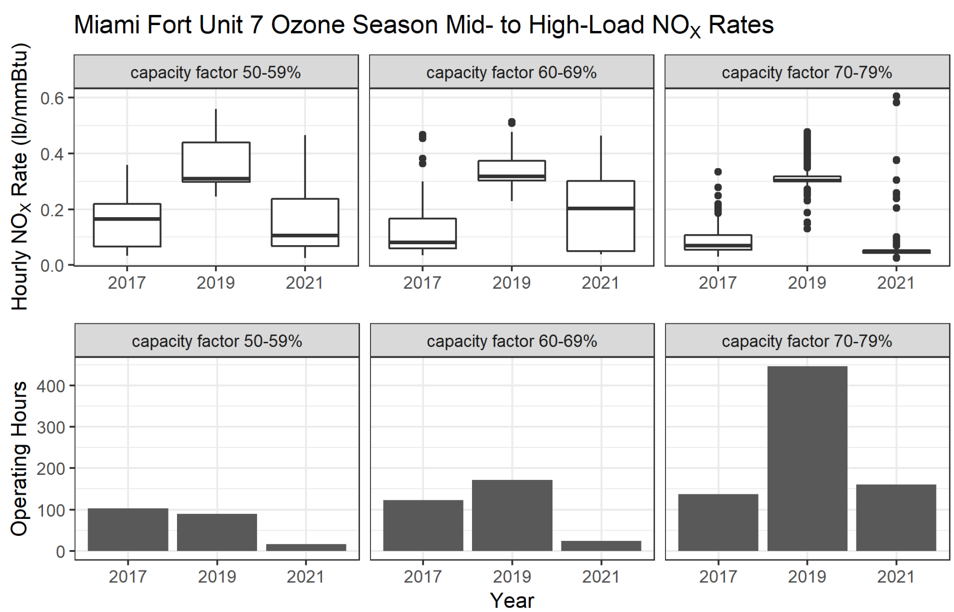


Figure B.2. "Frequency" distribution plots for coal-fired units with an SCR showing their monthly average NO_X emission rates (lb/MMBtu) during ozone seasons from 2009-2021. For each unit, the lowest, second lowest, third lowest, fourth lowest, and fifth lowest monthly average NO_X rates are illustrated.



Not only has the group of units with SCR optimization potential demonstrated they can perform at or better than the 0.08 lb/MMBtu rate on average, but more than 90 percent of the individual units in this group have met this rate on a seasonal and/or monthly basis based on their reported historical data. As an example, Miami Fort Unit 7 was able to improve the performance of the SCR at its coal unit (consistent with optimization assumptions) in the first year of CSAPR Update implementation (2017) and again in the first period of the Revised CSAPR Update implementation (2021) when the updated budgets created an incentive through higher allowance prices. (see Figure B.3)

Figure B.3. Example of Unit-level Emissions Rate Changes at a Given Capacity Factor Range.



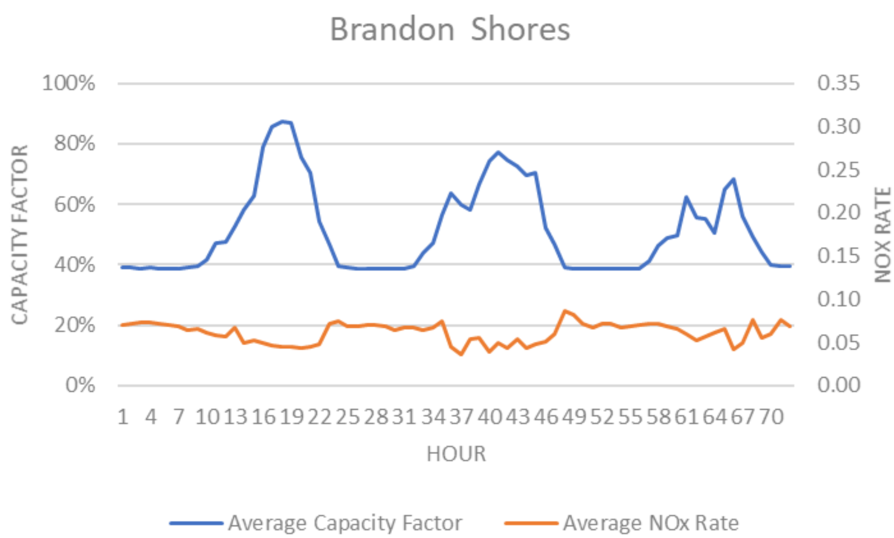
EPA observed this pattern in other units identified in this rulemaking as having significant SCR optimization emissions reduction potential. For instance, nearly 90% of the coal units identified as having reduction potential from its existing SCR in 2021 had operated at an emission rate lower than the 0.08 lb/MMBtu optimized rate in prior years. In the Emissions Data TSD for the supplemental notice that EPA recently released in a proceeding to address a recommendation submitted to EPA by the Ozone Transport Commission under CAA section 184(c), EPA noted, "In their years with the lowest average ozone season NO_X emissions rates in this analysis, these EGUs had relatively low NO_X emissions rates at mid- and high-operating levels; moreover, there was little variability in NO_X emissions rates at these operating levels. However, during the 2019 ozone season, these EGUs had higher NO_X emissions rates and greater variability in NO_X emissions rates across operating levels than in the past, particularly at mid-operating levels."[16]

Finally, some stakeholders have suggested that maintaining emissions rates characteristic of optimized SCR performance is difficult in an environment where coal units are dispatching less. EPA's review of hourly data indicates that maintaining consistent SCR performance at lower capacity factors is possible. For example, the unit-level performance data in Figure B.4 show the emissions rate at a plant, Brandon

[16] *See* "Analysis of Ozone Season NO_X Emissions Data for Coal-Fired EGUs in Four Mid-Atlantic States" (Docket #: EPA-HQ-OAR-2020-0351) available at https://www.regulations.gov/document/EPA-HQ-OAR-2020-0351-0004

Shores, staying relatively low (consistent with our optimization assumption of 0.08 lb/MMBtu) and stable across a wide range of capacity factors. The use of the fleetwide average rate computed using each unit's third best year to derive the SCR optimization rates further accommodates any heterogeneity in emissions rate that may stem from a unit's operational decisions such as capacity factor or coal-rank choice.

Figure B.4. Example of Consistently Low Unit-level Emissions Rate During Periods of Varying Capacity Factor



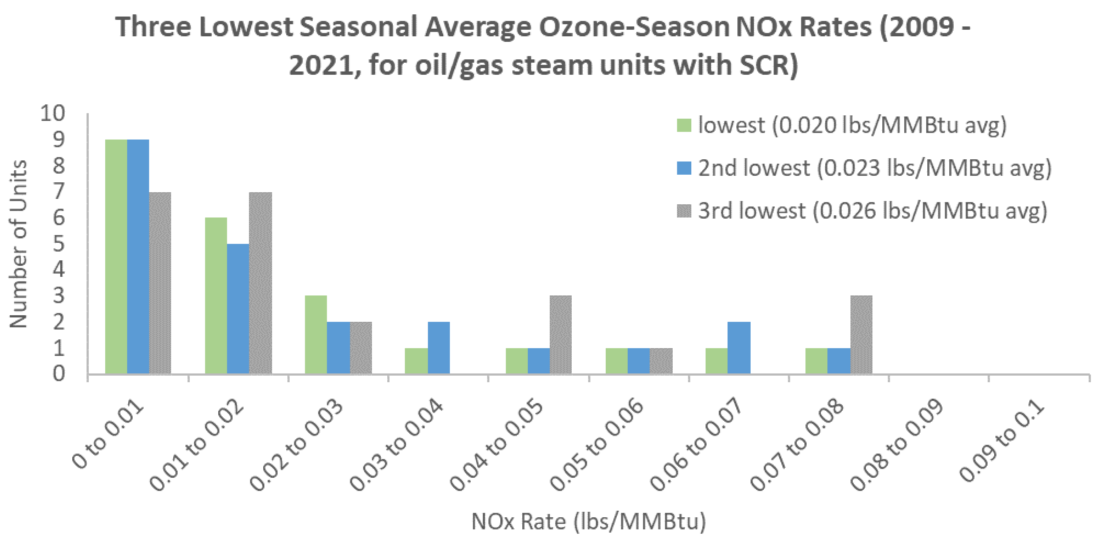
Based on all of the factors above, including the seasonal and monthly findings in Figures B.1 and B.2, the agency concludes an emission rate of 0.08 lb NO_X/MMBtu is widely achievable by the portion of the coal-fired EGU fleet with SCR optimization potential identified.

Oil/Gas Steam:

EPA conducted a similar analysis for oil/gas steam units. EPA examined the ozone season average NO_X rates for 23 oil/gas steam units in the contiguous U.S. with an installed SCR over the time-period 2009-2021 and calculated an equal weighted unit-average third-best rate of 0.03 lb/MMBtu.[17] EPA notes that half of these EGUs achieved a rate of 0.014 lb NO_X/MMBtu or less over their third-best entire ozone season (see Figure B.5). EPA verified that in years prior to 2021, the majority (approximately 60%) of these same oil/gas steam units with identified optimization-based reduction potential in 2021 data had demonstrated and achieved a NO_X emission rate of 0.03 lb/MMBtu or less on a seasonal and/or monthly basis; all such units had achieved a NO_X emission rate of 0.05 lb/MMBtu or less on a seasonal and/or monthly basis. Based on this analysis, the agency concludes an emission rate of 0.03 lb NO_X/MMBtu is widely achievable by the portion of oil/gas steam EGU fleet with SCR optimization potential identified.

[17] See "SCR_Historical_OS_Rates_2015proposal.xlsx" for details.

Figure B.5. Frequency distribution plots for oil/gas steam units with an SCR showing their seasonal average NO_X emission rates (lb/MMBtu) during ozone seasons from 2009-2021. For each unit, the lowest, second lowest, and third lowest ozone season average NO_X rates are illustrated.

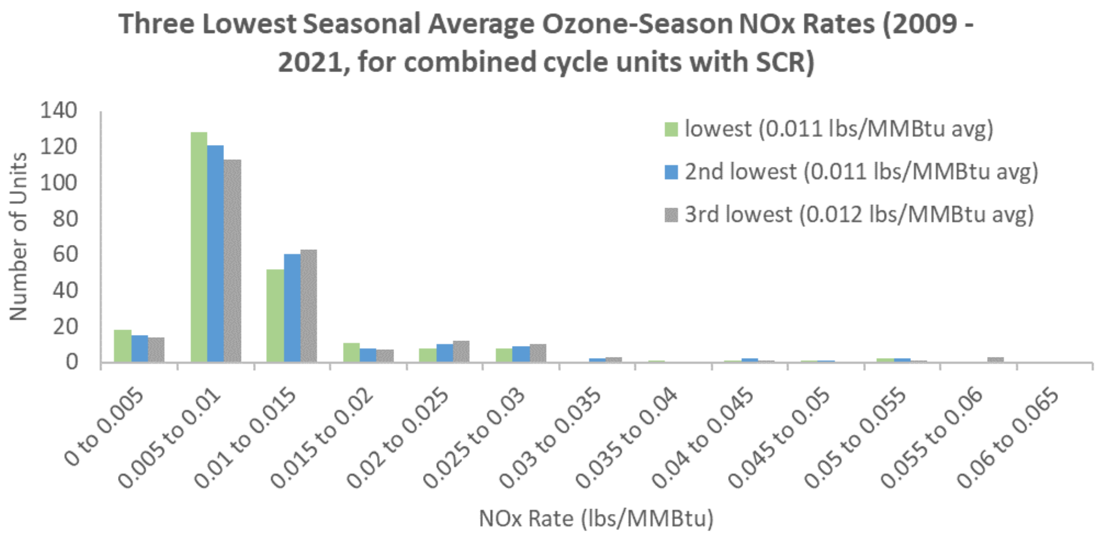


Combined Cycle:

EPA conducted a similar analysis for combined cycle units. EPA examined the ozone season average NO_X rates for 853 combined cycle units in the contiguous U.S. with an installed SCR over the time-period 2009-2021 and calculated an equal weighted unit-average third-best rate of 0.012 lb/MMBtu.[18] EPA notes that half of the combined cycle units achieved a rate of 0.009 lb NO_X/MMBtu or less over their third-best entire ozone season (see Figure B.6). EPA verified that in years prior to 2021, the majority (approximately 50%) of these same combined cycle units with identified optimization-based reduction potential in 2021 data had demonstrated and achieved a NO_X emission rate of 0.012 lb/MMBtu or less on a seasonal and/or monthly basis; all such units had achieved a NO_X emission rate of 0.066 lb/MMBtu or less on a seasonal and/or monthly basis. Based on this analysis, the agency concludes an emission rate of 0.012 lb NO_X/MMBtu is widely achievable by the portion of combined cycle EGU fleet with SCR optimization potential identified.

[18] See "SCR_Historical_OS_Rates_2015proposal.xlsx" for details.

Figure B.6. Frequency distribution plots for combined cycle units with an SCR showing their seasonal average NO_X emission rates (lb/MMBtu) during ozone seasons from 2009-2021. For each unit, the lowest, second lowest, and third lowest ozone season average NO_X rates are illustrated.



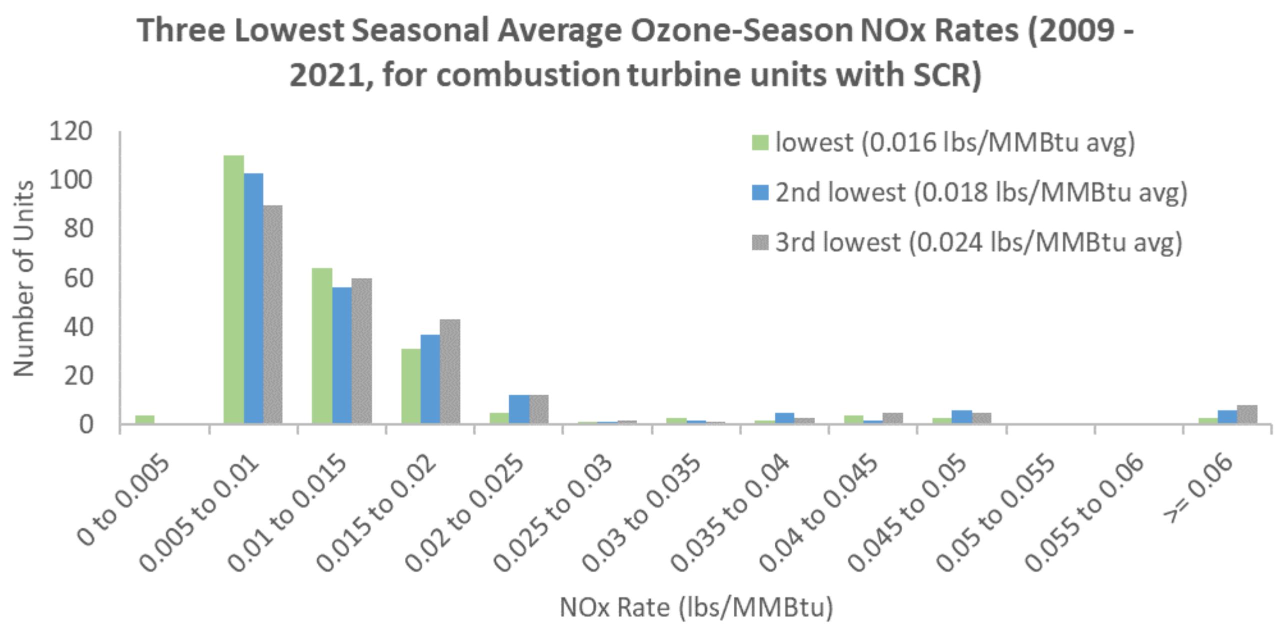
Combustion Turbine:

EPA conducted a similar analysis for combustion turbine units. EPA examined the ozone season average NO_X rates for 316 combustion turbine units in the contiguous U.S. with an installed SCR over the time-period 2009-2021 and calculated an equal weighted unit-average third-best rate of 0.024 lb/MMBtu.[19] EPA notes that half of the EGUs achieved a rate of 0.012 lb NO_X/MMBtu or less over their third-best entire ozone season (see Figure B.7). EPA verified that in years prior to 2021, the majority (approximately 60%) of these same combustion turbine units with identified optimization-based reduction potential in 2021 data had demonstrated and achieved a NO_X emission rate of 0.03 lb/MMBtu or less on a seasonal and/or monthly basis; all but one of such units had achieved a NO_X emission rate of 0.015 lb/MMBtu or less on a seasonal and/or monthly basis. Based on this analysis, the agency concludes an emission rate of 0.03 lb NO_X/MMBtu is widely achievable by the portion of combustion turbine EGU fleet with SCR optimization potential identified.[20]

[19] See "SCR_Historical_OS_Rates_2015proposal.xlsx" for details.

[20] EPA observes that updating the inventory of units to reflect recent retirements and most recent year data (e.g., 2009-2021) further supports EPA's 0.03 lb/MMBtu viability as a performance assumption and would in fact provide a lower value of 0.024 lb/MMBtu. This value is lower than the 0.03 lb/MMBtu derived from the 2009-2019 period as it reflects 2020 data and also excludes the SCR performance of since retired oil/gas steam units with SCRs. However, 2020 was not a representative year of unit dispatch and grid dynamics as changes in the first part of the ozone season related to shut downs had a significant influence on both unit operation and, in some cases, the resulting emission rate. Additionally, several units retired or did not operate after 2019, leading to the lower estimate of 0.024 lb/MMBtu when not factored into the inventory. However, these retirements do not obviate the usefulness of the unit's prior data for assessing technology performance in this case. Consequently, EPA is proposing the value of 0.03 lb/MMBtu identified using a timeframe that ends in 2019.

Figure B.7. Frequency distribution plots for combustion turbine units with an SCR showing their seasonal average NO_X emission rates (lb/MMBtu) during ozone seasons from 2009-2021. For each unit, the lowest, second lowest, and third lowest ozone season average NO_X rates are illustrated.



C. Installing State-of-the-Art Combustion Controls

1. Cost Estimates for State-of-the-Art Combustion Control Upgrade

Combustion control technology has existed for many decades. The technology generally limits NO_X formation during the combustion process by extending the combustion zone. Over time, as the technology has advanced, combustion controls have become more efficient at achieving lower NO_X rates than those installed years ago. Modern combustion control technologies routinely achieve rates of 0.20 – 0.25 lb NO_X/MMBtu and, for some units, depending on unit type and fuel combusted, can achieve rates below 0.16 lb NO_X/MMBtu. Figure C.1 shows average NO_X rates from coal-fired units with various combustion controls for different time periods.

Figure C.1. Ozone Season NO_X Rate (lb/MMBtu) Over Time for Coal-fired Units with Various Combustion Controls*

NO_X Control Technology	For 2003 – 2008 **NO_X Rate (lb/MMBtu)**	For 2003 – 2008 **Number of Unit-Years**	For 2009-2020 **NO_X Rate (lb/MMBtu)**	For 209-2020 **Number of Unit-Years**	For 2021 **NO_X Rate (lb/MMBtu)**	For 2021 **Number of Unit-Years**
Overfire Air	0.384	476	0.291	647	0.260	17
Low NO_X Burner Technology (Dry Bottom only)	0.351	1,062	0.266	1,208	0.217	32
Low NO_X Burner Technology w/ Overfire Air	0.306	464	0.225	742	0.203	29
Low NO_X Burner Technology w/ Closed-coupled OFA	0.266	341	0.219	361	0.162	14
Low NO_X Burner Technology w/ Separated OFA	0.222	451	0.187	635	0.151	24
Low NO_X Burner Technology w/ Closed-coupled/Separated OFA	0.207	460	0.166	886	0.138	52

* Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2021

Current combustion control technology reduces NO_X formation through a suite of technologies. Whereas earlier generations of combustion controls focused primarily on either Low NO_X Burners (LNB) or Overfire Air (OFA), modern controls employ both, and sometimes include a second, separated overfire air system. Further advancements in fine-tuning the burners and overfire air system(s) as a complete assembly have enabled suppliers to obtain better results than tuning individual components. For this proposed rule, the agency evaluated EGU NO_X reduction potential based on upgrading units to modern combustion controls. Combustion control upgrade paths are shown in Table 3-14 of the IPM version 6 Summer 2021 Reference Case documentation (*see* Chapters 3 and 5 of the IPM documentation for additional information, and Table 2b below).[21] The fully upgraded configuration for units with wall-fired boilers is LNB with OFA. For units with tangential-fired boilers, the fully upgraded configuration is LNC3 (Low NO_X burners with Close-Coupled and Separated Overfire Air). For each unit, EPA's understanding of the current NO_X control configuration can be found in the "NO_X Comb Control" column of the NEEDS v6 () database file.[22] EPA identified whether a unit has combustion control upgrade potential by comparing the Mode 1 NO_X Rate (lb/MMBtu) with the Mode 3 NO_X Rate (lb/MMBtu) within NEEDS. If the Mode 3 value is lower than the Mode 1 value, then the unit's combustion control configuration does not match the state-of-the-art configuration outlined in Figure C.2. For these units, EPA assumed a combustion control upgrade is possible based on the technology configurations identified in the NO_X post combustion control column.

[21] https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case
[22] See the NEEDS v.6 data file available in the docket and for download at https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6

With the wide range of LNB configurations and furnace types present in the fleet, the EPA decided to assess compliance costs based on an illustrative unit.[23] The agency selected this illustrative unit because its attributes (e.g., size, input NO_X emission rate) are representative of the EGU fleet, and, thus, the cost estimates are also representative of the EGU fleet. The EPA estimated costs for various combustion control paths. The cost estimates utilized the equations found in Table 5-4 "Cost (2016$) of NO_X Combustion Controls for Coal Boilers (300 MW Size)" from Chapter 5 of the IPM 5.13 documentation.[24] For these paths, EPA found that the cost ranges from $450 to $1,220/ton NO_X removed ($2011). EPA examined slightly lower capacity factors (i.e., 70%) and found the costs increased, to a range of $550 to $1,460/ton. At lower capacity factors (i.e., 56%), costs increased to a maximum of $1,800/ton for one type of installation. Examining the estimates for all the simulations, the agency finds that the costs of combustion control upgrades for units operating in a baseload fashion are typically comparable to the costs for returning a unit with an inactive SCR to full operation (i.e., $1,600/ton). Consequently, EPA identifies $1,600/ton as the cost level where upgrades of combustion controls would be widely available.

2. NO_X Emission Rate Estimates for State-of-the-Art Combustion Control Upgrade

EPA derived its performance rate assumptions for combustion control upgrade from an assessment of historical data where EPA reviewed similar boiler configurations with fully upgraded combustion controls and their resulting emission rates. Specifically, EPA examined two types of coal steam units: 1) dry-bottom wall-fired boilers and 2) tangentially-fired boilers. EPA looked at the current rate of existing units of each firing configuration and that already had state-of-the-art combustion controls (SOA CC). EPA estimated the average 2021 ozone season NO_X emission rates for all such units by firing type. EPA did not include any units that had post-combustion controls installed as their historical rate would be indicative of not just combustion control potential, but also post-combustion control potential. For dry bottom wall-fired coal boilers with "Low NO_X Burner" and "Overfire," there were 34 units averaging 0.204 lb/MMBtu.[25] For tangentially-fired coal boilers with "Low NO_X Burner" and "Closed-coupled/Separated OFA," there were 48 units averaging 0.138 lb/MMBtu.

Next, EPA identified the current boiler type for each unit in the fleet. It then applied the information shown below in Figure C.2 regarding state-of-the-art configurations compared to that unit's reported combustion control figuration to determine whether the unit had combustion control upgrade potential. Starting with dry-bottom wall-fired boilers, EPA verified that the average performance rate identified above for this boiler configuration with state-of-the-art combustion controls 1) resulted in reductions consistent with the technology's assumed percent-reduction potential when applied to this subset of units,

[23] For this analysis, EPA assumed a 500 MW unit with a heat rate of 10,000 Btu/kWh and an 85% annual capacity factor. We assumed the unit was burning bituminous coal and had a NO_X rate of 0.50 lb NO_X / MMBtu initial rate based on its existing NO_X combustion controls and had a 42% NO_X removal efficiency after the combustion control upgrades. This 0.50 lb/MMBtu input NO_X rate is comparable to the observed average rate of 0.48 lb/MMBtu for the coal-fired wall-fired units from 2003-2008 that had not installed controls. There are very few remaining units that lack combustion controls. One unit had a rate higher than 0.5 lb/MMBtu. Using 2019 data for wall-fired coal units lacking combustion controls and comparing these rates against controlled units of the same type, EPA observes a 42% difference in rate. Similarly, EPA observes a 55% reduction for coal units with tangentially-fired boilers. Despite the very small numbers of remaining units that lack combustion controls, to be conservative, EPA used the 42% reduction from wall-fired coal units.

[24] Costs were converted to 2016$ from the tables original 2011 values.
https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_emission_control_technologies_0.pdf

[25] In past rulemakings, EPA found the representative rate for state-of-the-art combustion controls to be 0.199 lb/MMBtu. Thus, this analysis re-affirms EPA's selection of 0.199 lb/MMBtu as the representative rate for state-of-the-art combustion controls for most unit types.

and/or 2) had been demonstrated by both subbituminous and bituminous coal units with state-of-the-art combustion controls in its 2019 dataset. EPA found an assumed emission rate of 0.199 lb/MMBtu to be reasonable for dry-bottom, wall-fired boilers upgrading to state-of-the-art combustion controls.

EPA applied the same approach for tangentially-fired coal boilers. As shown in Figure C.3, this produced a weighted average assumed emission rate of 0.147 lb/MMBtu. However, EPA observed that in 2019 no bituminous burning units with this boiler type (and no post-combustion controls) had met the 0.147 lb/MMBtu average for this control configuration (which was heavily weighted by subbituminous units with such combustion controls) (see Figure C.3). It also noted that the 0.147 rate lb/MMBtu would imply a greater percent reduction for some bituminous units with upgrade potential than EPA identified as representative for the technology. Therefore, given these two findings and the bituminous orientation of the fleet with state-of-the-art combustion control upgrade potential covered in this action, EPA determined that the 0.199 lb/MMBtu was also appropriate for tangentially-fired units in this action as that rate satisfied both criteria.[26]

Figure C.2. State-of-the-Art Combustion Control Configurations by Boiler Type

Boiler Type	Existing NOx Combustion Control	Incremental Combustion Control Necessary To Achieve "State-of-the-Art"
Tangential Firing	Does not include LNC1 and LNC2	LNC3
Tangential Firing	Includes LNC1, but not LNC2	Conversion from LNC2 to LNC3
Tangential Firing	Includes LNC2, but not LNC3	Conversion from LNC1 to LNC3
Tangential Firing	Includes LNC1 and LNC2 or LNC3	-
Wall Firing, Dry Bottom	Does not Include LNB and OFA	LNB + OFA
Wall Firing, Dry Bottom	Includes LNB, but not OFA	OFA
Wall Firing, Dry Bottom	Includes OFA, but not LNB	LNB
Wall Firing, Dry Bottom	Includes both LNB and OFA	-

Note: Low LNB =NO_X Burner Technology, LNC1=Low NO_X coal-and-air nozzles with close-coupled overfire air, LNC2= Low NO_X Coal-and-Air Nozzles with Separated Overfire Air, LNC3 = Low NO_X Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air, OFA = Overfire Air

Figure C.3. 2019 average NOX rate for units with state-of-the-art combustion controls for tangentially-fired boilers (lb/MMBtu)

Coal Type	NO_X Rate (lb/MMBtu)
Bituminous	0.199
Bituminous, Subbituminous	0.172
Subbituminous	0.134
Weighted Average	**0.147**

[26] See the entry titled "State-of-the-art Combustion Control Data" in the docket for this rulemaking

D. Cost Estimates for Optimizing and Restarting and Optimizing Idled Existing SNCR

Coal Steam:

EPA sought to examine costs for full operation of SNCR. SNCR are post-combustion controls that reduce NO_X emissions by reacting the NO_X with either ammonia or urea, without catalyst. Because the reaction occurs without catalyst and is thereby a less efficient reaction, several times more reagent must be injected to achieve a given level of NO_X removal with SNCR than would be required to achieve the same level of NO_X removal with SCR technology. Usually, an SNCR system does not achieve the level of emission reductions that an SCR can achieve, even when using large amounts of reagent. For the SNCR analysis, as with the SCR analyses described above, the agency used the Retrofit Cost Analyzer equations to perform a bounding analysis for examining operating expenses associated with a "generic" coal steam unit returning an SNCR to full operation. EPA examined the costs to fully operate an SNCR that was already being operated to some extent and the costs to restart and fully operate an SNCR that had been idled.

Comparable to the discussion about fully optimizing an SCR, the cost to fully optimize an SNCR that is currently operating to some extent is the VOM costs for additional reagent (urea and steam). Reagent consumption represents the largest portion of the VOM cost component of unit operation and is directly related to NO_X removal. The other VOM components (e.g., to auxiliary power) as well as the FOM components are assumed to be largely indifferent to additional NO_X removal. For units with an idled, or mothballed, SNCR returning to full operation, the owner incurs the full suite of VOM and FOM costs.

For this bounding analysis, the agency examined two cases: first, a coal steam unit with a high input NO_X rate 0.40 lb/MMBtu; second, a coal steam unit with a lower input NO_X rate 0.20 lb /MMBtu – both assuming a 25% removal efficiency for NO_X.[27,28] For the high-rate unit case, VOM and FOM costs were calculated as approximately $2,100/ton NO_X with about $1,600/ton of that cost associated with urea use. For the low-rate unit case, VOM and FOM costs approached $3,500/ton NO_X with nearly $2,700/ton of that cost associated with urea procurement. Despite equivalent reduction percentages for each unit, the cost dichotomy results from differences in the input NO_X rates for the units and the type of boiler, resulting in a modeled step-change difference in urea rate (either a 15% or 25% reagent usage factor).

EPA also examined SNCR cost sensitivity by varying NO_X removal efficiency while maintaining the input NO_X emission rate. In this analysis, SNCR NO_X removal efficiency was assumed to be 40% for the first cost estimate and 10% for the second cost estimate. For a high-rate unit (with an input rate of 0.40 lb NO_X/MMBtu), the associated costs were $2,000/ton and $2,450/ton. For a low-rate unit (i.e., an input rate of 0.20 lb NO_X/MMBtu), the associated costs were $3,370/ton and $4,180/ton. These analyses together illustrate that SNCR costs on a dollar per ton basis are more sensitive to a unit's input NO_X rate than the potential NO_X removal efficiency of the SNCR itself.

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[27] For both cases, we examined a 500 MW unit with a heat rate of 10,000 Btu/kWh operated at a 26% annual capacity factor while burning bituminous coal. The capacity factor used was based on the IPM-estimated operation of units with SNCR. Furthermore, in the cost assessment performed here, the agency assumes SNCR NO_X removal efficiency to be 25%, which is consistent with the range of documented removal efficiency in IPM and historic data. See the Retrofit Cost Analyzer (Update 1-26-2022) tool and the "Coal-Fired SNCR Cost Methodology."

[28] *Steam; Its Generation and Use 41ed* (2005) J B Kitto; S C Stultz; Babcock & Wilcox Company, lists 20-30% conversion of NO_X as typical, with up to 50% possible under certain circumstances.

EPA conducted a fleetwide assessment of coal-fired units with existing SNCR (70 units total) using the same set of assumptions used for the fleetwide assessment for units with SCR (i.e., the method for determining input NO_X rate, NO_X removal efficiency, and capacity factor) using the Retrofit Cost Analyzer.[29] In that tool, we can examine the VOM and FOM cost components associated with operation of the unit to approximate costs of fully optimizing a currently operating control and to restart and fully optimize an idled control. Of the full set of units, 47 met the size and operating criteria set forth for SCR units (i.e., 100 MW in size or great, 0.14 lb/MMBtu input NO_X rate or greater, and at least some emission reduction). EPA found that the median cost to fully optimize a currently operating control is $1,600/ton while the cost to restart and fully optimize an idled control has a median cost of $3,500/ton and an emission weighted cost of $2,100/ton.

In the Revised CSAPR Update, EPA concluded that $1,800/ton was a representative cost for units that are currently operating their SNCR controls to some extent to fully operate those controls and $3,900/ton was a representative cost for units that had idled their SNCR controls. Based on the fleetwide analysis, the bounding analysis, and the Revised CSAPR Update analysis, EPA concludes that $1,800/ton is a representative cost to fully operate SNCR for units that are currently operating an SNCR to some extent and that a $3,900/ton cost is representative to turn on and fully operate controls for units whose SNCR control has been idled.

Finally, EPA assessed the existing fleet of units with SNCR technology to assess whether, or not, the units were typically operating their controls to some extent or whether the controls had been fully idled to assess whether the cost breakpoint level should be identified as $1,800/ton or $3,900/ton. EPA examined the fleet of coal-steam and oil/gas steam units that have SNCR optimization potential within the geography and assessed whether the units are currently partially operating but not necessarily optimizing their SNCRs or whether the units have idled their controls. EPA assessed whether SNCRs were partially operating or were idled doing a two-part analysis. First, EPA compared each unit's 2021 reported rate to this proposal's SNCR optimization emission rate for that unit. A difference less than 25% between reported and optimized NO_X rate for a given EGU is an indicator that its SNCR is already partially operating as of 2021 (as 25% NO_X removal is a representative average of what SNCRs may achieve when going from no operation to full operation).[30] To identify the optimized value for each unit and compare that to 2021 baseline emission rates, EPA utilized the mode 2 rate from the NEEDS database (October 2021). As described in EPA's power sector IPM Modeling Documentation (Chapter 3), these unit-specific NO_X mode rates are calculated from historical data and reflect operation of existing post-combustion controls.[31] Four modes are identified for each unit to, among other things, identify their emission rates with and without their post-combustion controls operating. Mode 2 for SNCR-controlled units is intended to reflect the operation of that unit's post combustion control based on prior years when that unit operated its control. The optimized SNCR emission rates assumed for each controlled unit are identifiable in the NEEDS file "Mode 2 NO_X rate (lb/MMBtu)" column.[32] If a unit's 2021 emission rate was at or lower than its "optimized" SNCR rate, than no additional reductions are expected from "optimizing" that unit's post-combustion control.

[29] See "NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx."
[30] "Coal-Fired SNCR Cost Methodology"
[31] https://www.epa.gov/system/files/documents/2021-09/chapter-3-power-system-operation-assumptions.pdf
[32] See the NEEDS v.6 data file available in the docket and for download at https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6

Comparing each unit's 2021 reported emissions rate to this proposal's SNCR optimization emission rate (see Figure D.1), the majority of affected EGUs with existing SNCR (44 of 49 units) have percent differences less than 25%, suggesting that their SNCRs appeared to be partially operating at least to some extent based on the first indicator alone. For the remaining 5 units, EPA compared the historical highest rate for each unit (dating back to 2009) to its 2021 reported emission rate. For two of the units, the reported 2021 rate was substantially lower than the unit's historical highest rate, so EPA assumes that the SNCR at these units were also operating to some extent in 2021. For the remaining units, either the SNCR has consistently been fully operating throughout the life of the unit (i.e., the time period of this analysis) or the control may have been idled. Between the two indicators, EPA determined that nearly all SNCRs with optimization potential were at least partially operating their controls during 2021. Consequently, EPA concludes that a VOM reagent-centric cost of $1,800/ton is a reasonable representative cost for emissions reductions for fully operating SNCR for units with this existing control.

Figure D.1. Ozone-season NO_X Emission Rates (lb/MMBtu) for Units with SNCR Reduction Potential

Facility	State	ORIS	Boiler	2021 OS NO_X Rate (lb/MMBtu)	SNCR Optimization OS Rate (lb/MMBtu)	Percent Change in Rate (2021 vs Optimized Rate)	Historical Max OS NO_X Rate (2009-2021)	Percent Change Between 2021 and Historical Max
Yorktown Power Station	Virginia	3809	3	0.13	0.02	86%	0.25	46%
Grant Town Power Plant	West Virginia	10151	1B	0.32	0.16	51%	0.35	7%
Grant Town Power Plant	West Virginia	10151	1A	0.33	0.16	50%	0.35	7%
Manitowoc	Wisconsin	4125	9	0.08	0.05	43%	0.09	10%
Brame Energy Center	Louisiana	6190	3-2	0.04	0.03	32%	0.07	38%
Seward	Pennsylvania	3130	2	0.12	0.09	24%		
Powerton	Illinois	879	61	0.11	0.08	20%		
Edge Moor	Delaware	593	4	0.05	0.04	20%		
Marion	Illinois	976	123	0.10	0.08	20%		
Brame Energy Center	Louisiana	6190	3-1	0.04	0.03	18%		
Powerton	Illinois	879	62	0.10	0.08	17%		
Sikeston	Missouri	6768	1	0.12	0.10	14%		
Whitewater Valley	Indiana	1040	1	0.32	0.28	13%		
Whitewater Valley	Indiana	1040	2	0.34	0.30	12%		
Grayling Generating Station	Michigan	10822	1	0.13	0.12	12%		
Twin Oaks	Texas	7030	U1	0.10	0.09	12%		
IPL - Harding Street Station (EW Stout)	Indiana	990	60	0.04	0.04	10%		
Limestone	Texas	298	LIM2	0.18	0.16	9%		
Sioux	Missouri	2107	1	0.25	0.23	9%		
Powerton	Illinois	879	51	0.11	0.10	9%		
Spruance Genco, LLC	Virginia	54081	BLR04A	0.03	0.03	8%		
Joliet 29	Illinois	384	82	0.10	0.09	8%		
Spruance Genco, LLC	Virginia	54081	BLR03A	0.03	0.03	7%		
Joliet 29	Illinois	384	81	0.10	0.09	7%		
Joliet 29	Illinois	384	71	0.08	0.08	7%		
Boswell Energy Center	Minnesota	1893	4	0.11	0.10	6%		
Twin Oaks	Texas	7030	U2	0.10	0.09	6%		
Spruance Genco, LLC	Virginia	54081	BLR04B	0.03	0.03	6%		
Altavista Power Station	Virginia	10773	2	0.12	0.12	6%		
Altavista Power Station	Virginia	10773	1	0.12	0.12	6%		
Joliet 29	Illinois	384	72	0.08	0.08	5%		
Southampton Power Station	Virginia	10774	1	0.13	0.12	4%		
Southampton Power Station	Virginia	10774	2	0.13	0.12	4%		
Barry	Alabama	3	4	0.27	0.26	4%		
San Miguel	Texas	6183	SM-1	0.16	0.16	3%		
Fort Martin Power Station	West Virginia	3943	1	0.29	0.28	3%		
Hopewell Power Station	Virginia	10771	1	0.12	0.12	3%		
Hopewell Power Station	Virginia	10771	2	0.12	0.12	3%		
AES Warrior Run	Maryland	10678	001	0.07	0.07	3%		
Seward	Pennsylvania	3130	1	0.11	0.11	3%		
Nacogdoches Generating Facility	Texas	55708	BFB-1	0.08	0.08	3%		
Sioux	Missouri	2107	2	0.23	0.22	3%		
New Castle	Pennsylvania	3138	4	0.07	0.07	1%		
Laramie River	Wyoming	6204	2	0.14	0.14	1%		
Edge Moor	Delaware	593	3	0.06	0.06	1%		
Clinch River	Virginia	3775	2	0.13	0.13	1%		
Big Cajun 2	Louisiana	6055	2B3	0.12	0.12	0%		
New Castle	Pennsylvania	3138	3	0.07	0.07	0%		
Rothschild Biomass Cogeneration Facility	Wisconsin	58124	1	0.08	0.08	0%		

Oil/Gas Steam:

Using the Retrofit Cost Analyzer, the agency conducted a bounding analysis to assess the costs for optimizing Oil/Gas steam units that are not fully operating their controls and/or restarting and optimizing idled SNCR controls. Again, assuming a 25% reduction in emission rate and for a unit similar to that examined above for coal steam units (500 MW, tangential boiler, input NO_X rate of 0.2 lb NO_X/MMBtu, 10,000 Btu/kWh heat rate, with a 25% NO_X removal efficiency) using natural gas with a 26% capacity factor, the VOM and FOM costs were calculated as approximately $3,500/ton NO_X with about $2,700/ton of that cost associated with urea use. These costs are not particularly sensitive to the capacity factor of the unit, with the urea-use cost insensitive to unit usage. The costs were also largely indifferent to the selection of gas compared with oil. For the same unit, but with a lower input NO_X rate of 0.14 lb/MMBtu, the VOM+FOM costs increased to $3,600/ton while the urea cost remained at $2,700/ton. For the same unit, but with a higher input NO_X rate of 0.4 lb/MMBtu, the VOM+FOM costs decreased to $2,000/ton while the urea cost dropped to $1,600/ton.

EPA also conducted a similar fleetwide analysis for oil/gas steam units with existing SNCR, which included 22 units, 21 of which met the size and operating criteria (i.e., 100 MW in size or great, 0.14 lb/MMBtu input NO_X rate or greater, and at least some emission reduction).[33] EPA found that the median cost to fully optimize a currently operating control is $1,600/ton while the cost to restart and fully optimize an idled control has a median cost of $1,900/ton and an emission weighted cost of $2,000/ton.

Based on the fleetwide analysis and the bounding analysis, EPA estimates that $1,600/ton is a representative cost to fully operate SNCR for oil/gas steam units that are currently operating an SNCR to some extent and that a $3,500/ton cost is representative to turn on and fully operate SNCR for oil/gas steam units whose control has been idled.

Summary:

EPA finds that $1,800/ton is a representative cost to fully operate SNCR for both coal and oil/gas steam units that are currently operating an SNCR to some extent and that a $3,900/ton cost is representative to turn on and fully operate controls for SNCR units whose controls have been idled.

E. Cost and Emission Rate Performance Estimates for Retrofitting with SNCR and Related Costs

SNCR technology is an alternative method of NO_X emission control that incurs a lower capital cost compared with an SCR, albeit at the expense of greater operating costs and less NO_X emission reduction. Some units with anticipated shorter operational lives or with low utilization may benefit from this control technology. The higher cost per ton of NO_X removed reflects this technology's lower removal efficiency which necessitates greater reagent consumption, thereby escalating VOM costs. The agency examined the costs of retrofitting coal steam and oil/gas steam units with SNCR technology using the Retrofit Cost Analyzer. The agency did not consider retrofitting SNCR on combustion turbine or combined cycle units as, except for a single combustion turbine at the Delaware City Plant, there are no EGUs of these plant types in NEEDS equipped with SNCR.

[33] See the "NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx.

Coal Steam:

For SNCR retrofits on coal steam units, the agency conservatively set the NO_X emission reduction rate at 25% – the same assumption used in the Revised CSAPR Update Rule and in EPA's power sector modeling.[34] For a similar illustrative unit examined for combustion control upgrades (500 MW, tangential boiler, 10,000 Btu/kWh heat rate, bituminous fuel) and input emission rate of 0.2 lb NO_X/MMBtu, with a capacity factor of 56%, the cost is $6,200/ton.[35] When the capacity factor is 26%, the costs increase to $9,700/ton. At a higher capacity factor (i.e., 80%), the costs decrease, going to $5,300/ton, respectively. Next, EPA examined the cost of SNCR installation at small units (25 MW and 100 MW in size). The costs at the three capacity factors (26%, 56%, and 80%) for the 25 MW unit were $38,300/ton, $19,500/ton, and $14,600/ton. The costs for the 100 MW unit at the three capacity factors (26%, 56%, and 80%)[36] were $19,300/ton, $10,700/ton, and $8,400/ton.

Next, using a similar set of assumptions as in the previous paragraph (i.e., type of coal and capacity factor),[37] EPA examined the remaining coal-fired fleet that lack SNCR or other NO_X post-combustion control to estimate an emission weighted average and median cost of SNCR installation (on a $/ton basis) using the Retrofit Cost Analyzer.[38] In this case the input NO_X rate was the 2023 baseline NO_X rate engineering analysis rate (see Section B in the Ozone Transport Policy Analysis Proposed Rule TSD for details) and the "controlled" NO_X rate was usually the input NO_X rate reduced by 25% (circulating fluidized bed boilers were assigned reductions of 50%). Costs were estimated for units that had a minimum input NO_X rate of at least 0.14 lb/MMBtu. In this instance, the emission weighted average cost is $6,000/ton and the median value is $6,300/ton. EPA repeated these calculations for the subset of coal-fired units less than 100 MW and found an emission weighted average cost of $6,700/ton and a median value of $9,600/ton.[39]

EPA also looked at the size of coal steam units that had a SNCR or SCR. Looking at the existing coal fleet in NEEDS for the Summer 2021 Reference Case, there are 146 GW (318 units) with a NO_X post-combustion control: 25 GW (91 units) with SNCR and 121 GW (227 units) with SCR. There are approximately 52 GW of coal units without a NO_X post-combustion control. The average size of units with SNCR or SCR is about 275 MW and 530 MW, respectively, indicating that not only is SCR a more common NO_X post-combustion control, covering about 60% of the coal fleet capacity, but also that it tends to be installed on larger coal-fired units. Looking at the subset of units with post-combustion controls that are less than 100 MW, EPA found that post-combustion controls favored SNCR. There are 30 such units with SNCR and 4 with SCR, indicating that SNCR seems to be the overwhelming choice of NO_X post-combustion control for smaller units. Finally, EPA notes SNCR retrofits on coal steam units

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[34] "Coal-Fired SNCR Cost Methodology"

[35] The input emission rate for a tangentially-fired unit with bituminous coal and state of the art combustion controls is 0.2 (see Figure C.3).

[36] These capacity factors were chosen because they provide a wide range of capacity factors. Furthermore, 26% and 56% are the operating fleet-wide oil-gas steam and coal steam unit capacity factors in 2030 in the Summer 2021 IPM Reference Case, and therefore represent the projected average capacity factor for those plant types.

[37] Units were assumed to use the coal identified in NEEDS, were assumed to operate the control throughout the year, and were assumed to have a capacity factor of 56%.

[38] See the Excel file NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx for additional details.

[39] See the NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx for details.

have a decreasing removal efficiency as unit size increases, which further explains the observed prevalence on smaller units.[40]

Oil/Gas Steam:

Using the Retrofit Cost Analyzer, the agency conducted a similar analysis for SNCR retrofit on Oil/Gas Steam units, again assuming a 25% reduction in emission rate.[41] For a unit similar to that examined above for coal steam units (500 MW, tangential boiler, 0.2 lb NO_X/MMBtu, 10,000 Btu/kWh heat rate, with a 25% NO_X removal efficiency) using natural gas with a 26% capacity factor, the cost is $8,400/ton of NO_X removed. At a capacity factor of 56%, the cost is $5,600/ton. At higher capacity factors (i.e., 80%), the costs decrease, going to $4,900/ton. The costs were largely indifferent to the selection of gas compared with oil. For the same unit, but with a lower starting NO_X rate of 0.14 lb/MMBtu, the costs at the three capacity factors increased to $10,500, $6,600, and $5,600/ton. Next, EPA examined the cost of SNCR installation at small units (25 MW and 100 MW in size with an input NO_X rate of 0.2 lb/MMBtu). The costs at the three capacity factors (26%, 56%, and 80%) for the 25 MW unit were $31,400/ton, $16,200/ton, and $12,300/ton, respectively. The costs for the 100 MW unit were $16,100/ton, $9,200/ton, and $7,400/ton, respectively.

Finally, using a similar method for determining an input NO_X rate and a NO_X removal efficiency described above for coal steam units, EPA examined the remaining oil/gas steam fleet that lack SNCR or other NO_X post-combustion control to estimate an emission weighted average and median cost of SNCR installation (on a $/ton basis) using the Retrofit Cost Analyzer.[42] Costs were estimated for units that had a minimum input NO_X rate of at least 0.14 lb/MMBtu and had a three-year average (2019-2021) of at least 150 tons of ozone season NO_X (i.e., approximately 1 ton per day during the ozone season). Units were assumed to have a NO_X removal rate of 25% and assumed to operate the control throughout the year and had an assumed capacity factor of 26% (the fleet-wide oil/gas steam capacity factor from the Summer 2021 IPM reference case). In this instance, the emission weighted average cost is $8,600/ton and the median value is $9,600/ton.

F. Cost and Emission Rate Performance Estimates for Retrofitting with SCR and Related Costs

For coal-fired and oil/gas steam units, an SCR retrofit is the state-of-the-art technology used to achieve the greatest reductions in NO_X emissions. The agency examined the cost for newly retrofitting a unit with SCR technology. Based on the updated Retrofit Cost Analyzer,[43] EPA assumed a new state-of-the-art SCR retrofit could achieve 0.05 lb/MMBtu emission rate[44] performance on a coal steam unit (regardless

[40] See Table 5-4 in the Documentation for EPA's IPM Summer 2021 Reference Case.
[41] "Gas-Fired SNCR Cost Methodology"
[42] See the NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx for details
[43] See the Retrofit Cost Analyzer (Update 1-26-2022)
[44] In prior modeling used for CSAPR rulemakings, EPA had assumed new SCR retrofits could achieve a 0.07 lb/MMBtu NO_X emission rate for bituminous coal and 0.05 lb/MMBtu for other coal rank (e.g., subbituminous). EPA had previously highlighted the upper end of this range as a representative rate based on the achievable NO_X

of type of coal used) and 0.03 lb/MMBtu for an oil-/gas steam unit. The same assumption was used in the EPA's power sector modeling for this proposed rule. Historically, many coal-fired units with SCR retrofits after 2010 achieved NO_X emission rates near or below 0.05 lb/MMBtu, further supporting that new SCRs can achieve such an emission rate. Additionally, most oil/gas steam units equipped with SCR have achieved NO_X emission rates under 0.03 lb/MMBtu.

Coal Steam:

To understand the effect of input NO_X rate on costs, using the Retrofit Cost Analyzer equations, the EPA performed a bounding analysis to identify reasonable high and low per-ton NO_X control costs for adding SCR post-combustion controls across a range of potential input NO_X rates.[45] For a hypothetical unit 500 MW in size with a relatively low input NO_X rate (e.g., 0.2 lb NO_X/MMBtu, bituminous fuel, 2 lb SO_2/MMBtu, 60% removal efficiency, 56% capacity factor, and 10,000 Btu/kWh heat rate), the capital cost was about $151,000,000. For a similar unit with an input NO_X rate of 0.4 lb/MMBtu and 80% NO_X removal efficiency, the total capital cost was $160,000,000. The cost on a per-ton basis varies with the assumptions concerning the operation of the unit and the book life of the loan (or lifetime of the equipment). Assuming an annual capital recovery factor of 0.143, NO_X rate of 0.2 lb/MMBtu and removal efficiency of 60% and annual operation, the cost per ton was $16,400/ton ($14,700/ton for the capital cost, $300/ton for the FOM cost, and $1,400/ton for the VOM cost). For the unit with the NO_X rate of 0.4 lb/MMBtu and removal efficiency of 80%, the costs were $6,800/ton ($5,800/ton for the capital cost, $100/ton for the FOM cost, and $850/ton for the VOM cost).

For this proposed rule, EPA examined the remaining coal-fired fleet that lack SCR to estimate a median cost of SCR installation (on a $/ton basis). In this case the "input" NO_X rate was, generally, the 2023 baseline NO_X rate engineering analysis rate (see Section B in the Ozone Transport Policy Analysis Proposed Rule TSD for details). For units with existing SNCR controls, for the "input" NO_X rate, we identified each unit's maximum monthly emission rate from the period 2009-2021. Costs were estimated for units that had "input" NO_X rates of at least 0.14 lb/MMBtu prior to installation of the post-combustion control. With the control installed, the output NO_X rate was reduced to a value of 0.05 lb/MMBtu. Furthermore, we assumed annual operation of the control and assumed a capacity factor of 56% (the capacity factor for coal units from the Summer 2021 IPM v.6 reference case). In this instance, these assumptions produce an emission weighted average of $11,000/ton, a median value of $13,700/ton and a 90th percentile value of $20,900/ton. EPA repeated these calculations for the subset of coal-fired units less than 100 MW and found a median value of $15,500/ton and a weighted average of $11,900/ton.[46]

In states linked in 2026, there are 21 non-CFB coal steam units at least 100 MW that are currently equipped with SNCR that reported emissions. In 2021, those units had a combined 17,000 tons of OS NO_X emissions, with a weighted average NO_X rate of 0.17 lb/MMBtu. If those were to have a achieved a 0.05 lb/MMBtu emission rate, commensurate with retrofitting a new SCR, they could reduce 12,000 tons

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emission rate for units burning bituminous coal, though units burning subbituminous and lignite coal could achieve lower emission rates. Improvement in the catalyst and additional experience constructing and operating SCRs has resulted in higher confidence in guaranteeing lower emission rates, even for units burning bituminous coal. See " Coal-Fired SCR Cost Methodology" and "Gas-Fired SCR Cost Methodology" for details..

[45] For these hypothetical cases, the "input" NO_X rate includes the effects of existing combustion controls (e.g., low NO_X burners).

[46] See the NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx for details of this calculation.

of OS NO_X emissions, with several units achieving reductions of over 1,000 tons of OS NO_X each. Because these units are already achieving some level of NO_X emission reduction with an SNCR, the dollar per ton cost would be greater for these units than comparable units that lacked SNCRs. If an existing SNCR achieves 25% removal efficiency, upgrading to an SCR with 90% removal efficiency would add an incremental 65% removal efficiency. Assuming the SCR retrofit costs about the same for a unit whether or not it already has an SNCR, then the SCR retrofit cost would properly be spread over only the incremental tons of reductions. This would lead to the per ton cost increasing by 38%, not accounting for cost savings because SCRs have a lower per ton O&M cost than SNCRs.

For a hypothetical unit 500 MW in size with a relatively low input NO_X rate (e.g., 0.17 lb NO_X/MMBtu, bituminous fuel, 2 lb SO_2/MMBtu, 70% removal efficiency, 56% capacity factor, and 10,000 Btu/kWh heat rate), the capital cost was about $155,000,000. Assuming an annual capital recovery factor of 0.143, NO_X rate of 0.17 lb/MMBtu and removal efficiency of 70% and annual operation, the cost per ton was $17,000/ton ($15,200/ton for the capital cost, $300/ton for the FOM cost, and $1,500/ton for the VOM cost).Repeating the fleet-wide analysis of SCR retrofit cost, but limited to just units with SNCR that could be considered for SCR retrofit (at least 100 MW in size and non a circulating fluidized unit), results in an emission weighted average of $13,400/ton, a median value of $14,100/ton and a 90th percentile value of $19,000/ton. These costs are not simply 38% higher than the fleet-wide analysis for all units without SCR because this subset of units has different characteristics than the wider fleet.

Oil/Gas Steam:

To understand the effect of input NO_X rate on costs, using the Retrofit Cost Analyzer equations, the EPA performed a bounding analysis to identify reasonable high and low per-ton NO_X control costs for adding SCR post-combustion controls across a range of potential input NO_X rates.[47] For a hypothetical unit 500 MW in size with an input NO_X rate of 0.14 lb NO_X/MMBtu, 79% removal efficiency, 26% capacity factor, and 10,000 Btu/kWh heat rate using natural gas, the capital cost was about $60,000,000. For a similar unit with an input NO_X rate of 0.2 lb/MMBtu and 85% NO_X removal efficiency, the total capital cost was $61,000,000. The cost on a per-ton basis varies with the assumptions concerning the operation of the unit and the book life of the loan (or lifetime of the equipment). Assuming an annual capital recovery factor of 0.143, NO_X rate of 0.14 lb/MMBtu and removal efficiency of 79% and annual operation, the cost per ton was $14,700/ton ($13,600/ton for the capital cost, $300/ton for the FOM cost, and 800/ton for the VOM cost). For the unit with the NO_X rate of 0.2 and removal efficiency of 85%, the costs were $9,900/ton ($9,000/ton for the capital cost, $200/ton for the FOM cost, and $700/ton for the VOM cost).

For this proposed rule, EPA examined the remaining oil/gas steam fleet that lack SCR to estimate a median cost of SCR installation (on a $/ton basis). In this case the "input" NO_X rate was, generally, the 2023 baseline NO_X rate engineering analysis rate (see Section B in the Ozone Transport Policy Analysis Proposed Rule TSD for details). For units with existing SNCR controls, for the "input" NO_X rate, we identified each unit's maximum monthly emission rate from the period 2009-2021. Costs were estimated for units that had input NO_X rates of at least 0.14 lb/MMBtu prior to installation of the post-combustion control and decreasing to rates of 0.03 lb/MMBtu following control installation. EPA relied on the same methodology for determining SCR optimization at these units to inform its estimate of emission rate

[47] For these hypothetical cases, the "input" NO_X rate includes the effects of existing combustion controls (e.g., low NO_X burners).

performance for SCR operation at new retrofits, which agreed with the emission rate achievable with an SCR retrofit described in “Gas-Fired SCR Cost Methodology.” Furthermore, we assumed annual operation of the control and assumed a capacity factor of 26% (the capacity factor for coal units from the Summer 2021 IPM v.6 reference case). In this instance, these assumptions produce an emission weighted average of $7,700/ton, a median value of $10,000/ton and a 90th percentile value of $15,300/ton.[48] EPA repeated these calculations for the subset of oil/gas steam units less than 150 tons per ozone season and found a weighted average of $15,600/ton.[49]

G. Generation Shifting

For this proposed rule, EPA modeled generation shifting to units with lower NO_X emission rates only within the same state as a proxy for estimating the amount of generation that could be shifted in the near-term (i.e., by 2023 and 2026). For 2023, by limiting economic builds in IPM to baseline projected levels we further assume that such generation shifting only occurs within and among all generators (including non-fossil sources) that are already in operation and connected to the grid in EPA’s IPM baseline. Under these circumstances, shifting generation to lower NO_X- or zero-emitting EGUs, similar to operating existing post-combustion controls, uses investments that have already been made, and can significantly reduce EGU NO_X emissions relatively quickly. For example, natural gas combined cycle (NGCC) facilities can achieve NO_X emission rates of 0.0095 lb/MMBtu, compared to existing coal steam facilities, which emitted at an average rate of 0.12 lb/MMBtu of NO_X across the 22 states included in the CSAPR Update in 2019. Similarly, generation could shift from coal units lacking post-combustion controls to coal units with SCR-or SNCR post-combustion controls. Shifting generation to lower NO_X-emitting EGUs would be a cost-effective, timely, and readily available approach for EGUs to reduce NO_X emissions. In 2026, IPM builds were not constrained to baseline levels, resulting in the potential for additional reductions as a result of building additional lower emitting capacity beyond the levels selected under the baseline, consistent with the assumption of new control installations in budget setting. EPA considers that the amount of generation shifting modeled to occur within each particular linked state in response to the selected control strategy represented by $1,800/ton and $10,000/ton reflects the generation shifting that can occur in the 2023 and 2026 ozone seasons, respectively.[50] Figures G.1, G.2, and G.3 below illustrate the relatively low amount of generation-shifting assumed in EPA’s analysis relative to historical levels.

[48] See the “NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx”
[49] See the “NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx”
[50] EPA conducted IPM runs to determine emission reductions associated with generation shifting at $10,000/ton, but ultimately determined that $11,000/ton should be the representative cost of retrofitting an SCR on a coal steam unit and associated NO_X mitigation strategies. Therefore, the $11,000/ton cost threshold incorporates the $10,000/ton generation shifting. To accurately describe the analysis conducted, EPA is labeling the generation shifting conducted as $10,000/ton in this section of the TSD. Since that NO_X price did not induce significant amounts of generation shifting, given the other mitigation strategies included in the model run, EPA does not believe that the results would have changed appreciably if a $11,000/ton price on NO_X was included instead.

Figure G.1. Regional Coal and Gas Summer Generation Changes Base to Cost Threshold Case (2023, GWh)

Region	Coal Adj. Base Case	Coal ($1,800/ ton)	Coal Change	Coal Percent Change	Combined Cycle Adj. Base Case	Combined Cycle ($1,800/ ton)	Combined Cycle Change	Combined Cycle Percent Change
MISO	85,803	84,784	-1,019	-1.19%	101,891	102,260	368	0.36%
NY	0	0	0	0.00%	28,807	28,790	-17	-0.06%
PJM	51,276	50,488	-788	-1.54%	157,994	158,939	945	0.60%
SERC	50,540	50,494	-46	-0.09%	132,264	133,281	1,018	0.77%
ERCOT	12,966	12,077	-889	-6.86%	92,320	93,280	961	1.04%
WECC	29,058	28,889	-169	-0.58%	88,115	88,949	834	0.95%

Figure G.2. Regional Coal and Gas Summer Generation Changes Base to Cost Threshold Case (2026, GWh)[51]

Region	Coal Adj. Base Case	Coal ($10,000/ ton)	Coal Change	Coal Percent Change	Combined Cycle Adj. Base Case	Combined Cycle ($10,000/ ton)	Combined Cycle Change	Combined Cycle Percent Change
MISO	71,889	65,975	-5,914	-8.23%	101,799	102,383	584	0.57%
NYISO	0	0	0	0.00%	27,100	27,873	773	2.85%
PJM	40,588	39,090	-1,498	-3.69%	161,380	161,880	500	0.31%
SERC	40,345	37,748	-2,596	-6.43%	133,603	136,091	2,488	1.86%
ERCOT	6,203	2,345	-3,858	-62.20%	81,016	84,724	3,707	4.58%
WECC	26,707	24,319	-2,388	-8.94%	92,567	95,151	2,584	2.79%

Figure G.3. Historical Rate of Generation Change for Coal and Combined Cycle Units

	Coal GWh 2016	Coal GWh 2017	Coal GWh 2018	Coal GWh 2019	Average annual change	Combined Cycle GWh 2016	Combined Cycle GWh 2017	Combined Cycle GWh 2018	Combined Cycle GWh 2019	Average annual change
Total linked states	450,217	425,755	400,888	328,390	-9.8%	354,841	337,916	393,282	422,744	6.4%

[51] Emission reductions derived from generation shifting will be captured in the dynamic budgets in all cases. For the pre-set budget years, and the illustrative 2026 values shown above, it is estimated and incorporated through an additional calculation step. For dynamic budget years, it will be directly incorporated through the inclusion of updated heat input data reflecting observed, post-compliance generation shifting – therefore the need for an "estimation" is mooted.

H. Feasibility Assessment: Implementation Timing for Each EGU NO_X Control Strategy

Restarting and Optimizing Existing Post-Combustion Controls

EPA evaluated the time it would take for EGUs to turn on idled SCRs and SNCRs. The EGU sector is very familiar with restarting SCR and SNCR systems. Based on past practice and taking account of the steps needed to restart the controls (e.g., re-stocking reagent, bringing the system out of protective lay-up, performing inspections), returning these idled controls to operation is possible by 2023. In states included in the NO_X Budget Trading program, 2005 EGU NO_X emission data suggest that 126 out of 156 coal-fired units with SCR operated the systems in the summer ozone season, likely for compliance with the program, while idling these controls for the remaining seven non-ozone season months of the year.[52] Similarly, in 2005, 20 of 72 coal-fired units with SNCR in the NO_X Budget Trading program operated in both the ozone season and non ozone season and had ozone season NO_X rates more than 25% below their non ozone season NOX rates suggesting that the SNCR was operated during the ozone season and may not have been operated during non ozone season.[53] To comply with the seasonal NO_X limits, these SCR and SNCR controls were regularly taken out of and then returned to service within seven months. Therefore, EPA believes this SCR and SNCR optimization mitigation strategy is available for the 2023 ozone season.

EPA also found there are very few units that appear to have fully idled their SCRs. EPA assessed the number of coal-fired units with SCR that are currently operating with ozone-season emission rates greater than or equal to 0.2 lb/MMBtu suggesting that their units may not be operating their NO_X post-combustion control equipment. EPA finds that only 8 units in the contiguous United States (of which four are in states that are "linked" at or above 1% in this proposed rule) fit this criterion.[54] EPA's assumptions that this mitigation technology is available for the 2023 ozone-season is further bolstered given that the previous rulemakings (i.e., CSAPR Update and the Revised CSAPR Update) identified turning on and optimizing existing SCR as a cost-effective control technology available by the next ozone season after those rules were promulgated. Many sources successfully implemented that strategy in response to those rules, and it appears that only a low number of units in the regions covered by these rules may have entirely ceased operating these controls subsequently. Similarly, for SNCRs (as shown above where the cost of operating an existing SNCR control is described), most units are currently operating these controls, meaning that timing considerations need to focus on additional reagent acquisition.

Full operation of existing SCRs that are already operating to some extent involves increasing reagent (i.e., ammonia or urea) flow rate, and maintaining and replacing catalyst to sustain higher NO_X removal rate operations. As with restarting idled SCR systems, EGU data demonstrate that operators have the capability to fully idle SCR systems during winter months and return these units to operation in the summer to comply with ozone season NO_X limits. The EPA believes that this widely demonstrated behavior also supports our finding that fully operating existing SCR systems currently being operated, which would necessitate fewer changes to SCR operation relative to restarting idled systems, is also

[52] Units with SCR were identified as those with 2005 ozone season average NO_X rates that were less than 0.12 / lb MMBtu and 2005 average non-ozone season NO_X emission rates that exceeded 0.2 lb/MMBtu.
[53] For this analysis, we identified units that had heat input greater than zero in both seasons and had non-ozone season NO_X rates above 0.20 lb/MMBtu.
[54] See the "2021 NO_X Rates for 234 SCR Coal Units.xlsx" file in the docket for details. Of the four units in states linked at or above 1%, three are in Missouri and one is in Pennsylvania.

feasible for the 2023 ozone season. Regarding full operation activities, existing SCRs that are only operating at partial capacity still provide functioning, maintained systems that may only require increased chemical reagent feed rate up to their design potential and catalyst maintenance for mitigating NO_X emissions. Units must have adequate inventory of chemical reagent and catalyst deliveries to sustain operations. Considering that units have procurement programs in place for operating SCR, this may only require updating the frequency of deliveries. This may be accomplished within a few weeks. The vast majority of existing units with SCRs covered in this action fall into this category. To the extent that there are any existing units with fully idled SNCR systems, the same timing considerations and conclusions apply. Moreover, since SNCR systems do not require catalyst, and may only need additional ammonia or urea reagent, the timing may even be faster than that for SCR systems. EPA concludes that these SNCR systems could be fully operational within a few weeks.

Moreover, hourly unit-level data, such as that shown in Figure B.3, clearly show that SCR performance can improve within a 2-month time frame. Specifically, when controls are partially operating (as EPA has demonstrated is the case in nearly all units with optimization potential), the data shows the hourly emission rate varying significantly (reflective of SCR performance) over hours that occur well within two months of one another. For instance, the size of the rectangle in Figure B.3 showing hourly NO_X rates for the unit when the control is partially operating in 2017 and 2018 reflect the 25th-75th percentile hours. The top left graphic shows emission rates varying between approximately 0.22 b/MMBtu to 0.07 lb/MMBtu in 2017 for instance. This variation, reflective of SCR performance, is occurring within a two-month time span, indicating the ability for quick improvements in control performance even controlling for load levels.[55]

Combustion Control Upgrades

Combustion controls, such as LNB and/or OFA, represent mature technologies requiring a short installation time – typically, four weeks to install along with a scheduled outage (with order placement, fabrication, and delivery occurring beforehand and taking a few months). Construction time for installing combustion controls was examined by the EPA during the original CSAPR development and is discussed in the TSD for that rulemaking entitled, "Installation Timing for Low NO_X Burners (LNB)", Docket ID No. EPA-HQ-OAR-2009-0491-0051.[56] Industry has demonstrated retrofitting LNB technology controls on a large unit (800 MW) in under six months (excluding permitting). This TSD is in the docket for the CSAPR Update and for this rulemaking.

Retrofitting Post-Combustion Control Technologies

SNCR is a mature, post-combustion technology that requires about 12 months from award through commissioning (not including permitting) at a single boiler. Conceptual design, permitting, financing, and bid review require additional time. A month-by-month evaluation of SNCR installation is discussed in EPA's "Engineering and Economic Factors Affecting the Installation of Control Technologies for

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55 Unit-level hourly emission rate data at www.epa.gov/ampd. See also "Miami Fort Hourly Emission Rate at Capacity Factor of 50%-80%" in the docket for this rulemaking. This file shows the emission rate changes occuring withing two months of one another.

56 http://www.epa.gov/airmarkets/airtransport/CSAPR/pdfs/TSD_Installation_timing_for_LNBs_07-6-10.pdf

Multipollutant Strategies," located in the docket for this rulemaking.[57,58] The analysis in this exhibit estimates the installation period from contract award as within a 10–13-month timeframe. The exhibit also indicates a 16-month timeframe from start to finish, inclusive of pre-contract award steps of the engineering assessment of technologies and bid request development. EPA is therefore assuming SNCRs can be retrofit in 16 months, consistent with the more complete timeframe estimated by the analysis in the exhibit.

SCR is a mature, post-combustion technology, for which EPA makes a fleetwide retrofit timing assumption of about 3 years. Unit-specific installation timing depends on site-specific engineering considerations and on the number of installations being considered. A month-by-month evaluation of SCR installation is discussed in EPA's "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies," located in the docket for this rulemaking.[59] A detailed analysis for a single SCR system and a seven-SCR system can be found in Exhibits A-3 and A-4 of the report. For a single SCR, the analysis in this exhibit estimates the installation period from contract award in a 16-month timeframe. The exhibit also indicates a 21-month timeframe from start to finish, inclusive of pre-contract award steps of the engineering assessment of technologies and bid request development, though there are instances of SCR retrofits taking as little as 9 months from contract award to completion (about 13 months allowing for work prior to contract award).[60] At a facility with multiple SCR units, the facility can stagger installation to minimize operation disruptions. For a seven-unit SCR system, the analysis in this exhibit finds that seven SCR units could be installed at a single facility in 35 months, or roughly an incremental 2.5 months per additional retrofit. EPA notes that most of the SCR retrofits that may be expected in response to this proposed rule would happen at facilities where only one or two boilers would need to be retrofit. EPA believes the timing estimates for SCR installation have not changed significantly since the publication of this report.

In addition to these prior reports and installation schedules cited above and in prior CSAPR Rules, EPA assessed the schedules again as it prepared this proposal. In the summer of 2021, a third party engineering and consulting firm provided an assessment based on the latest data of SCR cost, performance, and timing assumptions. This timing assessment is consistent with the timing schedules described in EPA's analysis. In particular, the findings noted that a SCR project could go from capital investment to commercial operation in 30-36 months, with faster schedules possible if motivated by a deadline or compliance date.[61]

The availability of skilled labor – specifically, boilermakers – is an important consideration for, and potential constraint to, the installation of a significant amount of emission controls. Significant analysis on boilermaker labor was conducted by the EPA to verify that sufficient boilermaker labor would be available to support the installation of pollution control retrofits required by Clean Air Interstate Rule

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[57] "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies" (EPA) http://nepis.epa.gov/Adobe/PDF/P1001G0O.pdf

[58] Exhibit A-5 in "Final Report: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies" shows the timeline for retrofitting an ACI system, which has an equivalent timeline to an SNCR.

[59] "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies" (EPA) http://nepis.epa.gov/Adobe/PDF/P1001G0O.pdf

[60] The AES Somerset station completed an SCR retrofit on a 675 MW boiler in 9 months from contract award. The Keystone plant retrofit SCR on two 900 MW boilers are estimated to have taken just 17 to 19 months, even allowing for a relatively long 6 to 8 months of preliminary engineering and contract negotiation. Two 600 MW units at New Madrid were retrofit with SCR, with the first unit being retrofit in about 20 months from contract award.

[61] See "Typical SCR and SNCR Schedule (Coal or Oil/Gas boilers)" in the docket for this rulemaking.

(CAIR), and can be found in the Boilermaker Labor Analysis for the Final Clean Air Interstate Rule TSD.[62] At the time of CAIR implementation, the US boilermaker population was estimated to be 28,000 boilermakers, based on International Brotherhood of Boilermakers (IBB) membership in 2003. EPA analysis showed that the boilermaker population of 28,000 provided more than enough available boilermaker labor to install the incremental 24 GW of SCR retrofits projected to be required by the rule in a three-year time period, in addition to 49 GW of scrubbers over the same time period. As of September 28, 2021, the IBB reports its active membership at 47,615 members, a 70% increase in membership over the past 18 years.[63] In analyzing the labor availability necessary for the installation of 73 GW of SCR on 142 units and 123 GW of SNCR on 497 units that was projected under the NO_X SIP Call, EPA found that approximately 13,000 to 19,000 workers would be capable of completing all SCR and SNCR installations over a two to three year period.[64] Given that there are now more boilermakers available, and EPA is projecting 32 GW (14 GW of coal steam units; 18 GW of oil/gas steam units) of incremental SCR retrofits as part of this proposed rule,[65,66] EPA believes the current number of boilermakers will provide sufficient labor availability to install all of the SCR retrofits in this proposed rule in the proposed implementation timeline.

The air pollution control industry has demonstrated that they are able to install significant amounts of air pollution control equipment in short periods of time. Based on EPA data and analysis, SCRs went online for the first time on approximately 41.7 and 15.6 GW of coal-fired capacity in 2003 and 2002, respectively, as a result of the NO_X SIP Call.[67] In addition to the large number of SCRs installed during this time, boilermakers were also working on an unusually high number of natural-gas fired power plants during the same period. In the three decades prior to 2000, an average of 5 GW of new natural gas capacity was constructed in the United States per year. However, from 2000 to 2004 there was on average 41 GW of new natural gas-fired power plant builds, for a total of 205 GW. Furthermore, the peak year for new gas power plant builds during this period, 60 GW in 2003, coincides with the peak year for SCR start-ups for the NO_X SIP call.[68] EPA believes this demonstrates a robust maximum rate of SCR start-ups after the NO_X SIP Call of 41.7 GW, which is more than enough to support the capacity of SCR retrofits in this proposed rule.

While the proposed rule does not require installation of controls on any particular source, instead leaving choice of compliance strategy to facility owners and operators, EPA projects roughly 32 GW of SCR retrofits to occur. Accordingly, EPA considers it appropriate to evaluate the feasibility of installation of the projected 32 GW of SCR retrofits on the proposed implementation timeline. EPA believes that, given the timing estimates of 21 months for a single SCR installation to 35 months for SCR retrofits on seven

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[62] "Boilermaker Labor Analysis for the Final Clean Air Interstate Rule TSD" https://archive.epa.gov/airmarkets/programs/cair/web/pdf/finaltech05.pdf

[63] "Boilermakers AFL-CIO FORM LM-2 LABOR ORGANIZATION ANNUAL REPORT 2020-2021" https://olmsapps.dol.gov/query/orgReport.do?rptId=782863&rptForm=LM2Form

[64] "Feasibility of Installing NOx Control Technologies by May 2003" https://www.regulations.gov/document/EPA-HQ-OAR-2001-0008-0125

[65] See the Regulatory Impact Analysis for this proposal

[66] EPA is also projecting 0.6 GW of SNCR being retrofit on units. As this is a very small amount and SNCR construction is much simpler than SCR, it does not affect EPA's conclusion on there being sufficient labor availability.

[67] "Boilermaker Labor Analysis for the Final Clean Air Interstate Rule TSD" https://archive.epa.gov/airmarkets/programs/cair/web/pdf/finaltech05.pdf

[68] "Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources" https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf

units at a single facility, a significant increase in boilermaker labor since 2003, and historical analysis that shows a maximum rate of SCR retrofits after the NO_X SIP Call of 41.7 GW in a single year, despite exceptionally high new gas power plant builds occurring in that same year, the SCR installation timeline in the proposed rule is feasible and consistent with past EPA analyses.

Generation Shifting

For this proposed rule, EPA examined generation shifting expected to occur when the covered fleet is subjected to a marginal cost commensurate with the identified mitigation technologies. As discussed above, this amount of generation shifting reflects the change is system dispatch as the fleet is faced a different set of economic incentives. The amount of generation shifting could occur quickly as the existing fleet readily makes unit dispatch decisions in the near term, real time based on market signals.

I. Additional Mitigation Technologies Assessed but Not Proposed in this Action

1. Combustion Control and SCR Retrofits on Combined Cycle and Combustion Turbine Units

Combined Cycle:

While many newer and/or larger combined cycle units are equipped with SCRs, some smaller, older units do not have a post-combustion control. Based on sample cost estimates, EPA's estimate of the cost of retrofitting an SCR on a 90 MW natural gas combined cycle unit (operating at an 65% capacity factor and a 0.05 lb/MMBtu NO_X emissions rate) to have an overnight project cost of $5.5 million dollars with an annual O&M cost of $265,000, or roughly $12,000/ton.[69]

Evaluating the fleet of combined cycle units in states linked in 2026, there are 45 units, or about 4 GW of capacity, that do not have an SCR, had a NO_X emissions rate over 0.05 lb/MMBtu, and a capacity factor above 10%. If those units were retrofit with SCR, they would have a reduction potential 3,100 tons, or about 70 tons per unit.

Combustion Turbine:

Roughly 75% of Combustion Turbines use either water injection, Dry Low NO_X Burners (DLN), or Ultra Low NO_X Burners (ULN). In some circumstances, these technologies can be difficult to retrofit, given requirements for either access to sufficient water or space for upgraded combustors. It is estimated that retrofitting DLN or ULD on a 50 MW combustion turbine that only operated in the summer at a 15% capacity factor and NO_X emission rate of 0.15 lb/MMBtu would have a project cost of roughly $2.2 million dollars with an annual O&M cost of $53,000. That translates to a cost of roughly $21,600/ton.[70]

Evaluating the fleet of combustion turbine units in states linked in 2023, there are 11 units, or about 780 MW of capacity, that: do not have combustion controls and could achieve a lower emission rate by retrofitting them; and operated at a capacity factor greater than 10% on average for the 2019-2021 ozone

[69] See the NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx and the report "Combustion Turbine NOx Technology Memo."
[70] See the NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx and the report "Combustion Turbine NOx Technology Memo."

seasons. Those units have combined 2021 ozone season NOX emissions of 286 tons. If those units were to retrofit with DLN/ULN, they would have a reduction potential of 143 tons, or about 13 tons per unit.[71]

While almost 20% of the combustion turbine fleet has an SCR, many units do not have SCRs and operate at relatively low capacity factors and/or emission rates. EPA estimates the cost of retrofitting an SCR on a 50 MW combustion turbine unit (operating at a 15% capacity factor during the ozone season, and negligibly the rest of the year, and a 0.15 lb/MMBtu NO_X emissions rate) to have an overnight project cost of $14 million dollars with an annual O&M cost of $62,000. The relatively low utilization of the unit and high project cost imply a cost of roughly $102,000/ton.[72]

2. Mitigation Strategies at Small Units that Operate on High Electricity Demand Days (HEDD)

Within the universe of combustion turbine EGUs, EPA also examined the subset of units that typically operate in a "peaking" fashion (i.e., those with low seasonal capacity factors and operating primarily on days of peak electricity demand). EPA did not identify a broadly available mitigation strategy across this class of units that was within the range of cost effectiveness values of other EGU strategies included in the proposal at step 3, or that had relatively favorable air quality benefit to cost ratios (as discussed in preamble section VI.D). 890 out of 1117 combustion turbines included in EPA's 2023 analysis for linked states operated at a capacity factor of 15% or less across the 2021 ozone season (i.e., at levels suggesting a peaking unit) and averaged less than 0.1 ton of NO_X per day. The vast majority emitted less than 5 tons for the season and did not have a day where they exceeded a single ton of emissions. This heavy weighting towards low overall emissions and low emission-reduction opportunities from this subset of units suggests a uniform mitigation strategy applied to all units would deliver relatively little reductions relative to the amount of sources and relative to the average cost. However, EPA recognizes that within the heterogenous universe of combustion turbine EGUs, there may be instances where mitigation measures are cost effective for a given unit. In addition, these units generally operate as part of the interconnected electricity grid with other EGUs. Therefore, EPA includes this class of units in its CSAPR trading programs and proposes the same approach in this proposed rule. This creates an economic incentive for emissions reductions to be realized from this class of units to the extent such opportunities exist.

Types of mitigation strategies that could be installed on peaking units range from combustion controls such as water injection technology to post-combustion controls such as SCR retrofit. As discussed in I.1, using representative values characteristic of uniform control treatment, these costs could range from $24,000/ton (combustion controls) to $115,000/ton (post-combustion control) on average when applied to the combustion turbine fleet. A mitigation strategy of broadly assumed generation shifting away from these sources is both limited by the fact that 1) many of these units operate at peak demand times and may

[71] Using a tons per season rather than a capacity factor cutoff, the fleet of combustion turbine units in states linked in 2023, there are 32 units, that: do not have combustion controls and could achieve a lower emission rate by retrofitting them; and emitted 10 or more tons on average for the 2019-2021 ozone seasons. Those units have combined 2021 ozone season NO_X emissions of 995 tons.
[72] See the NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx and the report "Combustion Turbine NOx Technology Memo."

serve critical reliability purposes, and 2) the overall reduction potential is limited in non-peak times as these units generally do not operate during those periods.

However, EPA's regulatory coverage and allowance holding requirements for these units will extract emission reduction across this generator type at the limited units where it may be cost effective, even when a mitigation strategy is not cost-effective across the fleet segment more broadly. The opportunity cost of an allowance surrendered to cover emissions is anticipated to incentivize any mitigation behavior where viable in this universe of units and cost-effective at the level of stringency of the overall EGU control strategy (i.e., around $11,000/ton).

EPA also identifies two features of these units that make this segment well suited towards a market incentive approach as opposed to assuming any uniform at-the-source mitigation strategies or unit-specific rate limitations. These are: 1) reliability considerations and 2) existing and ongoing state regulatory developments.

Peaking units play a unique role in ensuring grid reliability, and in certain areas, as a result of their function, also may contribute relatively large emissions to ozone levels at nearby receptors. The days that are conducive to ozone in the summer tend to have high temperatures, and as a result, are associated with substantial additional electricity demand from air conditioning (among other reasons). To meet this incremental demand, particularly in some areas where there are noted transmission constraints, small units that have relatively high emission rates initiate operation. These units are often simple cycle combustion turbines or oil-fired boilers. They are usually small and only operate a few hours out of the summer when they are critical to meeting demand. The generation they provide is likely critical to ensuring grid stability and power system reliability during these high-demand times.

EPA recently evaluated unit-level operations on HEDD for the States in the Revised CSAPR Update. In the 12 states affected by the CSAPR Update Revision, EPA identified a total of 1,096 units that operated during the 2019 ozone season. Of these, 102 units exhibited capacity factors that fell below 10% for the period. The majority of these units (94 out of 102) were combustion turbine units—29 of which were fueled by oil and 65 were fueled by natural gas. While the 102 identified units, called "peaker units" here (in reference to their use during "peak" electricity demand), operated in relatively few hours during the 2019 ozone season, an average of 13% of gross generation from these units occurred in higher energy demand hours, which we define as the top 1% of hours with the highest regional electric load. For 18 of these units, electricity production in higher energy demand hours accounted for at least 20% of their total generation for the 2019 ozone season.

With their relatively high emission rates, relatively small seasonal capacity factors, and tendency to operate on HEDD, the emissions from these units could have substantial emissions and air quality impacts on high ozone days. An assessment of emissions intensities for the units relative to the state and regional average emission rate indicates that the emission rates of these units can be up to 118 times their respective state averages. In the 12-state region, 50 units across 17 facilities had emission intensity values substantially higher than the state average. Dividing the unit-level 2019 ozone season NO_X rate by the average 2019 ozone season NO_X rate for the state indicated that the emission rates for these units were at least 20 times that of their respective state averages for the 2019 ozone season.

In a separate analysis, EPA identified six states located in the northeastern US in which significant air quality problems may persist on HEDD—Pennsylvania, New Jersey, New York, Delaware, Connecticut, and Maryland. For a better understanding of the emissions impact of combustion turbine unit operations, we compared the peak hour generation and emissions activities of natural gas and oil units located in these states on sample HEDD and low energy demand days (LEDD). The sample days were chosen from a selection of 15 days in the 2019 ozone season with the highest and lowest cumulative daily gross load for all EGUs in CAMD's data sets in the six states. The sampled HEDD and LEDD days and peak hours used in the analysis are July 30, 16:00, and May 18, 18:00, respectively.

When comparing gross generation between the two days, we observe that combustion turbine natural gas and oil units generate more in days and hours of higher energy demand. On the sampled LEDD, combustion turbine natural gas and oil units in the six northeastern states provided a total of 3,953 MWh of electricity over the course of the day—673 MWh of which was produced in the peak hour (Figure I.1), contributing to 539 lbs, or 9% of the total peak hour NO_X emissions in the six states (Figure I.2). Comparatively, on the HEDD, gross generation from combustion turbine units amounted to 28,263 MWh over the course of the day. Generation in the peak hour reached 2,207 MWh (Figure I.1), and contributed to 4,881 lbs, or 19% of total peak hour NO_X emissions (Figure I.3).

For the sampled HEDD day, the largest shares of peak hour NO_X emissions from combustion turbine units originate in New York and Pennsylvania (Figure I.3). A unit-level assessment of peakers in New York state indicates that while these units are highly emissions-intensive, they provide relatively minimal generation in peak hours. Specifically, combustion cycle natural gas and oil units in New York contribute to 1,359 lbs, or 19%, of the state's total peak hour NO_X emissions on the sample HEDD, while only providing 1,186 MWh, or 8%, of generation. On this sample HEDD, the Glenwood and Holtsville facilities, in particular, account for 4% of total peak hour oil generation in New York but contribute to 31% of the total peak hour NO_X emissions from oil units (Figure I.4). With peak hour NO_X rates of 0.44 lb/MMBtu and 0.58 lb/MMBtu, respectively, the Glenwood and Holtsville facilities are relatively emissions intensive; however, these units only dispatch in hours and days with higher energy demand. In 2019, Glenwood operated a total of 31 hours, 19 of which fell in the ozone season, while Holtsville ran a total of 403 hours. Of these, 222 hours fell in the ozone season.

These units have the highest emissions, and the most downwind impact, on particular HEDDs and at particular receptors that are in relatively close proximity to the peaking units. As discussed above, they otherwise do not have emissions levels, impacts, or cost-effective emission reduction opportunities that would warrant imposition of additional control requirements (other than inclusion in the trading program) at step 3 under the good neighbor provision for the 2015 ozone NAAQS. Moreover, in states with relatively higher concentrations of peaker units that are in closer proximity to out of state receptors identified in this proposed rule, EPA observes that mitigation measures have often been implemented. These states, New York and New Jersey, have already adopted regulations to reduce summertime NO_X emissions from peaking units, and in doing so have conducted thorough assessments of the degree of emissions reduction that is achievable from these units, particularly in light of their critical function in ensuring grid reliability.

The New York Department of Environmental Conservation (NY-DEC), for example, adopted a rule in January 2020 to limit emissions from combustion turbines that operate as peaking units. This rule, Subpart 227-3,[73] entitled "Ozone Season NO_X Emission Limits for Simple Cycle and Regenerative Combustion Turbines," applies to simple cycle combustion turbines (SCCTs) with a nameplate capacity of 15 MW or greater that supply electricity to the grid. The regulation, more commonly referred to as the "Peaker Rule", contains two compliance dates with increasingly stringent NO_X limits, as follows: by May

[73] Subpart 227-3 is found within Chapter III, Air Resources, Part 227, of Title 6 of New York Codes, Rules and Regulations (NYCRR).

1, 2023, all SCCTs subject to the rule must meet a NO_X emission limit of 100 ppmvd,[74] and by May 1, 2025, gas-fired SCCTs must meet a NO_X emission limit of 25 ppmvd, and distillate or other liquid-fueled units must a limit of 42 ppmvd. In lieu of meeting these limits directly, New York's rule offers two alternative compliance options. The first compliance option allows owners and operators to elect an operating permit condition that would prohibit the source from operating during the ozone season. The second option allows owners and operators to adhere to an output-based NO_X daily emission rate that includes electric storage and renewable energy under common control with the SCCTs with which they would be allowed to average.

New York performed comprehensive studies to assess the reliability implications of removing these units from the system. The 2020 Reliability Needs Assessment Report, carried out by the NYISO in November 2020, found that the deactivation of all peaking units impacted by New York's Peaker Rule without replacement solutions results in transmission and resource adequacy deficiencies that leave the bulk power system unable to serve the forecasted load in New York City throughout the study period (up to 2030).[75] While units can be retrofitted with new NO_X controls to comply with the rule, many of the older units in New York are not configured in a manner conducive to the retrofit pollution control technology. These units are therefore likely to elect to retire rather than pay the high installation costs for new water injection systems. Units that elect to retire are required to submit a Generator Deactivation Notice to the NYISO. If they do so, the NYISO will perform a Generator Deactivation Assessment to ensure that the retirement of the respective unit does not create reliability issues for the system. Units identified by this assessment as being necessary for grid reliability receive a two-year extension on their compliance deadlines.

New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days (HEDD), and sets operational restrictions for HEDD units that operate on these days.[76,77] New Jersey's HEDD Rules came into effect on May 19, 2009, and imposed emissions control requirements for units with NO_X rates exceeding 0.15 lb/MMBtu and lacking identified control technologies.[78]

Due to their relatively small size, large number of units, potentially high control costs, low emission reduction potential, reliability considerations, and existing regulations, EPA does not identify any uniform, cost-effective mitigation strategy for this class of units as a whole in its EGU NO_X mitigation strategy assessment for this proposal. EPA recognizes heterogeneity in receptor impacts and emissions reduction potential across these types of units, but in the one region where emissions reductions at such units may be warranted due to uniquely large impacts at nearby out-of-state receptors (i.e., in the New York City area), the immediate two upwind states have already adopted measures to reduce emissions from these units. EPA does not have sufficient information on the current record that would warrant assuming application of additional mitigation technologies beyond those already in place or otherwise incentivized or required. Nonetheless, EPA does include these units, along with all other EGUs meeting

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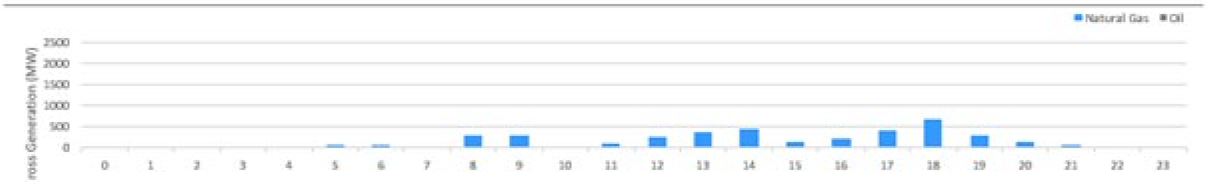
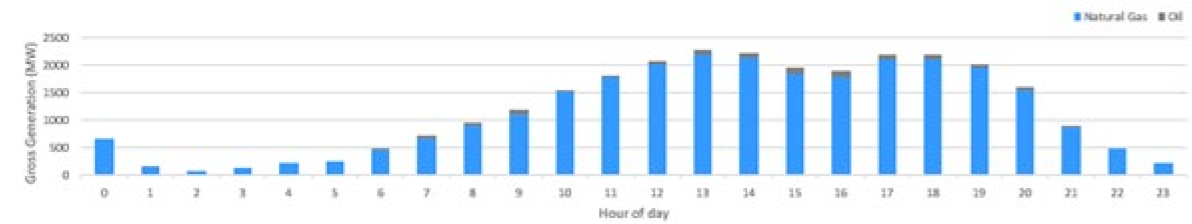
[74] Parts per million on a dry volume basis at 15% oxygen. Using a heat rate of 15,000 BTUs/KWh identified in New York's background materials for the rule and the alternative 3 lbs NO_X/MWh limit equating to 100 ppmvd, the equivalent emission rate would be approximately 0.2 lb/MMBtu and significantly lower for the full implementation of 25 ppmvd. See https://www.dec.ny.gov/docs/air_pdf/siprevision2273.pdf
[75] https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf
[76] N.J.A.C. § 7:27–19
[77] HEDD units are EGUs greater or equal to 15MW that commenced operation prior to May 1, 2005, and that operated less than or equal to an average of 50% of the time during the ozone seasons of 2005 and 2007.
[78] CTs are required to have water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or noncatalytic reduction (SNCR)

applicability criteria, in this proposed rule as covered sources (as in prior CSAPR trading programs). Inclusion in the trading program will create an economic incentive for these units to take advantage of economical emission reduction opportunities wherever available.

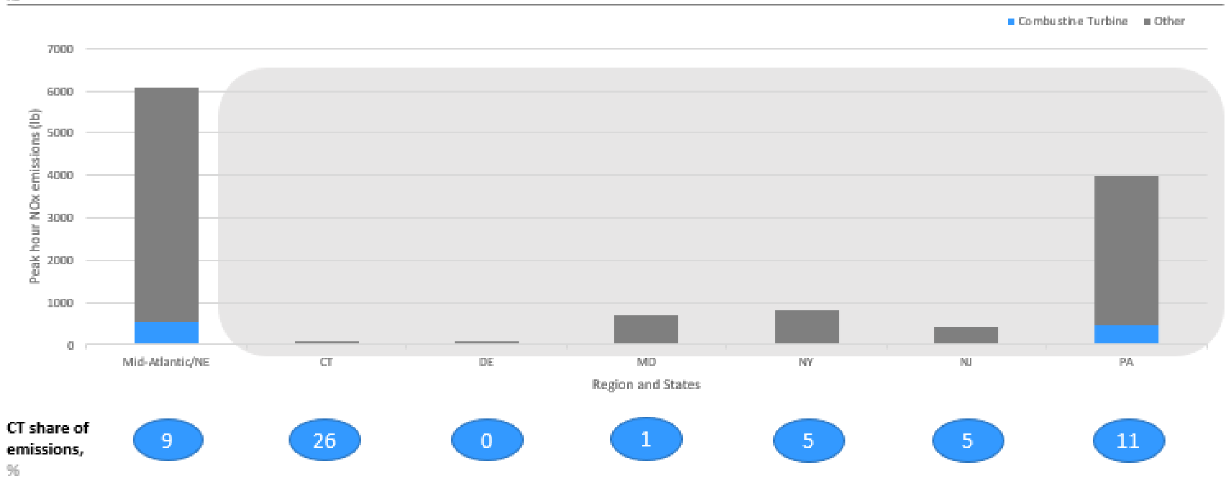
Hourly gross generation by combustion turbine natural gas and oil units in six northeastern states on LEDD,
MW



Hourly gross generation by combustion turbine natural gas and oil units in six northeastern states on HEDD,
MW



Peak hour NOx emissions by unit-type across states and region on LEDD[1],
lb



1) May 18th (18:00) is used as the exemplary LEDD day and peak hour.

Figure I.3. Percentage share of peak hour NO_X emissions by unit type across region and states on an sampled HEDD (Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2020)

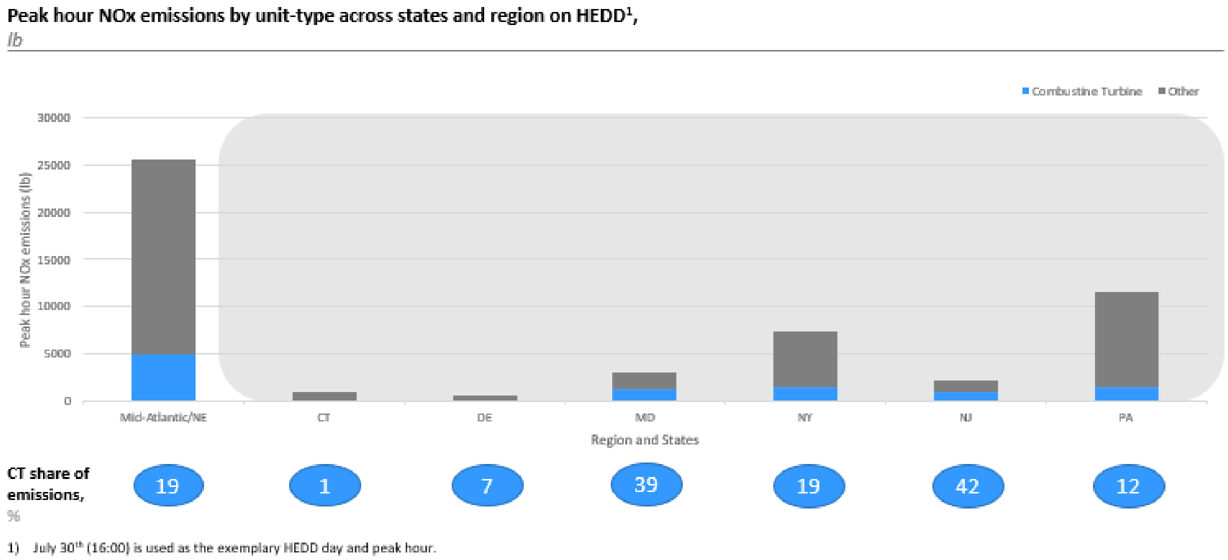
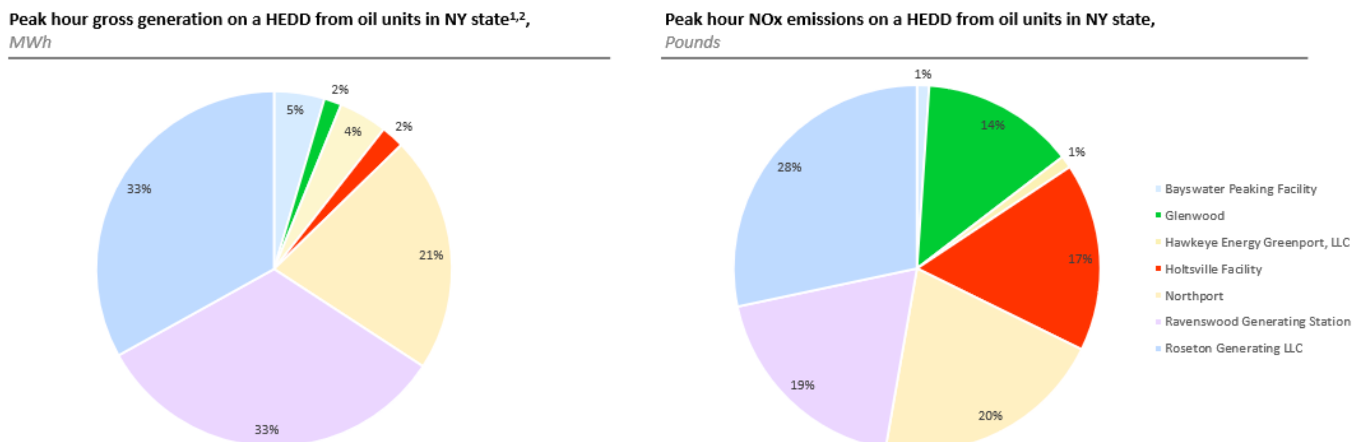


Figure I.4. Peak hour generation and emissions on HEDD by oil units in NY as a percentage (Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2020)



Appendix A: Historical Anhydrous Ammonia and Urea Costs and their Associated Cost per NO_X ton Removed in a SCR

Minimum Cost to Operate Anhydrous NH_3 & Urea costs ($/ton) [from USDA]

Year	NH_3 (anh) Cost	NH_3 Cost / ton NO_X	Urea cost	Urea Cost / ton NO_X
2009	$ 562	$ 320	$ 425	$ 425
2010	$ 548	$ 312	$ 424	$ 424
2011	$ 801	$ 457	$ 543	$ 543
2012	$ 808	$ 461	$ 746	$ 746
2013	$ 866	$ 494	$ 508	$ 508
2014	$ 739	$ 421	$ 533	$ 533
2015	$ 729	$ 416	$ 472	$ 472
2016	$ 588	$ 335	$ 354	$ 354
2017	$ 501	$ 286	$ 328	$ 328
2018	$ 517	$ 295	$ 357	$ 357
2019	$ 612	$ 349	$ 433	$ 433
2020	$ 499	$ 284	$ 375	$ 375
2021	$727	$414	$543	$543

Average price from the first reporting period in July of each year.
Source: Illinois Production Cost Report (GX_GR210) USDA-IIL, Dept of Ag Market News Service, Springfield, IL
www.ams.usda.gov/mnreports/gx_gr210.txt
www.ams.usda.gov/LPSMarketNewsPage