

US EPA ARCHIVE DOCUMENT

Technical Support Document
for the
Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone
(Clean Air Interstate Rule):
Reconsideration Notice of Proposed Rule

**Impact on CAIR Analyses of D.C. Circuit Decision in
New York v. EPA**

EPA Docket number: OAR-2003-0053
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U.S. Environmental Protection Agency
Office of Air and Radiation

Overview

This technical support document (TSD) supplements the discussion of the impact on Clean Air Interstate Rule (CAIR) analyses of the D.C. Circuit Decision in New York v. EPA in the Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule): Supplemental Notice of Reconsideration (“Supplemental Notice”).

This TSD discusses the following analyses:

- Potential for collateral increases in NSR-regulated air pollutants from use of nitrogen oxides (NO_x) and sulfur dioxide (SO₂) controls for CAIR
- Costs of sulfur trioxide (SO₃)/ sulfuric acid (H₂SO₄) mitigation
- Boilermaker labor and installation timing analysis for SO₃/H₂SO₄ controls

The following additional materials have been placed in the docket:

- Integrated Planning Model (IPM) runs for marginal cost analysis
- Parsed files showing retrofits and coal choice information on a unit-specific basis
- Parsed data for the CAIR-Clean Air Mercury Rule (CAMR)-Clean Air Visibility Rule (CAVR) regulatory scenario in 2007
- Boilermaker calculations

Analysis of Potential for Collateral Increases in Air Pollutants from Use of NO_x and SO₂ Controls for CAIR

As discussed in the Supplemental Notice, the Agency examined the potential for collateral increases in New Source Review¹ (NSR)-regulated air pollutants from the types of NO_x and SO₂ controls on which EPA based its CAIR cost-effectiveness determination. The EPA considered each of the NO_x and SO₂ control measures that were included in the CAIR cost-effectiveness determination and found that the following technologies may have the potential to cause collateral increases in air pollutants regulated under NSR: combustion controls, selective catalytic reduction (SCR), flue gas desulfurization (FGD), and fuel switches to low sulfur coal. This TSD provides supplemental information to the discussion in the Supplemental Notice.

Increases in Sulfuric Acid or Particulate Matter Emissions from Selective Catalytic Reduction (SCR) Retrofits

The Supplemental Notice discusses the potential for sulfuric acid emissions increases from SCR retrofits. This TSD provides additional information to support the Supplemental Notice.

¹ Prevention of Significant Deterioration (PSD) is the part of the NSR program that applies to sources located in areas in attainment with the NAAQS. Unless otherwise noted, in this document, when we refer to the NSR program, NSR review, NSR permitting or other NSR requirements, we are referring to both the NSR and PSD programs and their respective requirements.

Technical Support Document: Impact on CAIR Analyses of D.C. Circuit Decision in New York v. EPA

The SCR technology involves injection of a reagent, ammonia, into boiler flue gas. A catalyst is used to promote reaction between ammonia and NO_x present in flue gas, forming harmless nitrogen and water. There are two secondary effects associated with SCR that may result in the formation of additional sulfur trioxide (SO₃) and particulate matter (PM).

A small portion of ammonia in SCR remains unreacted and is present in flue gas at the catalyst reactor outlet as ammonia slip. In addition, the SCR catalyst oxidizes a portion of the SO₂ present in flue gas to SO₃. The amount of SO₃ increase depends on the coal sulfur content and the characteristics of the SCR catalyst. The total amount of SO₃ present is generally greater than that of ammonia, since SO₃ is also formed within the boiler via oxidation of fuel sulfur. This condition favors a reaction between SO₃ and ammonia that produces ammonium bisulfate, which condenses to form solid PM.⁽¹⁾

Recent SCR technology developments have emphasized minimization of ammonia slip and SO₂-to-SO₃ conversion levels. The new SCR installations are routinely being designed to maintain ammonia slip at two to three ppmv level.⁽¹⁻⁷⁾ Similarly, SO₂-to-SO₃ conversion rates for SCR have been kept at less than one percent (typically 0.5 percent or lower). In comparison, the SO₂-to-SO₃ conversion rate that occurs in the boiler itself is about 1.0 percent.

The EPA used the above ammonia slip and SO₃ levels to determine the amount of PM that could potentially be formed as ammonium bisulfate. For a 500 MW unit, the 3 ppmv of ammonia slip and SO₃ present in flue gas result in the formation of approximately 208 tons per year of PM as ammonium bisulfate. The majority of this PM will be captured in the particulate control device installed at this unit. For a unit equipped with a baghouse, minimal increase in the stack PM emission is expected, as virtually all of the increased PM should be captured in the baghouse. For a unit equipped with an electrostatic precipitator (ESP), it is estimated that the increase in the PM or PM₁₀ emission will be approximately 3.1 tons per year, which is well below the level that would trigger a NSR review. This estimate uses a particulate collection efficiency of 98.5 percent, which is the average efficiency of the ESP installed at the coal-fired units in the U.S.⁽⁸⁾

The SCR operation results in an increase in the flue gas SO₃ concentration. The majority of this SO₃ is expected to react with the moisture in flue gas to form sulfuric acid (H₂SO₄). The amount of SO₃/H₂SO₄ added to the flue gas stream by SCR will be directly proportional to the fuel sulfur content and will depend on the characteristics of the SCR catalyst. A unit that installs SCR-only (that is, does not also install a technology to mitigate SO₃/H₂SO₄) could increase sulfuric acid emissions significantly enough to trigger the NSR threshold of 7 tons per year for sulfuric acid mist.²

However, if the unit switches to a low sulfur coal when installing SCR, the unit would not increase sulfuric acid emissions enough to trigger the threshold. Making the conservative assumption that a unit would choose a coal with only a 50 percent lower sulfur content when

²The Agency's analysis for the Supplemental Notice of Reconsideration assumes that all sulfuric acid emitted will be counted as emission of sulfuric acid mist, which is an NSR-regulated pollutant.

Technical Support Document: Impact on CAIR Analyses of D.C. Circuit Decision in New York v. EPA installing SCR (in reality, sources might choose a reduction in coal sulfur content greater than 50 percent), this reduction in coal sulfur content would be sufficient to reduce the amount of SO₃ generated in the boiler such that the net change in SO₃ would be insufficient to trigger the 7 tons per year sulfuric acid mist NSR threshold. Assuming that 1.0 percent of SO₂ is converted to SO₃ in the boiler and an additional 0.5 percent is converted in the SCR, a total of about 1.5 percent of SO₂ present in the fuel is converted to SO₃. If the fuel SO₂ content is reduced by 50 percent at the same time the SCR is installed, the net result would be that the SO₂-to-SO₃ conversion rate (including conversion occurring in both the boiler and the SCR) would be 75 percent of what the conversion was before the changes (i.e., before retrofitting the SCR and switching to the lower sulfur coal).

Impact of Flue Gas Desulfurization (FGD) on Sulfuric Acid Emissions for Units that Retrofit SCR

The two most common FGD systems used for SO₂ control include a lime-based spray dryer system (dry FGD) and a limestone-based wet FGD system (wet FGD). In each system, the reagent is injected into the flue gas stream in the form of slurry, causing a considerable drop in the flue gas temperature. Therefore, a strong potential exists for any SO₃/H₂SO₄ present in flue gas to condense to acid mist.

These FGD systems are effective at reducing SO₃/H₂SO₄ emissions. More than 90 percent of SO₃/H₂SO₄ is removed in a dry FGD, while up to about 50 percent removal occurs in a wet FGD system. Considering the effectiveness of FGD systems at mitigating SO₃/H₂SO₄, the Agency expects that a unit installing SCR and FGD (wet or dry) at the same time would not increase sulfuric acid emissions significantly enough to trigger NSR.

A unit that retrofits dry FGD at the same time as SCR would yield a substantial net decrease in sulfuric acid emissions because the dry FGD captures more than 90 percent of SO₃/H₂SO₄. A unit that retrofits wet FGD at the same time as SCR might have a small increase in sulfuric acid emissions, but such an increase would not be sufficient to trigger the NSR threshold. EPA assumes that the SO₂-to-SO₃ conversion rate in the boiler and SCR are about 1.0 percent and 0.5 percent, respectively. Taking a 90 percent reduction (in the case of dry FGD) brings the total SO₃ down to well below the rate before installing SCR (i.e., a 90 percent reduction from 1.5 is less than 1.0). Assuming about a 50 percent reduction (in the case of wet FGD) also brings the total SO₃ down to less than the rate before installing SCR (i.e., a 50 percent reduction from 1.5 is less than 1.0).

Sulfuric acid emissions could increase enough to trigger NSR if, after installing a wet FGD, a power company switched to burning a higher sulfur coal. Assuming that a company switched from 1 lb/MMBtu coal to 5 lb/MMBtu coal, SO₃/H₂SO₄ emissions would increase by a factor of five (assuming that the coal switch did not impact the SO₃ conversion rate in the boiler).

Impact of Wet Electrostatic Precipitator (ESP) on Sulfuric Acid Emissions

One potential control technology that could be used to mitigate SO₃/H₂SO₄ emissions is a wet ESP. A wet ESP removes approximately 95% of the SO₃/H₂SO₄ emissions.

As explained above, installing a SCR is likely to less than double SO₃/H₂SO₄ emissions from a coal-fired boiler (assuming an SO₃ conversion rate of 1% in the boiler and an additional 0.5% from the SCR catalyst). Therefore, if there were no other changes (e.g. coal switching) installation of a wet ESP would reduce SO₃/H₂SO₄ emissions substantially below the level emitted from a unit before the SCR was installed.

As explained above, switching to a higher sulfur content coal at the same time as installing a wet FGD could lead to SO₃/H₂SO₄ emissions increasing by a factor of five. Even without considering the SO₃/H₂SO₄ emission reductions from the FGD itself, the wet ESP would reduce SO₃/H₂SO₄ emissions substantially below the level emitted from a unit before the FGD was installed and the coal switch took place.

If a company installed both an SCR and a wet FGD and switched from 1 lb/MMBtu coal to 5 lb/MMBtu coal, SO₃/H₂SO₄ emissions would increase by a factor of ten, assuming that the coal switch did not impact the SO₃ conversion rate in the boiler (the factor of ten increase is based on a very conservative assumption of a 1% SO₂-to-SO₃ conversion rate in the SCR), and without considering SO₃/H₂SO₄ emission reductions from the FGD. Considering the removal efficiency of the wet ESP, the wet ESP would reduce SO₃/H₂SO₄ emissions substantially below the level emitted from a unit before the FGD was installed and the coal switch took place (without even considering the SO₃/H₂SO₄ reductions from the FGD itself).

Increases in Carbon Monoxide (CO) and Unburned Carbon (Solid Particulate) Emissions from Combustion Controls

The Supplemental Notice discusses increases in CO and unburned carbon from combustion controls. This TSD provides additional information to support the information in the Supplemental Notice.

The NO_x removal efficiency for each type of combustion control used in EPA's analysis for CAIR was estimated as an average of the reported efficiencies for a large number of units equipped with these controls. In a unit equipped with both low-NO_x burner (LNB) and overfire air (OFA) technologies, LNB provides a greater part of the overall NO_x removal reduction. Since the NO_x removal efficiencies used in EPA's analysis are not aggressive, it is believed that the units installing combustion controls can opt for moderate levels of OFA flow rates and still achieve the NO_x reduction levels projected in EPA's analysis, without causing significant increases in the CO and unburned carbon emissions.

Analysis of SO₃/H₂SO₄ Mitigation Costs for CAIR SCR and/or Wet FGD Projects

The following information supplements information on SO₃/H₂SO₄ mitigation costs presented in the Supplemental Notice.

The EPA used the Integrated Planning Model (IPM)³ to provide an estimate of the possible cost impacts for CAIR units that may install SO₃/H₂SO₄ controls. For the reasons stated in the Supplemental Notice, EPA believes that its analysis overstates the likely true cost impact. As discussed in the Supplemental Notice, EPA analyzed the cost impacts of SO₃/H₂SO₄ mitigation by conducting an IPM sensitivity analysis in which we added costs for wet ESP to every unit that installs SCR and/or wet FGD.⁴ Table 3 presents the results of the SO₃/H₂SO₄ mitigation sensitivity analysis. The Supplemental Notice discusses these results in detail.

The EPA estimated the costs of wet ESP for use in the SO₃/H₂SO₄ sensitivity analysis. The costs used in the analysis are as follows (9-11):

For a 500 MW unit:

Capital cost: \$40/kW

Fixed O&M: \$0.71/kW-yr

Variable O&M: 0.054 mills/kWh

Scaling factor for capital and fixed O&M cost: $(500/\text{MW})^{0.3}$

Variable O&M applies to all unit sizes - no scaling factor

Table 1: SO₂ and NO_x Estimated Marginal Cost (1999\$ per ton)¹

	SO ₂ Annual		NO _x Annual	
	2010	2015	2009	2015
Sensitivity analysis with SO ₃ /H ₂ SO ₄ mitigation (based on CAIR/CAMR/CAVR modeling)	\$700	\$900	\$1,600	\$2,000

¹ EPA IPM modeling is available in the docket. Projected costs are rounded to the nearest hundred dollars.

Marginal Cost Curves

In our analysis for the final CAIR, the Agency developed marginal cost curves to examine the changes in marginal costs for EGUs at varying levels of SO₂ and NO_x emission reductions.

³ The IPM is a multiregional, dynamic, deterministic linear programming model of the U.S. electric power sector. The Agency uses IPM to examine costs and, more broadly, to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous States and the District of Columbia.

⁴ Although EPA based this analysis on installation of wet ESP, the Agency is not making any determination or prediction regarding what the specific NSR requirements might be for these projects. While the Agency believes that only a subset of units installing SCR and/or wet FGD will, in fact, have increases in SO₃/H₂SO₄ that warrant the installation of wet ESP, due to the limitations of the IPM model, EPA made the conservative assumptions that all such units will install wet ESP.

Technical Support Document: Impact on CAIR Analyses of D.C. Circuit Decision in New York v. EPA These curves were presented in the final CAIR (70 FR 25204-25213)⁵. The EPA used the marginal cost curve analysis to corroborate its finding concerning the cost effectiveness of CAIR emission reductions. All dollar values are reported in 1999\$.

The Agency developed the marginal cost curves using the Technology Retrofit and Updating Model (TRUM), a model that selects investment options and dispatches generation to meet electricity demand. For simplicity, TRUM was developed as a steady-state, single-region spreadsheet model supported by Visual Basic for Applications (VBA) code. The TRUM consists of a set of sample generating units with varying characteristics. The mix of generation types and sizes was chosen to mirror, in general terms, the nationwide mix of capacities. The TRUM relies on the same underlying data as IPM. The Agency described its use of TRUM in a TSD for the final CAIR entitled “Modeling of Control Costs, Emissions, and Control Retrofits for Cost Effectiveness and Feasibility Analyses,” March 2005, as well as in a memo entitled “Analysis of the Marginal Cost of SO₂ and NO_x Reductions,” January 28, 2004 (the TSD and memo are both available in the CAIR docket (EPA-HQ-OAR-2003-0053)).

As part of our analysis for the Supplemental Notice, EPA developed marginal cost curves based on the IPM sensitivity analysis with SO₃/H₂SO₄ mitigation, to examine the changes in marginal costs for EGUs at varying levels of SO₂ and NO_x emission reductions with the added costs of SO₃/H₂SO₄ mitigation. Marginal cost curves based on the SO₃/H₂SO₄ sensitivity for SO₂ reductions in 2010 and 2015 and NO_x reductions in 2010 and 2015 are shown in Figures 1, 2, 3 and 4, respectively.

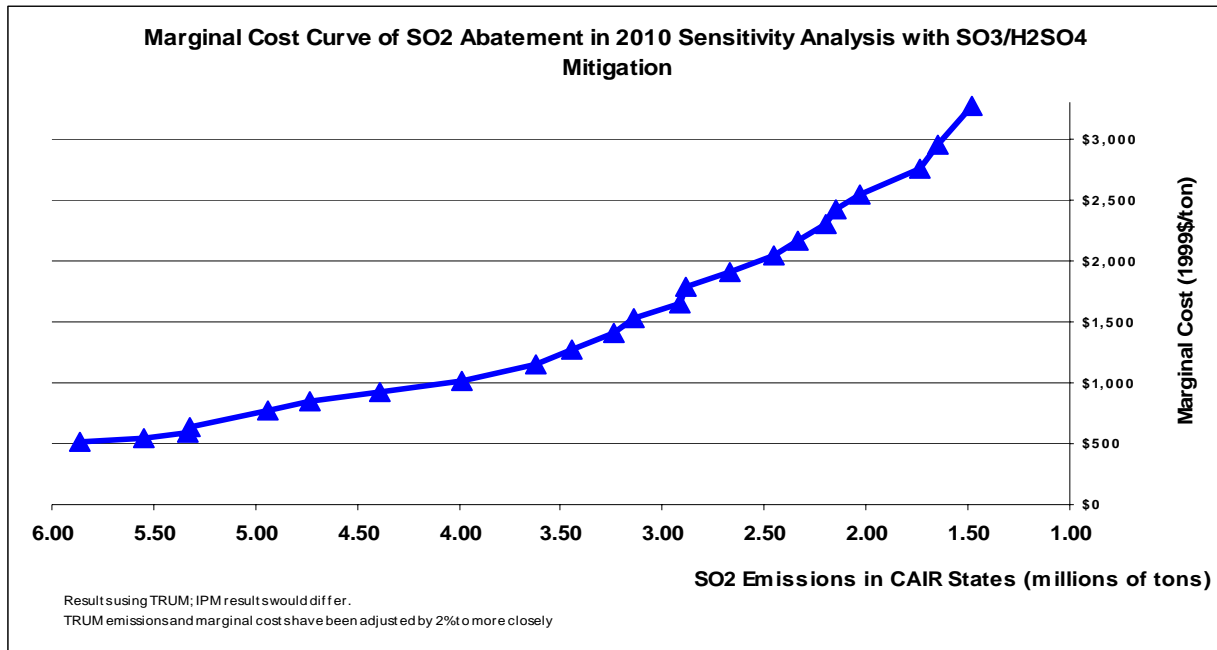
Figure 1 shows that the “knee” in the 2010 marginal SO₂ cost curve – the point where the cost of controlling a ton of SO₂ from EGUs is increasing at a noticeably higher rate – appears to occur at higher than \$2,500 per ton of SO₂ reduced. Figure 2 shows that the “knee” in the 2015 marginal SO₂ cost curve appears to occur at about \$2,000 per ton of SO₂ reduced. The projected marginal costs for this sensitivity analysis are \$700 per ton in 2010 and \$900 per ton in 2015, as shown in Table 3. For both 2010 and 2015, the marginal costs in the SO₃/H₂SO₄ sensitivity analysis are below the points at which the costs begin to increase at a significantly higher rate in the respective marginal cost curves.

Figure 3 shows that the “knee” in the 2010 marginal NO_x cost curve appears to occur at about \$2,500 per ton of NO_x reduced. Figure 4 shows that the “knee” in the 2015 marginal NO_x cost curve appears to occur at about \$2,000 per ton of NO_x reduced. The projected marginal costs for this sensitivity analysis are \$1,600 per ton in 2010 and \$2,000 per ton in 2015, as shown in Table 3. For both 2010 and 2015, the marginal costs in the SO₃/H₂SO₄ sensitivity analysis are not

⁵ As explained in the final CAIR, EPA used the marginal cost curve analysis solely to corroborate its findings concerning cost effectiveness of CAIR emission reductions. The marginal cost curve reflects only emissions reduction and cost information, and not other considerations. We note that it might be reasonable in a particular regulatory action to require emissions reductions past the knee of the curve to reduce overall costs of meeting the NAAQS or to achieve benefits that exceed costs. It should be noted that similar analysis for other source categories may yield different curves.

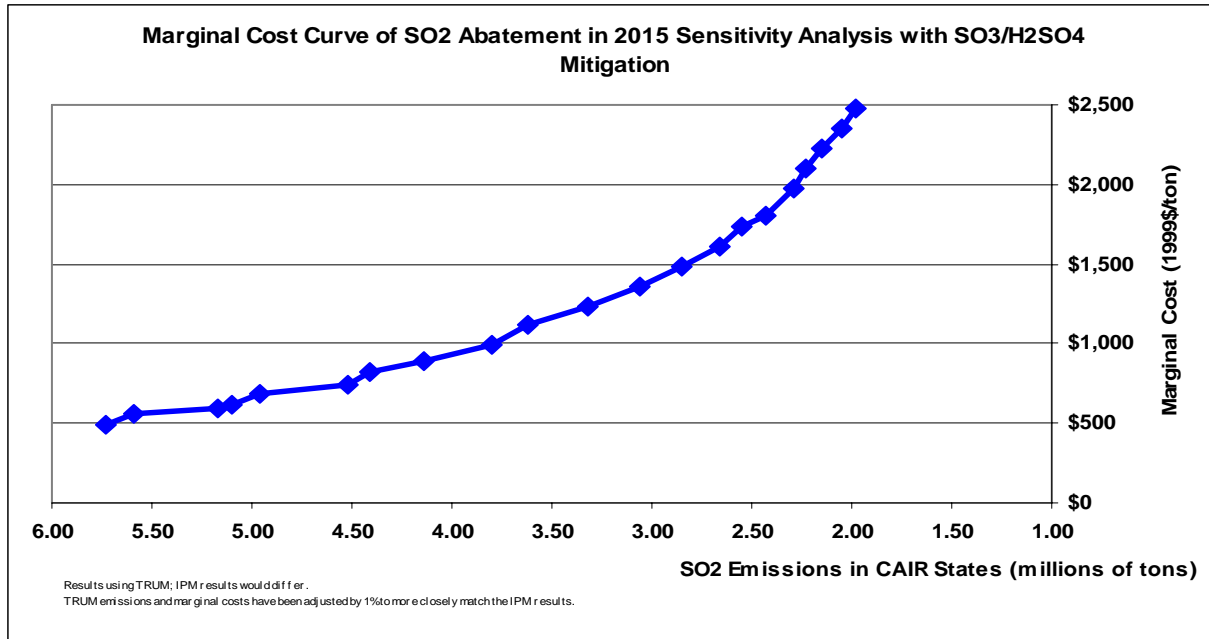
Technical Support Document: Impact on CAIR Analyses of D.C. Circuit Decision in *New York v. EPA* above the points at which the costs begin to increase at a significantly higher rate in the respective marginal cost curves.

As was the case in the final CAIR, the Agency is using marginal cost curve analyses solely to corroborate its findings concerning cost effectiveness of CAIR emission reductions in the SO₃/H₂SO₄ mitigation sensitivity.



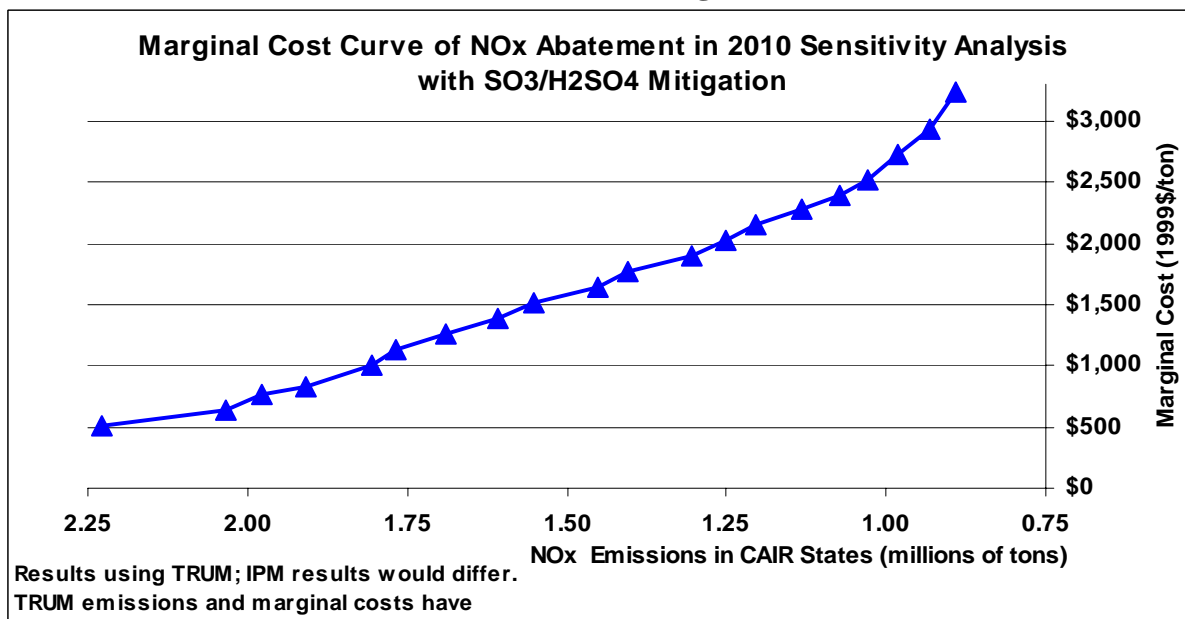
(Source: EPA, TRUM Model Analysis, 2005)

Figure 1: Marginal Cost Curve of SO₂ Abatement in 2010 Sensitivity Analysis with SO₃/H₂SO₄ Mitigation



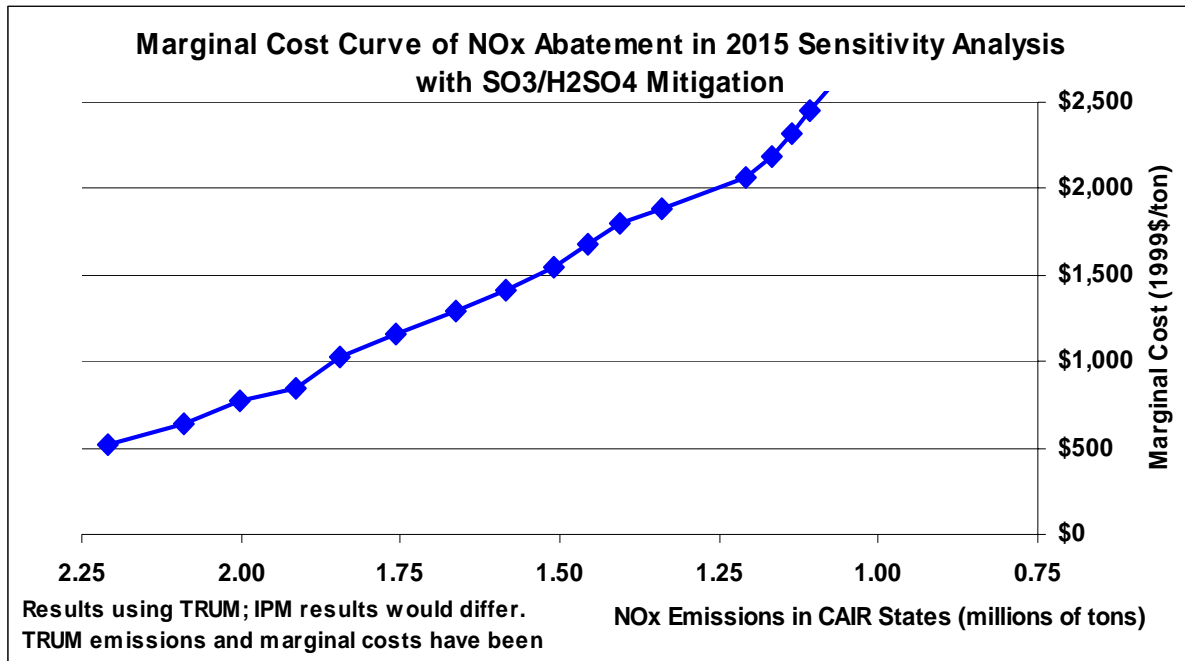
(Source: EPA, TRUM Model Analysis, 2005)

Figure 2: Marginal Cost Curve of SO₂ Abatement in 2015 Sensitivity Analysis with SO₃/H₂SO₄ Mitigation



(Source: EPA, TRUM Model Analysis, 2005)

Figure 3: Marginal Cost Curve of NO_x Abatement in 2010 Sensitivity Analysis with SO₃/H₂SO₄ Mitigation



(Source: EPA, TRUM Model Analysis, 2005)

Figure 4: Marginal Cost Curve of NOx Abatement in 2015 Sensitivity Analysis with SO3/H2SO4 Mitigation

Boilermaker Labor and Installation Timing Analysis for SO3/H2SO4 Controls

For the CAIR final rule, the Agency analyzed boilermaker labor availability for installing NOx and SO2 retrofits for CAIR, as discussed in the CAIR preamble (70 FR 25215-25225) and in a TSD entitled “Boilermaker Labor and Installation Timing Analysis,” OAR-2003-0053-2092 (“final CAIR boilermaker TSD”). For the Supplemental Notice, EPA completed an analysis to determine the impact of installing SO3/H2SO4 controls on boilermaker labor availability during the two CAIR phases. This TSD provides additional information regarding EPA’s boilermaker labor analysis for SO3/H2SO4 controls.

EPA examined the impact of installing wet ESP on the availability of boilermaker labor during the time when control retrofits will be installed for the two CAIR phases. EPA’s analysis assumed that units that might experience sulfuric acid emission increases greater than the sulfuric acid mist NSR threshold while incorporating NOx and/or SO2 controls for CAIR would choose to install wet ESP (a very conservative assumption because SO3/H2SO4 mitigation measures are available that would require less boilermaker labor than wet ESP). For this boilermaker labor analysis, the Agency used the same assumptions regarding boilermaker availability factors (i.e., boilermaker sources, population, average annual work hours, activity periods, and duty rates) that the Agency used in the boilermaker analysis for the final CAIR.

Technical Support Document: Impact on CAIR Analyses of D.C. Circuit Decision in New York v. EPA
These factors are defined in the final CAIR boilermaker TSD.

EPA conducted boilermaker analysis based on the following three scenarios. The CAIR examined boilermaker labor requirements for NO_x and SO₂ control retrofits based on these same three scenarios:

1. CAIR Phase I Policy Case. This scenario examines boilermaker labor requirements for the initial CAIR phase (2009 for NO_x and 2010 for SO₂).
2. Modified CAIR Phase I Policy Case. This scenario also examines boilermaker labor requirements for the initial CAIR phase (2009 for NO_x and 2010 for SO₂). However, this scenario is based on EIA assumptions for electricity demand and natural gas prices and UARG assumptions for boilermaker duty rates (UARG submitted assumptions for boilermaker duty rates during the CAIR comment process). See the final CAIR boilermaker TSD for further discussion of the assumptions for this scenario.
3. CAIR Phase II Policy Case. This scenario examines boilermaker labor requirements for the second CAIR phase (2015 for both NO_x and SO₂), and is based on EIA assumptions for electricity demand and natural gas prices and UARG assumptions for boilermaker duty rates (see scenario 2, above).

The Agency analyzed the scenarios of CAIR SCR and/or FGD retrofits and coal switches that may increase sulfuric acid emissions sufficiently to trigger the NSR threshold, as discussed in the Supplemental Notice. For its analysis of boilermaker labor requirements for SO₃/H₂SO₄ controls, the Agency examined units in the CAIR_CAMR_CAVR IPM parsed files⁶ to determine which units are projected to install SCR and/or wet FGD during the two CAIR phases. In doing so, it was important to only include incremental retrofits, to prevent double-counting of retrofits that occur in 2010 but show up as retrofits in 2015 as well, and to prevent the inclusion of units that install retrofits before CAIR takes effect. From these units, EPA eliminated units 1) installing SCR but switching from high to low sulfur coal, 2) installing wet FGD but not switching from low to high sulfur coal, and 3) installing both SCR and wet FGD but not switching from low to high sulfur coal. As discussed in the Supplemental Notice, the Agency believes that the three aforementioned categories of retrofits would not increase SO₃/H₂SO₄ emissions sufficiently to trigger NSR. The remaining units were included in EPA's boilermaker labor analysis, assuming that such units would retrofit wet ESP to avoid exceeding the NSR threshold. From this analysis, the following amounts of wet ESP installations were estimated for the three CAIR scenarios described above:⁷

⁶ Parsed files refer to files that show unit-specific projections based on how model plants are projected to change in IPM. All relevant parsed files are in the CAIR docket (EPA-HQ-OAR-2003-0053).

⁷ The Agency estimated capacity of wet ESP retrofits based on the CAIR/CAMR/CAVR IPM modeling. For the Modified CAIR Phase I Policy Case, the Agency estimated an increased wet ESP retrofit capacity to take into account EIA assumptions for electricity demand and natural gas prices. Capacity of NO_x and SCR retrofits used in this analysis are consistent with the retrofit capacities in the boilermaker labor analysis for the final CAIR (i.e., they are based on CAIR modeling that does not include the CAMR and CAVR requirements).

1. 41.66 GW of wet ESP retrofits required for CAIR Phase I Policy Case
2. 48.75 GW of wet ESP retrofits required for Modified CAIR Phase I Policy Case
3. 27.76 GW of wet ESP retrofits required for CAIR Phase II Policy Case

The boilermaker duty rate for installing wet ESP was determined to be 0.05 boilermaker year per MW of wet ESP retrofit. This was based on a comparison of the boilermaker labor-related scopes included in installing wet ESP, FGD, and SCR. The boilermaker labor requirements were estimated using the above amounts of wet ESP retrofits, boilermaker duty rate, and the boilermaker requirements associated with installing NO_x and SO₂ controls (as included in the original boilermaker analysis).

In EPA's original boilermaker analysis, the Agency included all states it anticipates will be regulated under CAIR, including those states regulated for ozone-season NO_x only and New Jersey and Delaware. The current boilermaker analysis includes the same group of states; however, this analysis is not perfectly comparable with the previous boilermaker analysis since the current analysis includes units that retrofit SO₃/H₂SO₄ mitigation controls as a result of the Clean Air Visibility Rule, and thus overstates the cost and boilermaker labor required for wet ESP. For the sake of consistency though, the same number of FGD and SCR retrofits was assumed in this boilermaker analysis as in the original boilermaker analysis. These values are shown in the "Boilermaker Calculations" spreadsheet.

Based on the current boilermaker labor analysis, EPA determined that adequate boilermaker labor would be available for all three CAIR scenarios evaluated, even considering additional boilermakers that may be needed to install SO₃/H₂SO₄ controls. The results of this analysis are summarized below:

1. For CAIR Phase I Policy Case, the required labor for installing all NO_x, SO₂, and SO₃/H₂SO₄ controls is 12,300 boilermaker years, compared with the available labor of 24,000 boilermaker years. This represents a high contingency factor in the available labor of 95 percent.
2. For the Modified CAIR Phase I Policy case, the required labor for installing all NO_x, SO₂, and SO₃/H₂SO₄ controls is 24,300 boilermaker years, compared with the available labor of 25,100 boilermaker years. This represents a contingency factor in the available labor of 4 percent. This contingency factor falls short of the 15 percent factor in the boilermaker labor analysis conducted for the final CAIR. However, it should be noted that this case is based on using conservative boilermaker duty rates for SCR and FGD retrofits that were proposed by UARG, a commenter on the original CAIR proposal. The EPA performed boilermaker analysis on this scenario to verify adequacy of the available boilermaker labor force for CAIR, using the UARG-proposed boilermaker duty rates, which were substantially higher than those recommended by

Technical Support Document: Impact on CAIR Analyses of D.C. Circuit Decision in New York v. EPA

EPA and which were judged to be the outer bounds of the boilermaker requirements for installing SCR and FGD retrofits. Additionally, this scenario is based on EIA assumptions for electricity demand and natural gas prices, which are higher than the assumptions that the Agency believes are most appropriate for these parameters. For these reasons, the boilermaker availability contingency factor of 4 percent for this highly conservative case is considered adequate.

3. For CAIR Phase II Policy Case, the required labor for installing all NO_x, SO₂, and SO₃/H₂SO₄ controls is 18,000 boilermaker years, compared with the available labor of 24,400 boilermaker years. This represents a contingency factor in the available labor of 36 percent, which is considered adequate.

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