Technical Support Document (TSD)

for the Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS

Docket ID No. EPA-HQ-OAR-2015-0500

EGU NO_X Mitigation Strategies Final Rule TSD

U.S. Environmental Protection Agency

Office of Air and Radiation

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Introduction:

The analysis presented in this document supports the EPA's Final Cross-State Air Pollution Rule Update for the 2008 Ozone National Ambient Air Quality Standards (CSAPR Update). In developing the CSAPR Update, 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 four topics: (1) the appropriate representative cost resulting from "widespread" implementation of a particular NO_X emission control technology; (2) the NO_X emission rates commonly 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 with the Integrated Planning Model (IPM) v 5.15 and compliance feasibility for the CSAPR Update.

NO_X control strategies that are widely in use by EGUs include:

- Returning to full operation existing SCRs that have operated at fractional design capability;
- Restarting inactive SCRs and returning them to full operation;
- Restarting inactive SNCRs;
- Replacing outdated combustion controls with newer advanced technology (e.g., state-of-the-art low NO_X burners);
- Installing new SCR systems;
- Installing new SNCR systems; and
- Shifting generations (i.e., changing dispatch) from high- to low-emitting or zero-emitting units.

To evaluate the cost for 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 researched by Sargent & Lundy, a nationally recognized architect/engineering firm (A/E firm) familiar with the EGU sector.[1] EPA also used the Integrated Planning Model (IPM) to analyze power sector response while accounting for electricity market dynamics such as generation shifting.

Cost Estimate for Fully Operating Existing SCR that Already Operate to Some Extent

EPA sought to examine costs for full operation of SCR. SCR are post-combustion controls that reduce NO_x emissions by reacting the NO_X with either ammonia or urea. The SCR technology utilizes a catalyst and produces high conversion of NO_X. Fully operating an SCR includes maintenance costs, labor, auxiliary power, catalyst (if utilized), and reagent cost. The chemical reagent (typically ammonia or urea) is a significant portion of the operating cost of these controls.

EPA received comment on the costs to fully operate a SCR that was already being operated to some extent. At proposal, EPA stated that the cost could be apportioned to adding additional reagent at a cost of about \$500/ton of NO_X removed. Commenters recommended that EPA include additional variable costs to the proposed cost of \$500 per ton, including the costs of catalyst in addition to the cost of reagent. In response, EPA examined three of the variable operations and maintenance (VOM) costs: reagent, catalyst, and auxiliary power. Depending on circumstances, SCR operators may operate the system while

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[1] See: Attachment 5-3: SCR Cost Methodology (PDF) and Attachment 5-4: SNCR Cost Methodology (PDF) available at https://www.epa.gov/airmarkets/documentation-base-case-v513-emission-control-technologies

achieving less than “full” removal efficiency by using less reagent (as EPA stated at proposal), and/or not replacing degraded catalyst which allows the SCR to perform at lower reduction capabilities. Consequently, the EPA finds it reasonable to consider the costs of both additional reagent and catalyst maintenance and replacement in representing the cost of optimizing existing and operating SCR systems.

In contrast, EPA finds that units running their SCR systems have incurred the complete set of fixed operating and maintenance (FOM) costs. In addition, EPA finds that the auxiliary power component of VOM is also largely indifferent to the NO_X removal. That is, auxiliary power is indifferent to reagent consumption, catalyst degradation, or NO_X removal rate. Thus, the FOM and auxiliary power VOM cost components are not included in the cost estimate to achieve “full” operation for units that are already operating.

In conclusion, EPA finds that only the VOM reagent and catalyst replacement costs should be included in cost estimates to ensure an operating SCR operates fully.

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 CAIR and the original CSAPR, the agency identified a marginal cost of \$500 per ton of NO_X removed (1999\$) with reagent costing \$190 per ton of ammonia, which equated to \$108 per 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. To understand the relationship between reagent price and its associated cost regarding NO_X reduction, see Appendix A: Table 1; “Historical Anhydrous Ammonia and Urea Costs and their Associated Cost per NO_X ton Removed in a SCR.” Commenters suggested that in the future, prices could increase as demand increases for these commodities. However, these commodities are created in large quantities for use in the agriculture sector. Demand from the power sector for use in 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, Table 1. Some of these prices reflect conditions where demand and commodity prices are high. Consequently, the reagent costs used by EPA in this rule 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. EPA conservatively assumed a cost of \$310/ton for a 50% weight solution of urea. This results in a cost of between \$400 and \$500/ton of NO_X removed for the reagent cost alone.

As suggested by commenters, 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 Sargent & Lundy cost equations for all coal-fired units that operated in 2015 in the United States on a per ton of NO_X removed basis. This assessment covered up to 255 units. EPA was able to identify the costs of individual VOM and FOM cost components, including reagent, catalyst, auxiliary fans. Some of these expenses, as modeled by the Sargent & Lundy cost tool, 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 conservatively modeled costs with urea, the higher-cost reagent for NO_X mitigation. The key input parameters in the cost equations are the size of the unit, the uncontrolled, or “input”, NOx rate, the NOx removal efficiency, the type of coal, and the capacity factor. For the input NO_X rate, each unit’s maximum monthly emission rate was examined from the period 2002-2014 (inclusively) for the purpose of identifying the unit’s maximum emission rate prior to the control’s installation or alternatively during time periods when the control was not operating. The long timeframe allowed examination prior to the onset of annual NO_X trading programs (e.g., CAIR and CSAPR).

In the analysis, we assumed these units burned bituminous coal at a 54.1% capacity factor.[2] We assumed that the SCRs operate with an 87.55% NO_x removal efficiency.[3] In this section, where we are assessing the cost to return a partially operating SCR to full operation, we examined only the sum of the VOM reagent and catalyst cost components. EPA ranked the quantified VOM costs for each unit and identified the cost at the 90th percentile level rank, which rounded to \$800 per ton of NO_x removed. EPA also identified the average cost, which rounded to \$670 per ton of NO_x removed. EPA selected the 90th percentile value because a substantial portion of units had combined reagent and catalyst costs at or less than this \$800/ton of NO_x removed.

Thus, \$800 per ton NO_x removed represents a reasonable estimate of the cost for operating these post combustion controls based on current market prices and typical operation. For purposes of the IPM modeling, the agency assumes that \$800 per 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.

Cost Estimates for Restarting Idled Existing SCR

For a unit with an idled, bypassed, or mothballed SCR, all FOM and VOM costs such as auxiliary fan power, catalyst costs, and additional administrative costs (labor) are realized upon resuming operation through full potential capability. To understand the costs, the agency applied the Sargent & Lundy cost equations for two "typical" units with varying input NO_X rates in a bounding analysis and then did a more detailed analysis encompassing all coal-fired units with SCR that operated in 2015 in the contiguous United States. For both analyses, the agency assumed the same input parameters as was used for the partially-operating SCR analysis described above, but in keeping with this assessment's focus on restarting SCRs that are not already operating, these analyses included the auxiliary fan power VOM component and all of the FOM components along with the reagent and catalyst VOM components in the total cost estimate.

First, to better-understand the effect of input NO_X rate on costs, using the Sargent & Lundy cost equations, the EPA performed a bounding analysis to identify reasonable high and low per-ton NO_X control costs from reactivating an existing but idled SCR across a range of potential uncontrolled NO_X rates.[4] Similar to what was described at proposal, for a hypothetical unit with a high uncontrolled NO_X rate (e.g., 0.7 lb NO_X/mmBtu, 80 percent removal efficiency, 54.1% capacity factor, and 10,000 Btu/kWh heat rate), VOM and FOM costs were around \$750/ton of NO_X removed. Conversely, a unit with a low

[2] Commenters suggested that EPA evaluate costs of SCR operation utilizing a capacity factor value representing recent unit operation. EPA identified the 2015 heat input weighted ozone season capacity factor of 54.1 percent for 213 coal units with SCR on-line at the start of 2015 and which have nonzero 2015 heat input and are in the CSAPR Update region.

[3] A NO_X removal efficiency of 87.6 percent is based on the median ratio of the month with the highest NO_X rate to the second best ozone season value for the time-period 2003-2014. The agency selected the median value to ensure exclusion of outliers. Commenters questioned the particular values EPA selected for this analysis. The highest month was selected as the "uncontrolled" NO_X rate because it had a good possibility of being a time when the SCR was not operating. As averaging time increases, there is increased likelihood that the unit would be using its SCR, resulting in an "uncontrolled" NO_X rate that includes some control. The second-lowest ozone season rate was selected as the "controlled" rate. This was selected because it represented a time when the unit was consistently and efficiently operating its SCR. This is consistent with the proposal.

[4] For these hypothetical cases, the "uncontrolled" NO_X rate includes the effects of existing combustion controls present (i.e., low NO_x burners).

uncontrolled NO_X rate (e.g., 0.2 lb NO_X/mmBtu and 60 percent removal) experienced a higher cost range revealing VOM and FOM costs about $1,800/ton of NO_X removed.

Next, using the Sargent & Lundy cost equations and same input parameters described above, EPA evaluated all of the VOM and FOM costs for the 255 coal-fired units with SCR in the contiguous United States that were operating in 2015. As before, EPA ranked the sum of the VOM and FOM costs for each unit and identified the 90th percentile cost. When rounded, this was $1,400/ton of NO_X removed. EPA also identified the average cost, which rounded to $1,000 per ton of NOx removed. Specifically, this assessment found that 229 of the 255 units demonstrated VOM plus FOM costs lower than $1,400/ton of NO_X removed.[5]

Examining the results, the EPA concludes that a cost of $1,400/ton of NO_X removed is reasonably representative of the cost to resume and fully operate idled SCRs.

NO_X Emission Rate Estimates for Full SCR Operation

Similar to what was done at proposal, the agency examined the ozone season average NO_X rates for 271 coal-fired units in the contiguous US with an installed SCR over the time-period 2009-2015, then identified each unit's lowest, second lowest, and third-lowest ozone season average NO_X rate. Commenters suggested that EPA examine ozone season average NO_x rates over a shorter time period than proposed (specifically not predating 2009) since annual NO_x programs, rather than just seasonal programs, became widespread in the eastern US with the start of CAIR in 2009, and this regulatory development could affect SCR operation. While the proposal focused on second-lowest ozone season NO_X rates, commenters expressed concern that such rates may not be achievable on a routine basis.[6] Certain commenters also suggested that units were not operating at capacity factors conducive to efficient SCR operation and that units were facing additional constraints on NO_X removal by using the SCR to comply with other regulations (i.e., MATS). For responses to these comments, see the general Response to Comments document. Following comments, EPA focused on the third lowest ozone season rate over the 2009-2015 time period to ensure that the rate represents efficient but routine SCR operation (i.e., the performance of the SCR is not simply the result of being new, or having a highly aggressive catalyst replacement schedule, but is the result of being well-maintained and well-run). EPA found that, between 2009 and 2015, EGUs on average achieved a rate of 0.10 lbs NO_X/mmBtu for the third-lowest ozone season rate. The EPA selected 0.10 lbs NO_X/mmBtu as a reasonable representation for full operational capability of an SCR. EPA notes that over half of the EGUs achieved a rate of 0.076 lbs NO_X/mmBtu over their third-best entire ozone season (see Figure 1).

For the next step, the agency examined each ozone season over the time period from 2009-2015 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 0.085 lbs NO_X/mmBtu. The third-lowest historical monthly NO_x rate analysis showed that a large proportion of units displayed NO_x rates below 0.10 lb/mmBtu (see Figure 2).

[5] Given the sensitivity of the cost to the input uncontrolled NOx rates, EPA examined the units with higher costs and observed that some exhibited low, uncontrolled NO_X rates suggesting that, perhaps, the SCR may have been consistently operated year-round over the entire time-period. A low uncontrolled NO_X rate would result in a low number of tons of NOx removed, and, thus, a high cost on a "per ton of NO_X removed" basis when modest fixed and variable costs are divided by just a few tons of NO_X removed.

[6] Other commenters noted that a large group of EGUs with SCRs routinely achieved rates well below 0.075 lbs NO_x/mmBtu. EPA agrees that a large number of units can achieve these low rates. In the setting of the state budgets, EPA notes that units were given the lower of their actual rate from NEEDS or 0.10 lbs/mmBtu.

Based on the ozone season emission rates, and supported by the monthly rates, the agency concludes a 0.10 lb NO_X/mmBtu average rate is widely achievable by the EGU fleet.

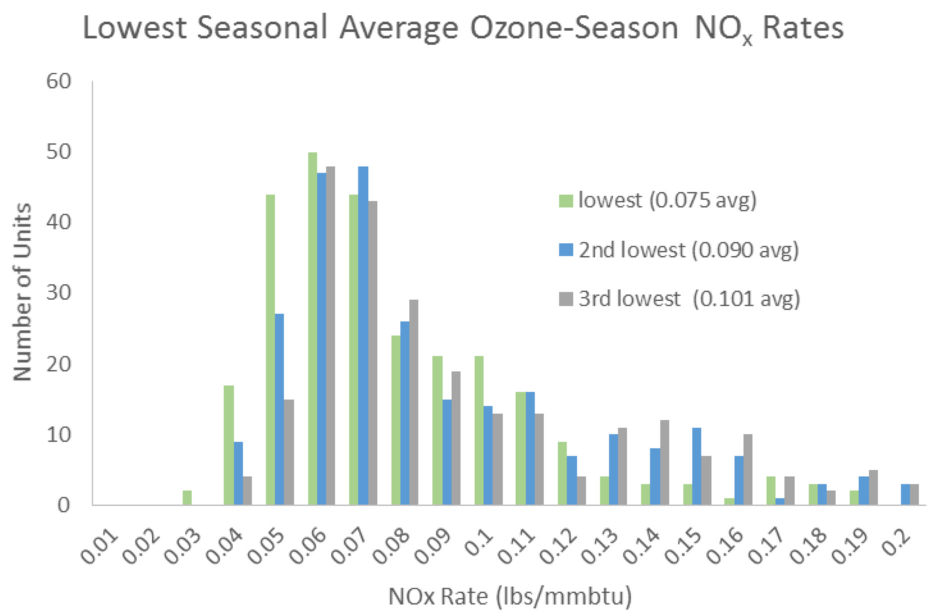

Figure 1. "Frequency" distribution plots for coal-fired units with an SCR showing their NO_X emission rates (lbs/mmBtu) during ozone seasons from 2009-2015. For each unit, the lowest, second lowest, and third lowest ozone season average NO_X rates are illustrated.

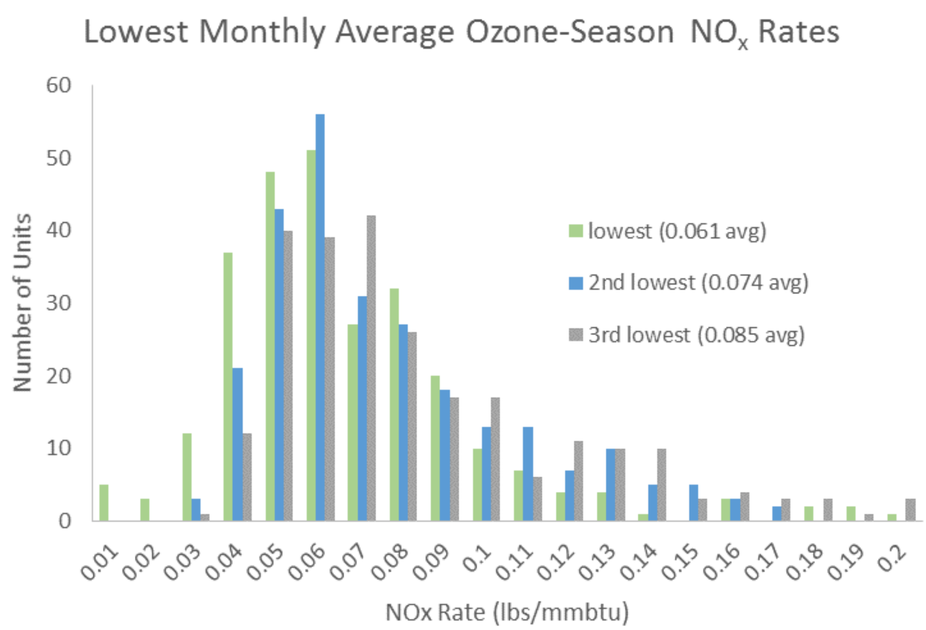

Figure 2. "Frequency" distribution plots for coal-fired units with an SCR showing their NO_X emission rates (lbs/mmBtu) during ozone seasons from 2009-2015. For each unit, the lowest, second lowest, and third lowest monthly average NO_X rates are illustrated.

Cost Estimates for Restarting Idled Existing SNCR

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 the amount of reagent must be injected to achieve a level of NOx removal comparable to SCR technology. Usually, an SNCR system does not achieve the level of emission reductions which an SCR can achieve. For the SNCR analysis, as with the SCR analyses described above, the agency used the Sargent & Lundy cost equations to perform a bounding analysis for examining operating expenses associated with a "generic" unit returning an SNCR to full operation.[1] For units with a mothballed SNCR returning to full operation, the owner incurs the full suite of VOM and FOM costs. Reagent consumption represents the largest portion of the VOM cost component. For this bounding analysis, the agency examined two cases: first, a unit with a high input uncontrolled NO_x rate 0.70 lb/mmBtu; second, a unit with a low input uncontrolled NO_x rate 0.20 lb /mmBtu – both assuming a 25 percent removal efficiency.[7] For the high rate unit case, VOM and FOM costs were calculated as approximately $1,970/ton NO_x with about $1,620/ton of that cost associated with urea procurement. For the low rate unit case, VOM and FOM costs approached $3,420/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).[1] EPA also examined SNCR cost sensitivity by varying NO_X removal efficiency while maintaining the uncontrolled NO_X emission rate. In these studies, SNCR NO_X removal efficiency was assumed to be 40 percent for the first cost estimate and 10 percent for the second cost estimate. For a high rate unit with an uncontrolled rate of 0.70 lb NO_X/mmBtu, the associated costs were $1,920/ton and $2,110/ton. For a low rate unit with an uncontrolled rate of 0.20 lb NO_X/mmBtu, the associated costs were $3,310/ton and $3,900/ton. This analysis illustrates that SNCR costs ($/ton) are more sensitive to a unit's uncontrolled input NO_X rate than the potential NO_X removal efficiency of the SNCR itself. Examining the results across all of the simulations, but focusing on the 25 percent removal efficiency scenario for the low input uncontrolled NO_X rate, which is more representative of typical removal efficiency, EPA finds that costs for fully operating idled SNCR are substantially higher than for SCR. We conclude that a cost of $3,400/ton of NO_X removed is representative of the cost to resume and fully operate idled SNCRs.

Cost Estimates for Installing Low NOx Burners and / or Over Fire Air

Combustion control technology has existed for many decades. Its emission control premise depends on limiting 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

[7] For both cases, we examined a 500 MW unit with a heat rate of 10,000 Btu/kWh operated at a 42 percent annual capacity factor while burning bituminous coal. The 2015 heat input weighted ozone season capacity factor for 105 coal units with SNCR on-line at the start of 2015 and which have nonzero 2015 heat input and are in the CSAPR Update region was 42 percent. Furthermore, in the cost assessment performed here, the agency conservatively assumes SNCR NO_X removal efficiency to be 25 percent, noting that multiple installations have achieved better results in practice. 25% removal efficiency is the default NO_X removal efficiency value from the IPM documentation. See https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-4_sncr_cost_methodology.pdf for details.

0.20 – 0.25 lb NO_X/mmBtu and, for some units, depending on unit type and fuel combusted can achieve rates well below 0.18 lb NO_X/mmBtu. Table 1 shows average NO_X rates from units with various combustion controls for different time periods.

Table 1: Ozone Season NO_X Rate (lb/mmbtu) Over Time for Units with Various Combustion Controls*

	Years Between 2003 and 2008		Years Between 2009 and 2014		Year = 2015	
NOx Control Technology	**NOx Rate (lb/mmBtu)**	**Number of Unit-Years**	**NOx Rate (lb/mmBtu)**	**Number of Unit-Years**	**NOx Rate (lb/mmBtu)**	**Number of Unit-Years**
Overfire Air	0.346	987	0.275	828	0.222	114
Low NOx Burner Technology (Dry Bottom only)	0.339	1654	0.276	1421	0.229	193
Low NOx Burner Technology w/ Overfire Air	0.299	673	0.235	641	0.223	85
Low NOx Burner Technology w/ Closed-coupled OFA	0.265	432	0.240	329	0.203	48
Low NOx Burner Technology w/ Separated OFA	0.218	501	0.194	475	0.185	79
Low NOx Burner Technology w/ Closed-coupled/Separated OFA	0.206	455	0.177	485	0.156	69

* Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2016

Current combustion control technology reduces NO_X formation through a suite of technologies. Whereas early combustion controls focused only on either Low NOx 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 multitude of burners and overfire air system(s) as a complete assembly have enabled suppliers to obtain better results than tuning individual components. For this regulation, the agency evaluated EGU NO_X reduction potential based on upgrading units to modern combustion controls. Combustion control upgrade paths are shown in Table 3-11 of the IPM 5.13 documentation (*see* Chapters 3 and 5 of the IPM documentation for additional information). 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 (or, Low NOx burners with Close-Coupled and Separated Overfire Air).

With the wide range of LNB configurations available and furnace types present in the fleet, the agency decided to assess compliance costs based on an illustrative unit. This was the same unit examined at proposal.[8] 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. In the final rule modeling, we observe that most of the NO_X reductions projected to occur from combustion control

[8] 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 an input uncontrolled NO_x rate of 0.50 lb NO_x / mmBtu initial rate and had a 41 percent NO_X removal efficiency after the combustion control upgrades. This 0.50 lbs/mmBtu input NO_x rate is comparable to the observed average rate of 0.48 lbs/mmBtu for the coal-fired wall-fired units from 2003-2008 that had not installed controls. This rate is exhibited by a number of coal fired units and EPA notes that there are still units with wall and tangentially-fired boilers which continued to have rates higher than 0.50 lbs/mmBtu in 2015. Using 2015 data for uncontrolled wall-fired coal units and comparing these rates against controlled units of the same type, EPA observes a 41% difference in rate. Similarly, EPA observes a 51% reduction for coal units with tangentially-fired boilers. To be conservative, EPA used the 41 percent reduction from wall-fired coal units.

retrofits occurred at units that were larger than the illustrative unit.[9] Accordingly, the agency calculated the costs for various combustion control paths. The cost estimates utilized the equations found in Table 5-4 "Cost (2011$) of NO_X Combustion Controls for Coal Boilers (300 MW Size)" from Chapter 5 of the IPM documentation.[10] For these paths, EPA found that the cost ranges from $430 to $1200 per ton NO_X removed ($2011). EPA examined lower capacity factors (i.e., 70%) and found the costs increased from $520 to $1,400 per ton. At lower capacity factors (i.e., 54.1%), costs increased to a max of $1,780 per ton for one type of installation. Examining the estimates for all of the simulations, the agency finds that the costs of combustion control upgrades typically fall below the costs for returning a unit with an inactive SCR to full operation (i.e., $1,400/ton), but in some cases, above the cost for returning a partially operating SCR to full operation (i.e., $800/ton). Consequently, EPA identifies $1,400/ton as the cost level where upgrades of combustion controls would be widely available and cost-effective.

Cost Estimates for Retrofitting with SCR and Related Costs

For coal-fired units, an SCR retrofit is the state-of-the-art technology used to limit NO_X emissions to their lowest extent. The agency examined the cost for newly retrofitting a unit with SCR technology. As was done at proposal, using the Sargent & Lundy cost tool to examine the costs of SCR retrofit for an illustrative unit, a 500 MW unit operating at an 85% percent capacity factor with an uncontrolled rate of 0.35 lb NO_X / mmBtu, retrofitted with an SCR to a lower emission rate of 0.07 lb NO_X / mmBtu, results in a compliance cost of $5,000 / ton of NO_X removed. For this illustrative unit, at lower capacity factors, costs increased. Consequently, SCR installation is most often seen for large units generating substantial electricity with high capacity factors. Because of the substantial capital cost required for retrofitting a unit with an SCR, owners with low utilized units may adopt SNCR as a more appropriate economical choice for NO_X control, thereby reducing the "cost per ton" for of NO_X reduction.

Cost Estimates for Retrofitting with SNCR and Related Costs

SNCR technology is an alternative method of NO_X emission control that incurs a much 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 a unit with SNCR technology using the Sargent & Lundy tool. The agency conservatively set the NO_X emission reduction rate at 25 percent. For the unit examined above (500 MW, 0.35 lbs NO_X/mmBtu) with a 42 percent capacity factor, the cost is $6,400 / ton of NO_X removed.

Feasibility Assessment: Implementation Timing for Each EGU NO_X Control Strategy

The agency evaluated the implementation time required for each compliance option to assess the feasibility of achieving reductions during the 2017 ozone season.

EPA evaluated the feasibility of turning on idled SCRs for the 2017 ozone season. The EGU sector is very familiar with restarting SCR systems. Based on past practice and the possible effort to restart the

[9] Generally, there is an inversely proportional relationship between cost of control and unit size (on a dollars per ton basis). That is, assuming a constant NO_X removal efficiency, more absolute tons of NO_X are removed as units increase in size while absolute capital costs increase at a lower rate. Thus, we would expect it may be even more cost-effective to control these units than has been assumed here.

[10] https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_emission_control_technologies_0.pdf

controls (e.g., re-stocking reagent, bringing the system out of protective lay-up, performing inspections), returning these idled controls to operation is possible within the compliance timeframe of this rule. This timeframe is informed by many electric utilities' previous, long-standing practice of utilizing SCRs to reduce EGU NO_X emissions during the ozone season while putting the systems into protective lay-up during non-ozone season months when the EGUs did not have NO_X emission limits that warranted operation of these controls. For example, this was the long-standing practice of many EGUs that used SCR systems for compliance with the NO_X Budget Trading Program. Based on the seasonality of EGU NO_X emission limits, it was typical for EGUs to turn off their SCRs following the September 30 end of the ozone season control period. They would then lay-up the pollution control for seven months of non-use. By May 1 of the following ozone season, the control would be returned to operation. In the 22 state CSAPR Update region, 2005 EGU NO_X emission data suggest that 125 EGUs operated SCR systems in the summer ozone season, likely for compliance with the NO_X Budget Trading program, while idling these controls for the remaining seven non-ozone season months of the year.[11] In order to comply with the seasonal NO_X limits, these SCR controls regularly were taken out of and put back into service within seven months.

Based on EGUs' past experience and the frequency of this practice of idling controls for periods of time, the EPA finds that idled controls can be restored to operation in less than seven months. The lead-time for compliance with this rule is longer than this timeframe.

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 described regarding 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.[12] 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 feasible for the 2017 ozone season. Increasing NO_X removal by SCR controls that are already operating can be implemented by procuring more reagent and catalyst. EGUs with SCR routinely procure reagent and catalyst as part of ongoing operation and maintenance of the SCR system. In many cases, where the EPA has identified EGUs that are operating their SCR at non-optimized NO_X removal efficiencies, EGU data indicates that these units historically have achieved more efficient NO_X removal rates. Therefore, the EPA finds that optimizing existing and SCR systems currently being operated could generally be done by reverting back to previous operation and maintenance plans. 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

[12] In the 22 state CSAPR Update region, 2005 EGU NO_X emissions data suggest that 125 EGUs operated SCR systems in the summer ozone season while idling these controls for the remaining 7 non-ozone season months of the year. Units with SCR were identified as those with 2005 ozone season average NO_X rates that were less than 0.12 lbs/mmBtu and 2005 average non-ozone season NO_X emission rates that exceeded 0.12 lbs/mmBtu and where the average non-ozone season NO_X rate was more than double the ozone season rate.

SCR, this may only require updating the frequency of deliveries. This may be accomplished within a few weeks or months.

Combustion control, 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 are reported in the TSD for that rulemaking entitled, "Installation Timing for Low NO_X Burners (LNB)", Docket ID No. EPA-HQ-OAR-2009-0491-0051.[13] Industry has demonstrated retrofitting LNB technology controls on a large unit (800 MW) in under six months. This TSD is in the docket for the CSAPR Update.

This rule does not consider retrofitting SCR or SNCR technology as a viable compliance option in the 2017 compliance timeframe. The time requirements for an SCR retrofit exceed 18 months from contract award through commissioning. SNCR is similar to activated carbon injection (ACI) and dry sorbent injection (DSI) installation and requires about 12 months from award through commissioning. Conceptual design, permitting, financing, and bid review require additional time. A detailed analysis for a single SCR system can be found in Exhibit A-3 and an ACI system (equivalent to an SNCR) in Exhibit A-5 in: "Final Report: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies", EPA-600/R-02/073, Oct 2002.[14] Note that EPA received comments that, in certain instances, individual SNCR installation could be done in 8 to 12 months from contract award. While EPA has not considered new SNCR installations to be a widely available EGU NO_X control strategy in establishing emission budgets, from both cost and compliance timing perspectives, some limited installations may be possible as a compliance option.

Shifting generation to lower NO_X- or zero-emitting EGUs, similar to operating existing post-combustion controls, uses investments that have already been made, can be done quickly, and can significantly reduce EGU NO_X emissions. 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 0.18 lb/mmBtu of NO_X across the 22 states included in the CSAPR Update in 2014. Similarly, generation could shift from uncontrolled coal to coal units that have SCR. 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, and EPA analyzed EGU NO_X reduction potential from this control strategy for the CSAPR Update.

Shifting generation to lower NO_X-emitting or zero-emitting EGUs occurs in response to economic factors. As the cost of emitting NO_X increases, combined with all other costs of generation, it becomes increasingly cost-effective for units with lower NO_X rates to increase generation, while units with higher NO_X rates reduce generation. Because the cost of generation is unit-specific, this generation shifting occurs incrementally on a continuum. Consequently, there is more generation shifting at higher cost NO_X levels. Because we have identified discrete cost thresholds resulting from the full implementation of particular types of emission controls, it is reasonable to simultaneously quantify the reduction potential

[13] http://www.epa.gov/airmarkets/airtransport/CSAPR/pdfs/TSD_Installation_timing_for_LNBs_07-6-10.pdf
[14] http://nepis.epa.gov/Adobe/PDF/P1001G0O.pdf

from generation shifting strategy at each cost level. Including these reductions is important, ensuring that other cost-effective reductions (e.g., fully operating controls) can be expected to occur.

As described in the preamble, EPA limited shifting generation to units with lower NO_X emission rates within the same state as a proxy for the amount of generation that could be shifted in the near-term (i.e., 2017).

To study the potential implications of the generation shifting projected to occur as a result of implementation of the CSAPR Update, EPA reviewed all shifts in generation that were projected to occur between the base case and the $1,400 per ton cost threshold scenario used for constructing state budgets (cost threshold case). The shifts in generation between the base and cost threshold cases happen on an economic basis, whenever shifting of generation will lead to lower overall costs given a NO_X price, and thus can be studied by comparing the threshold scenario and base case results.

EPA examined generation changes from the base case to the threshold scenario at the regional level in each of the major regions that encompass the 22 states covered by the rule. Table 2 shows the changes in generation from coal and natural gas in each of these regions. As the table shows, shifts in generation are minimal. Overall, the decrease in coal generation is matched by an increase in natural gas generation from combined cycle units, and both shifts are generally only around one half of one percent. Generally, combined cycle increases are comparable to coal decreases in terms of magnitude, but are slightly larger in percentage terms because the base generation from combined cycle generation is lower than coal.

The data in Table 2 show a small shift from coal generation to natural gas generation as a result of the cost to emit NO_X assumed in the cost threshold scenario. Table 3 shows generation shifting among coal units because coal units with higher NOx rates will incur higher costs compared to coal units with lower NOx rates when a cost to emit NO_X is imposed in the model. To examine these types of changes within the units of the coal fleet, EPA first classified units by the level of projected change and then compared the resulting generation. Units were classified by whether they had changes (increases or decreases) of more than 5 percent. The number of units and generation from these units were then analyzed to determine the contribution of units with larger changes as a percentage of the overall fleet and generation level. The results of this analysis are shown in Table 3.

The regional results in Tables 2 and 3 show that potential generation shifts resulting from the policy are small compared to the typical range of year-on-year variation in generation for the ozone season, and therefore that the shifts are fully feasible in the normal course of power system planning and dispatch operations. Table 4 shows total coal and gas ozone season generation over time, using generation data submitted to EPA's Clean Air Markets Division. The absolute year over year variation in generation from all sources, and particularly for coal units and gas units when viewed separately, is clearly larger than the variations expected as a result of the update rule.

Table 2: Regional Coal and Gas Generation Changes Base to Cost Threshold Case (2018, GWh)

	Coal Steam Plants				Combined Cycle Plants			
Region	**Base**	**Policy**	**Change**	**Percent Change**	**Base**	**Policy**	**Change**	**Percent Change**
ERCOT	52,318	51,855	-463	-0.9%	76,801	77,280	479	0.6%
MISO	113,211	112,184	-1,027	-0.9%	20,952	21,893	941	4.5%
PJM	138,870	139,841	971	0.7%	86,994	87,483	489	0.6%
SERC	90,171	89,489	-682	-0.8%	109,897	111,098	1,201	1.1%
SPP	33,705	33,246	-458	-1.4%	16,895	17,375	480	2.8%
Total	428,275	426,615	-1,660	-0.4%	311,539	315,129	3,590	1.2%

Table 3: Regional Changes for Coal Unit Generation from the Base to the Cost Threshold Case (2018, GWh)

		Units with Generation Increases Greater than 5%		Units with Generation Decreases Greater than 5%	
Region	**Generation from All Coal Units**	**Generation**	**Percent of All Generation**	**Generation**	**Percent of All Generation**
ERCOT	52,318	0	0.0%	473	0.9%
MISO	113,211	1,330	1.2%	2,427	2.1%
PJM	138,870	2,027	1.5%	2,514	1.8%
SERC	90,171	473	0.5%	426	1.1%
SPP	33,705	0	0.0%	481	1.4%
Total	428,275	3,829	0.9%	7,471	1.7%

Table 4: Historical Regional Coal and Gas Generation

Region	**2011 OS Generation (MWh)**	**2012 OS Generation (MWh)**	**2013 OS Generation (MWh)**	**2014 OS Generation (MWh)**	**2015 OS Generation (MWh)**	**Average Generation (MWh)**	**Avg Absolute Year by Year Percent Variation Relative to Average**
Coal and Gas Units							
ERCOT	139,056,059	131,017,786	134,609,803	131,050,654	133,810,294	133,908,919	3%
MISO	160,949,929	156,042,518	153,290,509	147,230,881	146,926,308	152,888,029	2%
PJM	229,450,597	221,741,383	208,027,957	199,406,847	203,781,613	212,481,679	4%
SERC	233,358,240	234,646,108	206,222,693	217,363,373	224,542,889	223,226,660	5%
SPP	97,941,842	98,084,372	89,549,899	84,083,357	82,857,267	90,503,347	4%
Coal Units							
ERCOT	65,038,747	56,554,882	63,224,502	61,517,184	54,402,901	60,147,643	10%
MISO	148,334,711	133,249,813	140,020,963	136,262,295	128,886,797	137,350,916	6%
PJM	184,721,925	158,866,391	154,847,790	141,913,576	127,455,196	153,560,976	9%
SERC	148,516,082	127,689,539	121,980,881	127,428,908	114,298,673	127,982,817	8%
SPP	62,722,427	58,935,064	59,850,375	58,832,359	52,854,669	58,638,979	5%
NGCC Units							
ERCOT	61,802,830	64,931,240	63,193,163	61,164,396	70,188,494	64,256,025	6%
MISO	9,504,516	17,786,818	9,889,392	8,849,343	14,562,007	12,118,415	52%
PJM	36,865,556	53,442,540	46,836,760	50,831,308	64,972,340	50,589,701	23%
SERC	65,269,995	83,971,104	69,413,532	75,766,788	90,487,154	76,981,715	19%
SPP	18,208,854	23,909,298	17,328,211	17,373,825	21,751,986	19,714,435	21%

Feasibility Assessment: Historical Emissions Analysis to Show Compliance with Budgets

As an independent check to demonstrate EGUs' ability to comply with the CSAPR Update Rule requirements, EPA created an emissions assessment based on each unit's historical emissions. This assessment uses historical ozone season emissions to assess compliance feasibility independent of IPM modeling conducted to evaluate the rule. EPA created state-level emission estimates starting with reported unit level 2015 ozone season NO_X emissions. Committed (i.e., already announced) controls and upgrades were accounted for along with historical NO_X rates for units with existing SCRs and SNCRs. Known retirements were also included. EPA accounted for the "retired" heat input, by adding back in a comparable amount of heat input assumed to be combusted at each state's average emission rate after previous steps have been accounted for. Table 5 shows the emission estimates, by state. Column 7 shows the results of the bottom-up engineering analysis (before accounting for state-of-the-art combustion controls, or SOA CC). The totals accounting for SOA CC can be found in column 8. Each of the columns can be compared with the budgets in column 11. Comparing columns 10 and 11, for each state, the larger value is highlighted in red. The columns in Table 5 are as follows:

(1) 2015 reported unit-level ozone season NO_X emissions were summed to the state level
(2) Emissions associated with units committed to retire before January 1, 2017 were removed
(3) Emissions associated with units committed to convert from coal to gas before January 1, 2017 were reduced by 50 percent
(4) Emissions associated with units committed to add SCR before January 1, 2017 were reduced to a NO_X rate of 0.075 lb/mmBtu
(5) Emissions associated with units committed to add SOA CC before January 1, 2017 were reduced to a NO_X rate appropriate tor the individual unit
(6) Emissions associated with units that added an SCR in 2014 or 2015 were reduced to a NO_X rate of 0.075 lb/mmBtu
(7) Emissions associated with units with an existing SCR were reduced to a NO_X rate equivalent to the unit's third lowest historical ozone season NO_X rate, if that NO_X rate was lower than the unit's 2015 NO_X rate
(8) Emissions associated with units able to install SOA CC before the beginning of the 2017 ozone season period were reduced to a NO_X rate appropriate for the individual unit
(9) Emissions associated with units with an existing SNCR were reduced to a NO_X rate equivalent to the unit's third lowest historical ozone season NO_X rate, if that NO_X rate was lower than the unit's 2015 NO_X rate[15]
(10) As generation associated with retired units will need to be replaced, the heat input from retired units [in (2), above] is added to each state using the further updated state level NO_X rate at the end of (9)
(11) Each state's bottom-up analysis at the end of (10) is compared to the final CSAPR Update Rule State budgets

EPA found that after aggregating all states at the regional level, this bottom-up analysis shows that sources are about 3 percent below the sum of the CSAPR Update Rule state budgets and all states are individually below their assurance levels. This assessment confirms EPA's determination that EGUs can

[15] Although EPA did not consider the operation of idled SNCR in calculating the budgets finalized in the CSAPR Update, EPA finds that the operation of these controls is feasible by the 2017 and therefore represent a valid compliance option for EGUs subject to the CSAPR Update. As Table 5 (column 9) demonstrates, the emissions reductions associated with SNCR controls are small relative to emissions reductions achievable via other control strategies and EGUs can comply with the requirements of the CSAPR Update even without operation of SNCR.

collectively achieve the budgets finalized in the CSAPR Update by implementing a variety of control strategies that can be implemented by the 2017 ozone season.

Sources can also comply with the requirements of the CSAPR Update without implementing all of the control strategies listed above. By way of example, in Table 6, EPA compared the compliance value where sources fully operate all existing SCR controls (column 7) along with the incremental emissions associated with adding back in heat input from retired units with the budgets at this intermediate step (column 12). Aggregating all states at the regional level in this analysis, EPA finds a total of 319,377 tons which is under 1% above the total of the regional final budget (column 11) and all states are within the 21% variability limits. Given the bank of additional allowances that will be available for the 2017 compliance period, this means that sources can fully comply with the requirements of the CSAPR Update without any capital expenditures by simply turning on and operating all existing SCR controls at historical levels.

As we have demonstrated above, generation shifting provides an additional feasible method of compliance. This bottom-up analysis did not include this generation shifting, which would decrease the emissions even further.

Table 5. Bottom-Up Analysis to Show Compliance Feasibility

State	(1) 2015 NOx (tons)	(2) Retired Before 2017 (tons)	(3) Coal to Gas Conversion (tons)	(4) New SCRs (Committed) (tons)	(5) New SOA CC (Committed) (tons)	(6) SCRs Completed for 2015 Adjusted to 0.075 lbs/mmBtu (tons)	(7) 3nd Lowest OS NOx Rate with 2015 Heat Input for Existing SCRs (or 2015 NOx Rate if Lower) (tons)	(8) $1,400 SOA CC (Remedy Case) (tons)	(9) 3nd Lowest OS NOx Rate with 2015 Heat Input for Existing SNCRs (or 2015 NOx Rate if Lower) (tons)	(10) Retired Heat Input Added Back At Remaining State NOx Rate (tons)[2]	(11) Final CSAPR Update Rule EGU NO_X Emission Budgets (tons)
Alabama	20,369	16,140	14,073	14,073	14,073	14,073	13,038	12,689	12,678	13,673	13,211
Arkansas [1]	12,560	12,560	12,560	12,560	12,560	12,560	12,550	8,362	8,362	8,362	12,048
Georgia	10,786	8,602	8,602	8,602	8,602	8,602	8,244	8,139	8,139	8,291	8,481
Illinois	15,976	15,976	15,116	15,116	14,850	14,850	13,907	13,907	13,892	13,892	14,601
Indiana	36,353	35,560	34,476	31,042	31,042	31,042	25,374	25,050	25,050	25,325	23,303
Iowa	12,178	11,407	11,140	11,140	11,140	11,140	11,082	10,743	10,743	11,070	11,272
Kansas	8,136	7,751	7,736	7,736	7,736	7,565	7,556	7,556	7,556	7,845	8,027
Kentucky	27,731	26,513	25,826	25,826	25,826	25,826	21,316	21,062	20,871	21,269	21,115
Louisiana	19,257	19,253	19,098	19,098	19,098	19,098	19,062	18,337	18,247	18,250	18,639
Maryland	3,900	3,855	3,855	3,855	3,855	3,855	3,805	3,805	3,799	3,815	3,828
Michigan	21,530	16,854	16,854	16,854	16,854	16,854	16,811	15,966	15,960	17,960	17,023
Mississippi	6,438	6,438	6,438	6,438	6,438	6,438	6,394	6,296	6,296	6,296	6,315
Missouri	18,855	18,533	18,325	18,325	18,325	18,325	16,372	16,372	16,221	16,326	15,780
New Jersey	2,114	2,114	2,114	2,114	2,114	2,114	2,049	2,049	2,048	2,048	2,062
New York	5,593	5,489	5,489	5,489	5,489	5,489	5,365	5,365	5,365	5,406	5,135
Ohio	27,382	27,269	27,269	27,269	27,269	27,269	18,129	17,080	16,412	16,481	19,522
Oklahoma	13,922	13,055	13,055	13,055	13,055	13,055	13,053	12,382	12,382	13,039	11,641
Pennsylvania	36,033	36,033	35,607	35,607	35,607	32,934	17,465	17,465	17,262	17,262	17,952
Tennessee	9,201	9,201	9,201	9,201	7,779	7,779	6,817	6,569	6,569	6,569	7,736
Texas	55,409	54,441	54,441	54,441	54,441	54,441	53,245	52,504	52,265	52,647	52,301
Virginia	9,651	9,618	9,357	9,357	9,357	9,357	9,229	8,690	8,661	8,670	9,223
West Virginia	26,937	26,785	26,785	26,785	26,785	26,785	13,090	12,661	12,195	12,236	17,815
Wisconsin	9,072	8,347	8,273	7,726	7,726	7,726	7,640	7,640	7,603	7,813	7,915
CSAPR Update Region (no GA)	398,596	383,190	377,088	373,106	371,418	368,573	313,349	302,549	300,437	306,252	316,464

[1] For Arkansas, the state's 2017 budget is shown. Their final budget (2018 and beyond) is 9,210 tons.
[2] Reductions from generation shifting are not included in this bottom-up analysis

Table 6. Bottom-Up Analysis to Show Compliance Feasibility by Stopping at Step 7, Operating Existing SCR Controls at Historic Rates[1]

State	(7) 3nd Lowest OS NOx Rate with 2015 Heat Input for Existing SCRs (or 2015 NOx Rate if Lower) (tons)	(12) Retired Heat Input Added Back at Remaining State NOx Rate at this Intermediate Step (tons)	(11) Final CSAPR Update EGU NO_X Emission Budgets (tons)	(13) Intermediate Compliance Feasibility vs Final CSAPR Update Budgets (%)
Alabama	13,038	14,062	13,211	-6%
Arkansas	12,550	12,550	12,048	-4%
Georgia	8,244	8,398	8,481	1%
Illinois	13,907	13,907	14,601	5%
Indiana	25,374	25,652	23,303	-10%
Iowa	11,082	11,419	11,272	-1%
Kansas	7,556	7,845	8,027	2%
Kentucky	21,316	21,723	21,115	-3%
Louisiana	19,062	19,065	18,639	-2%
Maryland	3,805	3,822	3,828	0%
Michigan	16,811	18,919	17,023	-11%
Mississippi	6,394	6,394	6,315	-1%
Missouri	16,372	16,477	15,780	-4%
New Jersey	2,049	2,049	2,062	1%
New York	5,365	5,406	5,135	-5%
Ohio	18,129	18,206	19,522	7%
Oklahoma	13,053	13,745	11,641	-18%
Pennsylvania	17,465	17,465	17,952	3%
Tennessee	6,817	6,817	7,736	12%
Texas	53,245	53,634	52,301	-3%
Virginia	9,229	9,239	9,223	0%
West Virginia	13,090	13,134	17,815	26%
Wisconsin	7,640	7,851	7,915	1%
CSAPR Update Region (no GA)	313,349	319,377	316,464	-1%

[1] Data in Table 6 include replicates of Table 5 (columns 7 and 11) with additional comparisons (columns 12 and 13).

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 / ton NO_x	Urea cost	Cost / ton NO_x
1999	$ 190	$ 108	$ 165	$ 165
2000	$ 209	$ 118	$ 194	$ 194
2001	$ 385	$ 218	$ 277	$ 277
2002	$ 228	$ 129	$ 179	$ 179
2003	$ 374	$ 212	$ 258	$ 258
2004	$ 366	$ 207	$ 264	$ 264
2005	$ 394	$ 223	$ 319	$ 319
2006	$ 489	$ 277	$ 345	$ 345
2007	$ 500	$ 283	$ 445	$ 445
2008	$ 731	$ 414	$ 537	$ 537
2009	$ 640	$ 363	$ 450	$ 450
2010	$ 474	$ 269	$ 421	$ 421
2011	$ 744	$ 422	$ 501	$ 501
2012	$ 812	$ 460	$ 547	$ 547
2013	$ 877	$ 497	$ 574	$ 574
2014	$ 888	$ 503	$ 550	$ 550

USDA

http://www.neo.ne.gov/statshtml/181.htm