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Consulting to the Air Pollution Control Industry

History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations

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Contents

List of Figures

Tables

I. Executive Summary

This report explores the history of flexible compliance with technology-based and science-based stationary source air pollution regulations. The report identifies strategies that in some cases were not contemplated by the U.S. Environmental Protection Agency (EPA) when promulgating the rules or that differed from air pollution control technologies EPA considered when developing the rules (for example, innovative control techniques, shifting production to less-polluting facilities, or lower-polluting fuels). The report identifies the EPA's basis for each rule examined, how the rules allowed for flexible compliance choices, and specific compliance choices by covered entities, some of which were not envisioned when the rule was promulgated but were implemented as lower-cost solutions. This report demonstrates that compliance flexibility is a feature of the Clean Air Act (CAA)—not evidence that the EPA inappropriately set a standard—and that stakeholders could reasonably expect a similar range of compliance strategies to emerge under EPA's proposed standards of performance and emission guidelines for greenhouse gases (GHGs) emitted by electric generating units (EGUs).[1] Examining prior EPA rules and how industry responded, in several cases the electric generating industry utilized methods that might not have been envisioned when forecasting the cost of complying with the rule. This is because EPA incorporates flexibility provisions that allow states and industry to find ways to meet the objectives of the rule at a lower cost than originally envisioned by EPA.

EPA rules permit flexibility through a number of means that are available based upon the statutory requirements underlying the rule. This flexibility is generally achieved through the following:

- The rules tend to emphasize emission reduction requirements or emission rates, rather than specific technologies. Although an emission reduction or emission rate may be justified on the basis of available technology, by requiring sources to achieve an emission reduction or emission rate, facility owners can select a technology or combination of technologies that best suits their circumstances.

- Some of the specific approaches used by EPA to provide flexibility include:
    - Use of performance standards rather than technology mandates
    - Use of facility-wide or system-wide averaging
    - Emissions trading, and/or total mass emissions levels
    - State Implementation Plans (SIPs) that give states flexibility to make their own plans that meet the stringency of the rule
    - Emissions limits that are averaged over periods of time

[1] 88 Fed. Reg. 33,240 (May 23, 2023).

This report also provides case studies that demonstrate how many of these flexibility provisions were incorporated into EPA programs, including the following:

- EPA programs that utilized emissions rates or emission reduction standards rather than specifying a particular technology. These have included criteria pollutant programs, such as the New Source Performance Standards, Best Available Control Technology (BACT), and reasonably available control technology (RACT) permit requirements for nitrogen oxides (NOx), as well as hazardous air pollutant programs, such as the Mercury and Air Toxics Standards (MATS). As shown, each of these programs incorporated emissions limits that allowed facility owners to take into account their particular circumstances when selecting a technology to meet the requirements of the rule, which also incentivized technology innovation that saw technologies utilized that were not envisioned when EPA developed the rule. For example, through technical innovation: 1) SO_2 emission rates for new sources progressively declined over time; 2) although NOx RACT was based upon combustion controls, several facilities complied with NOx RACT requirements using selective non-catalytic reduction (SNCR), a post-combustion control; and 3) the MATS rule was complied with at a much lower cost than EPA had anticipated.

- EPA programs that incorporated emissions trading and emissions averaging, such as the Title IV Acid Rain Program and the Ozone Transport Commission Memo of Understanding (OTC MOU), NOx SIP Call, Clean Air Interstate Rule (CAIR), and Cross State Air Pollution Rule (CSAPR). As demonstrated here, facility owners deployed a range of technologies to comply with these programs – with some facilities controlling to much greater degrees than others. In addition, this approach motivated significant technological development, such as improving emissions performance of scrubbed units, utilization of cleaner fuels (low sulfur fuels and natural gas, for example), and utilization of lower cost technologies, such as SNCR.

- State programs delineated in SIPs that were developed to comply with one or more EPA programs. These included the Illinois Multi-Pollutant Standards (MPS), North Carolina's Clean Smokestacks Act (CSA), Colorado's Clean Air Clean Jobs Act (CACJA), and the Maryland Healthy Air Act (MDHAA). Each of these state programs utilized some features and technical approaches that were described above. For example, the MPS established fleetwide emissions averages for NOx and SO_2, the CSA and MDHAA established statewide emissions budgets, and the CACJA encouraged transition to lower emitting energy sources.

II. Background

Many sections of the CAA incorporate compliance flexibility. For example, Title I, Part C, of the CAA includes the program for Prevention of Significant Deterioration (PSD) of air quality, Section 110 and Title I, Part D, of the CAA include requirements for SIPs for complying with ambient air quality standards, Section 111 provides for performance standards to reduce stationary sources' emissions of pollutants not covered by other section of the CAA, Title IV comprises the acid rain provisions of the CAA, and Section 112 includes requirements for limiting emissions of hazardous air pollutants. Examples will be provided for how EPA incorporated compliance flexibility into each of these programs pursuant to Congress's direction in the CAA.

One of the purposes of compliance flexibility is to promote technical innovation. This goal is perhaps best illustrated in the history of regulation under CAA Section 111, where EPA has previously set standards designed, in part, to encourage technological innovation.[2] The agency has recently reaffirmed in its proposed standards and guidelines for greenhouse gas emissions from fossil-fueled electric generators that technical innovation is an important purpose of CAA Section 111:

> *"The D.C. Circuit has long held that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the 'best system of emission reduction.'"*[3]

> *"The legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (1) The development of technology that may be treated as the 'best system of emission reduction . . . adequately demonstrated' under CAA section 111(a)(1); (2) the expanded use of the best demonstrated technology; and (3) the development of emerging technology."*[4]

The following sections explain how EPA has exercised its authority under the CAA to provide compliance flexibilities that have in many cases led to improved emissions controls.

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[2] Those standards were upheld by the D.C. Circuit Court of Appeals. *See Sierra Club v. Costle*, 657 F.2d 298, 346 (D.C. Cir. 1981) ("Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance.").

[3] 88 Fed. Reg. at 33,275.

[4] *Id.*

III. Aspects of CAA rules or statutory provisions that provide flexibility

A. Emphasis on emissions reductions or emissions limits, rather than specification of a particular technology

Depending upon the pollutant and source category, EPA may require compliance with an emission rate or limit or may require a minimum level of emission reduction. Which approach (emission limit or level of emission reduction) is typically determined by the technical characteristics of the source and the technologies or methods available for controlling the source. While EPA will typically consider technologies that are available for complying with an emission limit or level of emission reduction when formulating emission limits or levels of emission reduction, rules and statutes do not dictate how the affected sources must comply with the emission limit or level of emission reduction. EPA usually needs to consider technologies to assess if an emission limit or level of emission reduction is feasible. But, owners of controlled sources are normally given the opportunity to determine the approach for compliance that is best for their circumstances. This report will provide examples of where technology-based or science-based emission limits were established and how industry responded with innovative approaches for compliance.

B. Flexibility in approaches for compliance and setting standards

There are a number of approaches under the CAA that provide opportunities for compliance flexibility. Some of these approaches were facilitated by technology developments, most notably development of Continuous Emission Monitoring Systems (CEMS), which are systems that can continuously monitor the pollutant emissions associated with an emissions source, and calculate emissions rates, total mass emissions, or other parameters that characterize the emissions of the emissions source. CEMS have facilitated many of the approaches discussed below, such as trading, total mass emission limits, averaging across multiple units, and averaging emissions across time.

1. Use of performance standards rather than requirements to use a specific technology

Following statutory instructions, EPA normally establishes requirements for emissions limits or emissions reductions based on technologies or practices, rather than requiring a specific technology. Although technical options are often evaluated during rulemaking to determine what approaches are available to reduce emissions, requirements generally will not dictate a specific technology. The advantage of this approach is that facility owners have the flexibility to select approaches that best suit their situations. A facility owner may decide to make a change in fuel or use a different technology than might be used by another facility in a different situation. The other advantage is that use of emissions performance standards motivates technology suppliers to develop improved means of mitigating emissions that may offer cost reductions or other benefits.

2. Facility-wide or system-wide averaging

In some cases there are multiple emission sources at a single facility or within a system. When compliance with a standard allows for a facility or system average emission rate, it is possible to over-control one or more emission units and under-control other emission units. The advantage this provides is the ability to over-control those emission sources that are easier (or more cost-effective) to control and under-control those emission sources that are more difficult (or less cost-effective) to control.

3. Emissions trading, and/or total mass emission limits

Emissions trading is another flexibility mechanism that is permitted under several sections of the CAA. The design of the trading program will differ based upon the specific pollutant and section of the CAA. Trading may be in the form of a total mass emission limit, such as under the Title IV (Acid Rain) SO_2 requirements of the 1990 Clean Air Act Amendments (CAAA). Trading might also be used in the form of achieving an emission rate (i.e., lb/MWh) within a jurisdiction.

In addition to the Title IV program, trading was also deployed in the 1998 NOx SIP Call, the 2005 Clean Air Interstate Rule (CAIR), and the 2011 Cross-State Air Pollution Rule (CSAPR). In addition to these EPA programs, some state programs used trading or averaging across the state or across systems within their jurisdictions – in some cases using total mass emission limits or in others using emission rate limits. Also, as will be described in some case studies, some state programs that incorporated trading or average emission rates across a jurisdiction or system also could be used to address the Regional Haze Rule (RHR), which could establish unit-specific emission limits for Best Available Retrofit Technology (BART)-affected units. All of these were consistent with the provisions of the CAA.

4. State plans, including SIPs

Many CAA provisions allow states the opportunity to develop and submit a plan to demonstrate how they will comply with EPA standards. In the context of meeting NAAQS, "[a] State Implementation Plan (SIP) is a collection of regulations and documents used by a state, territory, or local air district to implement, maintain, and enforce the National Ambient Air Quality Standards, or NAAQS, and to fulfill other requirements of the Clean Air Act."[5] Requirements for SIPs are addressed in Section 110 and Sections 171 through 193. US EPA establishes the NAAQS and states detail how those NAAQS will be met within the state. Following Congress's instructions in the CAA, the RHR also provided for its requirements to be met through SIPs.[6] SIPs give states the flexibility to make decisions about how national standards will be met within the

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[5] https://www.epa.gov/air-quality-implementation-plans/basic-information-about-air-quality-sips
[6] 64 Fed. Reg. 35,714, 35,722 (July 1, 1999).

state. In some cases these will be source-specific limits[7] and in other cases states may establish other programs that achieve the same or greater stringency than would be achieved by regulation on an individual unit basis. An example of when a source-specific limit might be needed is when nonattainment of the SO_2 NAAQS might only be addressed with a requirement on the facility that most impacts the local, ambient SO_2 concentrations rather than a trading program that might not address a local, SO_2 nonattainment situation. But, even in such a case where a facility-specific limit was needed, the facility would have the flexibility to meet an emission standard through means that might include changing fuels, adding controls, or limiting operations, and that flexibility might be incorporated into the SIP.

Depending upon the EPA program, some features are permitted in state plans and others are not. For example, trading or system averages might not be permissible for Section 111 programs that address locally harmful pollutants, while trading or system averages might be permitted for other state programs implementing EPA requirements. This report will provide examples of states that have implemented their own rules or statutes to meet EPA requirements. These state rules or statutes often incorporated one or more of the other means of compliance described (emission rates averaged over a period of time, system or facility average emissions rates, or trading under mass emission limits).

5. Emissions limits that are averaged over periods of time determined for the specific pollutant or need

When CEMS are installed, emission rates may be established over specific averaging periods that are determined to be consistent with the pollutant of concern, its short-term or long-term impacts, and the ability to control that pollutant. These averaging periods may also be determined by states in their SIPs and associated regulations to meet the specific needs of the relevant EPA requirement.

IV. Case studies

Following instructions in the CAA, EPA will generally issue performance standards without requiring implementation of a specific technology. Although emission standards may be developed based upon an understanding that one or more technologies are available to meet the standard, facility owners are free to meet the standard using other means. Trading programs and similar flexibility mechanisms (fleetwide averages, state averages, etc.) can enable compliance through a range of approaches, including the installation of technologies with different levels of efficiency and costs for different units, rather than the same technology on all units. Also, trading or averaging emissions over more than one unit creates an incentive for increasing the emissions

[7] As will be discussed later in this report, the State of New Hampshire established source-specific limits for the Public Service Company of New Hampshire for 1995 NOx RACT. Also, several SIPs for EPA's RHR determined source-specific emission rates through a BART analysis process.

capture efficiency for technologies, such as scrubbers and selective catalytic reduction controls (SCRs). For each of these approaches, this report discusses how flexibility stimulated technology development, which had additional beneficial effects.

A. Use of performance standards rather than requirement of a specific technology

The CAA most often allows sources to comply with emission performance standards, which will require compliance with an emission rate or a degree of emission reduction (often represented as a percentage of emission reduction). While these emission standards are frequently determined based upon the capabilities of technologies to achieve emission levels, the facility owner is given a significant degree of flexibility in how they achieve these emission levels. Examples are given for both criteria pollutants and hazardous air pollutants (HAPs) because these pollutants have different characteristics and therefore need to be treated differently. For example, NOx contributes to ground-level ozone, NO_2 and fine particulate matter (PM), all of which are criteria pollutants subject to NAAQS. The criteria pollutants ozone, SO_2, NO_2, and PM all contribute to various respiratory illnesses and may contribute to other health conditions.[8] The effects may be realized even in short exposure, depending upon the concentrations. For that reason, NAAQS generally have a concentration limit for a specified exposure time (for example, one-hour or eight-hour exposure).[9] HAPs are substances that cause or are suspected of causing cancer, birth defects, or other serious harms.[10] HAPs can cause cumulative damage over time and can therefore be harmful even at low exposure levels if over a longer period of time. For example, mercury is a neurotoxin that can contribute to diminished mental ability.[11]

1. Criteria pollutant and National Ambient Air Quality Standards (NAAQS) provisions

"Criteria air pollutants are air pollutants for which acceptable levels of exposure can be determined and for which an ambient air quality standard has been set. Examples include: ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, and [particulate matter] PM10 and PM2.5."[12] NAAQS are often set for different exposure periods, such as 8-hour or 1-hour standards. NAAQS are periodically updated based upon a comprehensive process that includes an Integrated Science Assessment, a Risk/Exposure Assessment and a Policy Assessment.[13] States have the responsibility to develop SIPs that will enable them to achieve the NAAQS, and the SIPs will include limitations on source emissions that contribute to criteria pollution levels.

[8] https://www.epa.gov/isa
[9] https://www.epa.gov/criteria-air-pollutants/naaqs-table
[10] 42 U.S.C. § 7412(b)(2).
[11] 88 Fed. Reg. 13,956, 13,969 (Mar. 6, 2023).
[12] https://ww2.arb.ca.gov/our-work/programs/criteria-air-pollutants
[13] https://www.epa.gov/criteria-air-pollutants/process-reviewing-national-ambient-air-quality-standards

Preserving air quality is achieved by maintaining concentrations of criteria pollutants under the NAAQS. Emissions impacting air quality from new and existing sources will increase the concentration of criteria pollutants in nearby and downwind areas. To address new and existing sources that impact air quality, the CAA has provisions that limit emissions of criteria pollutants, such as:

1. New Source Performance Standards (NSPS) and New Source Review, including Prevention of Significant Deterioration through the application of Best Available Control Technology (BACT), and
2. Attainment of air quality standards through reduction of emissions from existing facilities, through, for example, application of Reasonably Available Control Technology (RACT).

a. New Source Performance Standards (NSPS) and BACT

Section 111 of the CAA requires EPA to establish standards of performance for new sources. The 1977 amendments to the CAA established changes to new source standards for emissions from coal-fired EGUs that were intended to meet certain goals for all steam EGUs firing in excess of 250 MMBtu/hr and where construction commenced after September 18, 1978. Among these goals were the following:[14]

- "maximize the potential for long-term industrial growth by reducing emissions as much as practicable."[15] In effect, this feature encouraged lower emission rates so that future industrial growth isn't limited by air quality standards.
- For new plants, "to the extent practical force the installation of all the control technology that will ever be necessary on new plants at the time of construction . . . thereby minimizing the need for retrofit in the future when air quality standards begin to set limits to growth."[16] This is consistent with the prior goal of reducing emissions as much as practicable, essentially to preserve the air quality increment, and is consistent with BACT requirements, which were *the best controls that could be installed at the time* of construction or modification with consideration of energy, environmental and economic factors. Use of BACT at any point in time does not obviate the need to meet other obligations of the CAA, such as considering contemporary or future air quality impacts on downwind regions, potentially under revised NAAQS.
- "[B]e stringent in order to force the development of improved technology."[17] The goal was to promote technical innovation that would further improve air quality.

[14] 44 Fed. Reg. 33,580, 33581-82 (June 11, 1979).
[15] *Id.*
[16] *Id.*
[17] *Id.*

Technology suppliers would be motivated to improve their technology so that their technology would be selected rather than their competitors' technologies.

- In developing the 1977 amendments to the CAA, Congress was critical of the then current SO_2 NSPS for coal plants and especially the fact that it could be met with the use of low sulfur coal without a scrubber.[18] The SO_2 NSPS would be changed to:[19]
    - '*New source performance standards for fossil-fuel-fired sources (e.g., power plants) must require a "percentage reduction" in emissions, compared to the emissions that would result from burning untreated fuels.'* Specific to SO_2 emissions, this meant that some degree of post-combustion control was envisioned for NSPS, but the type of scrubber was up to the owner or operator so long as it met requirements for emission rates and percentage emission reductions.
    - This provision, while still permitting some choice as to technology, illustrates that Congress knew how to prescribe a certain means of technology-based requirement – but that, in general, it did not do so in the CAA. Congress removed the percentage-reduction requirement in the 1990 CAA Amendments.

EPA established standards for all coal-fired EGUs where construction commenced after September 18, 1978. New source standards must be based upon consideration of available technologies. But, the NSPS did not dictate the technology to be used at the facility. For example, the SO_2 NSPS established in 1979 was:

> *"based on the performance of a properly designed, installed, operated and maintained FGD system. Although the standards are based on lime and limestone FGD systems, other commercially available FGD systems (e.g., Wellman-Lord, double alkali and magnesium oxide) are also capable of achieving the final standard. In addition, when specifying the form of the final standards, the Administrator considered the potential of dry SO_2 control systems . . ."*[20]

An NSPS for particulate matter (PM) of 0.03 lb/MMBtu, for example, could be achieved by either a baghouse or electrostatic precipitator (ESP). The NOx emission standard (expressed in terms of lb/MMBtu) varied by fuel or type of furnace and did not require a specific technology, but was based upon combustion controls.[21] The SO_2 limit outlet emission rate differed based upon outlet emission rate to allow for lower capture efficiencies for lower outlet emission rates as follows:

[18] *Id*. at 33,581.
[19] *Id.* at 33,582.
[20] *Id.* at 33,592.
[21] *Id.* at 33,591.

- 1.2 lb/MMBtu and 90% capture
- 70% capture when emissions were less than 0.60 lb/MMBtu

There are other requirements beyond NSPS that impact new sources as well. The 1977 CAA established specific numerical increments (maximum allowable increases in ambient concentration) and ceiling concentrations for ambient PM and SO_2 in the Prevention of Significant Deterioration (PSD) program in Part C of the CAA, and EPA would promulgate PSD provisions for NOx in 1988.[22] PSD is designed to:[23]

- protect public health and welfare;
- preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value;
- insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources; and
- assure that any decision to permit increased air pollution in any area already attaining the NAAQS is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decision making process.

Per the PSD provisions of the CAA (Part C, or Sections 160-169) all major new sources located in attainment areas must adopt the best available control technology (BACT).

Pursuant to 42 U.S.C. § 7479(3) (Section 169 of the CAA), BACT is defined as:

"an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under [the Clean Air Act] emitted from or which results from any major emitting facility, which [EPA], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Section 7411 or 7412 of this title."

Therefore, the emission standard resulting from BACT is the "maximum degree of reduction" taking into account energy, environmental and economic impacts determined in a case-by-case manner for each facility, and it has to be at least as stringent as the NSPS. In the sense that it is a case-by-case analysis, BACT is not a one size fits all standard. And, as previously

[22] https://www.epa.gov/sites/default/files/2015-12/documents/20050929fs.pdf
[23] https://www.epa.gov/nsr/prevention-significant-deterioration-basic-information

noted, a goal of the program was to reduce emissions as much as practicable, and to promote development of improved technology. Accordingly, in time the emission limits should be expected to decline. In practice, emission limits on affected units in attainment areas would be governed by BACT because the NSPS is the minimum threshold for stringency for BACT, and a BACT analysis should generally result in a more stringent emission limit than NSPS. New sources located in nonattainment areas must meet the lowest achievable emission rate (LAER).[24]

To demonstrate how these standards (particularly BACT) promote innovation across technologies, data from US EPA's RACT/BACT/LAER Clearinghouse (RBLC) was examined for coal-fired EGUs with 90 new source permits issued to coal-fired EGU boilers between 1978 and 2011. Each of these facilities, except perhaps for one,[25] was subject to BACT, and therefore had to install technology to achieve the maximum degree of reduction on a case-by-case basis taking into account energy, environmental, and economic factors. Figure 1 represents new source permitted SO_2 emission limits in lb/MMBtu for pulverized coal units versus the year that the permit was issued. As shown, permitted emissions levels have generally declined over time, consistent with the goal of improving technology through standard-setting and consistent with the impact of BACT requiring the maximum degree of reduction taking into account energy, environmental and economic effects.[26] The figure also enables comparison of dry or wet FGD. Within each of those two general technology categories, there are multiple types of processes. The trend of decreasing emission limits apparent in the figure is consistent for both general types of technology and demonstrates that technology advanced over these decades.[27]

Examining this figure, there is a clear trend that emission limits determined through the BACT process declined over time. New Source Standards and BACT emission limits permit facilities to choose the technology that meets their needs while satisfying the requirements of the regulations. This feature of the regulations contributed to the continual improvement in technology over time as technology suppliers were motivated to innovate so that their technology would be chosen by facility owners and, in turn, air permitting authorities.

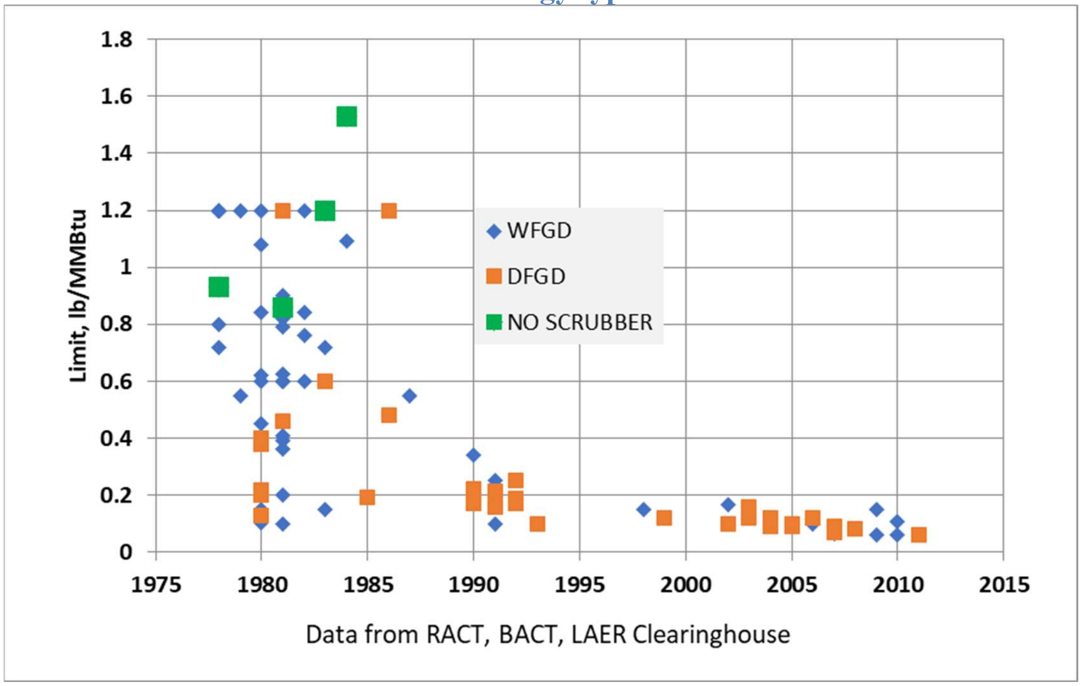
[24] 44 Fed. Reg. at 33,612. LAER is more stringent than BACT and is required in nonattainment areas. LAER "*reflects: (A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or (B) The most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.*"

[25] See discussion in Appendix A.

[26] That goal is stated at 44 Fed. Reg. 33,581-82.

[27] There are some apparent inconsistencies during the early years of this program, noticeably four units that were not permitted with a scrubber and several units with emission limits of 1.2 lb/MMBtu with a scrubber. A more detailed discussion is provided in Appendix A.

Figure 1. New source SO_2 emission limits for pulverized coal EGU boilers, by control technology type[28]



b. NOx RACT

RACT stands for Reasonably Available Control Technology. RACT is determined through "implementation of the lowest emission limitation that an emission source is capable of meeting by the application of a control technology that is reasonably available, considering technological and economic feasibility."[29]

The CAA requires RACT to be implemented in nonattainment areas:

"The Clean Air Act amendments of 1990 introduced the requirement for existing major stationary sources of NOx in nonattainment areas to install and operate NOx RACT. Specifically, section 182(b)(2) of the CAA requires States to adopt RACT for all major sources of volatile organic compounds (VOC) in ozone nonattainment areas; and, section 182(f) requires the RACT provisions for major stationary sources of oxides of nitrogen."[30]

In 1992, EPA determined that presumptive NOx RACT for coal-fired EGUs would be the following emission levels on a 30-day rolling average and could be applied to boilers on an area-wide basis:[31]

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[28] Data from US EPA RACT/BACT/LAER Clearinghouse, at: https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en. In some cases the requirement was a percent reduction in addition to the stated limit, and would actually result in a lower emission level in practice.

[29] https://deq.utah.gov/air-quality/reasonably-available-control-technology-ract-process-ozone-sip

[30] https://www3.epa.gov/region1/airquality/noxract.html

[31] 57 Fed. Reg. 55,620, 55,626 (Nov. 25, 1992).

- 0.45 lb/MMBtu for tangentially-fired furnaces
- 0.50 lb/MMBtu for dry-bottom wall-fired (other than cell burner)

States could adopt NOx RACT rates other than these presumptive rates, but EPA expected states, "to the extent practicable, to demonstrate that the variety of emissions control adopted are consistent with the most effective level of combustion modification reasonably available for its individual affected sources."[32] Therefore NOx RACT was to be based upon combustion control technology.

The 1990 CAAA (Section 184) established the Ozone Transport Region (OTR). The OTR is a region in the Northeast United States where it was determined that ozone transport was so pervasive that it would be treated as a single nonattainment area. Per the requirements of the CAA, in the OTR, RACT would need to be deployed by the beginning of the 1995 ozone season (May through September). The following examples demonstrate that this requirement, which was presumed to be based upon low NOx combustion controls, could be met through the use of other technologies:

New England Power Salem Power Plant[33]

In 1993, New England Power (NEP) conducted the first ever commercial demonstration of an SNCR system on a coal-fired power plant in the United States. The plant installed SNCR for 1995 NOx RACT compliance on its three coal units: 88 MW Unit 1, 84 MW Unit 2, and 155 MW Unit 3 to comply with an emission rate of 0.30 lb/MMBtu. NEP utilized a combination of combustion controls and SNCR to achieve these rates because combustion controls alone were not adequate to achieve these emission rates, and a combination of combustion controls with SNCR resulted in lower reagent consumption rates than using SNCR alone.

Montaup Electric[34]

The Commonwealth of Massachusetts established NOx RACT for tangentially-fired EGUs to be the following on a 24-hour average:

- 0.38 lb/MMBtu when firing coal
- 0.25 lb/MMBtu when firing fuel oil

Montaup Electric's Somerset generation station boiler #8 was a 112 MW tangentially-fired boiler that started up on oil and normally operated on coal. It sometimes co-fired oil and coal at

[32] *Id.* Also in 1996 EPA would promulgate presumptive NOx RACT limits for wet-bottom and cyclone units at 61 Fed. Reg. 67,112 (Dec. 19, 1996).

1995 NH RACT was defined in: https://www.epa.gov/system/files/documents/2021-12/nh-14.pdf

[33] Andover Technology Partners, for Northeast States for Coordinated Air Use Management, *Status Report on NOx: Control Technologies and Cost Effectiveness for Utility Boilers*, June 1998, pp. 128-130.

[34] Staudt, J., et al., "COMMERCIAL APPLICATION OF UREA SNCR FOR NOx RACT COMPLIANCE ON A 112 MWe PULVERIZED COAL BOILER", EPRI/EPA 1995 Joint Symposium on Stationary Combustion NOx Control, Kansas City, Missouri, May 16-19, 1995.

part load. To comply with Massachusetts's NOx RACT regulation, Montaup Electric considered Low NOx Burners, Gas Reburn, SNCR and SCR for control of NOx.[35] Montaup Electric ultimately settled on SNCR, a post-combustion technology that operates by injecting urea into the furnace to reduce NOx emissions. Therefore, although the presumptive emission limits envisioned by EPA were based upon combustion controls, in this case the facility owner chose to install post-combustion controls.

Atlantic Electric, B.L. England Station[36]

Atlantic Electric operated B.L. England station in Beesley's Point, NJ, near Atlantic City, NJ. Three units were on the site, two 160 MW units and one 130 MW unit. In 1995 the State of New Jersey RACT regulations required the three units to reduce NOx to the controlled NOx levels of 0.85 lb/MMBtu for the cyclone-fired unit 1 (130 MW) and unit 2 (160 MW). Unit 3 was tangentially fired and would need to control to 0.20 lb/MMBtu. Units 1 and 2 had fewer options for combustion control and therefore selected SNCR (which is less costly than SCR), while unit 3 would be equipped with combustion modifications and SNCR (rather than more expensive SCR controls).

PSE&G Mercer Generating Station[37]

Mercer Generating Station had two Foster Wheeler continuous slagging, twin-furnace steam generating units that operated on dispatch in a load-following mode. Units 1 & 2 were identical at 321 MW net each. The Mercer Generating Station was subject to NOx reductions due to the New Jersey RACT regulations. In anticipation of pending, necessary reductions, in 1993 PSE&G undertook a demonstration program to evaluate NOx reduction technologies, including urea-based SNCR (NOxOUT) and gas cofiring. The RACT guidelines, which were passed after the demonstration program was completed, required PSE&G to comply with a system-wide 24-hour average during the ozone season. Since PSE&G operated two large coal plants (Mercer and Hudson Plants) and several other oil and gas plants, PSE&G had a number of options for control. SCR was also an option for control on the Mercer station, and PSE&G did evaluate this technology in combination with SNCR in a demonstration program on one of the eight exhaust ducts for the two units,[38] but did not install it for RACT compliance due to the higher cost of this approach.

Public Service Company of New Hampshire (PSNH) Merrimack Units 1 & 2[39]

PSNH Merrimack #1 was a 120 MWg wet bottom, bituminous coal fired cyclone boiler. It was a base-loaded unit with uncontrolled NOx emissions of 1.34 lb/MMBtu. It was subject to 1995 NOx RACT and subsequent additional emission reductions. The State of New Hampshire

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[35] Andover Technology Partners, for Northeast States for Coordinated Air Use Management, *Status Report on NOx: Control Technologies and Cost Effectiveness for Utility Boilers*, June 1998, p. 132.
[36] *Id.* at 134.
[37] *Id.* at 142-143.
[38] *Id.* at 157-160.
[39] *Id.* at 144.

determined that 1995 NOx RACT for PSNH would be a maximum average NOx emission rate for a 24-hour calendar day of 1.22 lb/MMBtu with a daily maximum NOx emission of 18.1 tons per day. PSNH installed ammonia-based SNCR to meet the NOx RACT requirement.

PSNH Merrimack #2 was a 333 MWg wet bottom, bituminous coal-fired cyclone boiler. It was a base-loaded unit with uncontrolled NOx emissions of 2.66 lb/MMBtu. It was subject to 1995 NOx RACT and subsequent additional emission-reduction requirements. The State of New Hampshire determined that 1995 NOx RACT for PSNH Merrimack #2 would be a maximum average NOx emission rate for a 24-hour calendar day of 1.4 lb/MMBtu with a daily maximum NOx emission of 35.4 tons per day, which is approximately equivalent to 0.85 lb/MMBtu at full load for 24 hours. Hence, if continuous, 24-hour operation at full load was desired, a NOx reduction system capable of providing 68% reduction at full load was necessary. Additional reductions would be required in 1999 to reduce total NOx emissions to a maximum of 15.4 tons per day, which is equivalent to less than 0.40 lb/MMBtu at full load or an 85% reduction from the original uncontrolled peak daily baseline.

After initially considering SNCR, PSNH determined that SCR would be the technology of choice because it would provide reductions sufficient for both 1995 RACT and future NOx reduction requirements. This project was the first SCR retrofit on a coal-fired boiler in the United States. In the years since, SCR—a compliance option enabled by New Hampshire's rate-based NOx RACT—has become a state-of-the-art, industry-standard control technology that underlies requirements for large coal-fired EGUs in the 2023 Good Neighbor Plan to reduce cross-state ozone pollution, as required by CAA section 110.

General Public Utilities (GPU) Generating Seward Station[40]

Seward Station in 1995 was equipped with a 147 MW tangentially-fired coal boiler that fired 1.5% sulfur coal. Although Pennsylvania's NOx RACT was based upon combustion controls, GPU determined that SNCR would be a preferable technology because they expected to repower the unit with a circulating fluid bed boiler in the near term and the alternative of combustion controls had a higher capital cost than SNCR. The outlet emission rate limit was 0.45 lb/MMBtu, consistent with EPA's 1992 presumptive RACT.

2. Section 112 and the Mercury and Air Toxics Standards (MATS)

Air toxics (also known as hazardous air pollutants, or HAPs) are regulated under Section 112 of the CAA. This section of the CAA has different requirements than those for criteria pollutants because the pollutants regulated under this section of the CAA "are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects

[40] *Id.* at 140-141.

or birth defects, or adverse environmental effects."[41] In Section 112(b), Congress has specified a list of HAPs to be regulated by EPA and required EPA to add to that list, as appropriate.[42]

Congress specified in Section 112(d)(2) of the 1990 CAA Amendments that the EPA shall establish standards that require:

> *"the maximum degree of reduction in emissions of the [HAP] . . . (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies."*[43]

Recognizing that methods and practices for controlling emissions improve with time, Section 112(d)(6) further states that,

> *"[t]he Administrator shall review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years."*[44]

Furthermore, in the 1990 CAA Amendments Congress defined a new basis for standard-setting in Section 112(d)(3): Maximum Achievable Control Technology, or MACT:

> *"For major sources, Section 112 requires that EPA establish emission standards that require the maximum degree of reduction in emissions of hazardous air pollutants. These emission standards are commonly referred to as "maximum achievable control technology" or "MACT" standards."*[45]

Per Section 112(d) of the CAA, for source categories with at least 30 sources (such as coal-fired EGU boilers), the emission standards must be *no less stringent* than the average of what is being achieved by the 12% best performers.[46] EPA must establish a more stringent standard if it is justified by the factors in section 112(d)(2), quoted above.

Therefore, the emission limits under Section 112 are not necessarily based upon use of a specific technology. However, they can be no less stringent than levels determined by a statistical analysis of facilities that identifies the emission rates achieved by the best performing units. One

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[41] https://www.epa.gov/haps/what-are-hazardous-air-pollutants. "[A]dverse environmental effect" means "any significant and widespread adverse effect, which may reasonably be anticipated, to wildlife, aquatic life, or other natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental quality over broad areas." 42 U.S.C. § 7412(a)(7).

[42] *Id.* § 7412(b).

[43] *Id.* § 7412(d)(2).

[44] *Id.* § 7412(d)(6).

[45] https://www.epa.gov/laws-regulations/summary-clean-air-act

[46] 42 U.S.C. § 7412(d)(3)(A).

example of a rule employing this standard-setting methodology is the Mercury and Air Toxics Standards (MATS), which was established in 2011 to regulate HAP emissions from EGUs.

a. MATS

The MATS rule was finalized in late 2011 and required emissions reductions beginning April 2015.[47] For coal units, emission limits were established for mercury (Hg), non-Hg metals, and acid gases (especially, hydrogen chloride, or HCl).[48] Work practice standards were also included in the rule for organic HAPs.[49] EPA established Hg standards for low-rank coals (i.e., lignite) at 4.0 lb/TBtu and for non low-rank coals (primarily bituminous and subbituminous coals) at 1.2 lb/TBtu.[50] For non-Hg metal HAPs, compliance could be demonstrated by either:

- Demonstrating emissions of specific non-Hg metals were maintained under emission limits stated in the MATS rule, or
- Demonstrating emissions of filterable PM were maintained under an emissions limit of 0.030 lb/MMBtu.[51]

The alternative of complying with a filterable PM limit allowed facilities to comply with the use of control equipment and monitoring practices that might already be in place or that facility owners were already familiar with.

In the case of HCl, an emissions limit of 0.0020 lb/MMBtu was required, or alternatively, as a surrogate for HCl, maintaining SO_2 emissions below 0.20 lb/MMBtu for scrubbed units.[52] This was a flexibility provision that would allow facilities to demonstrate compliance with the HCl limit with equipment that was already installed (FGD and CEMS) for other reasons because EPA recognized that facilities with FGD controlling to a sufficiently low SO_2 emission rate were expected to be in compliance with the HCl limit.

EPA made forecasts of the control technologies to be used by EGUs to comply with the rule, and these are shown in Figure 2. "Base" means base-case, which is assuming that there was not a MATS regulation. "MATS" shows installations with MATS. The difference is EPA's projected impact of MATS. According to the Regulatory Impact Analysis issued with the final MATS rule: *"This analysis projects that by 2015, the final rule will drive the installation of an additional 20 GW of dry [flue gas desulfurization systems (FGD)] (dry scrubbers), 44 GW of [dry sorbent injection systems (DSI)], 99 GW of additional [activated carbon injection systems (ACI)], 102 GW of additional fabric filters [(FFs)], 63 GW of scrubber upgrades, and 34 GW of ESP*

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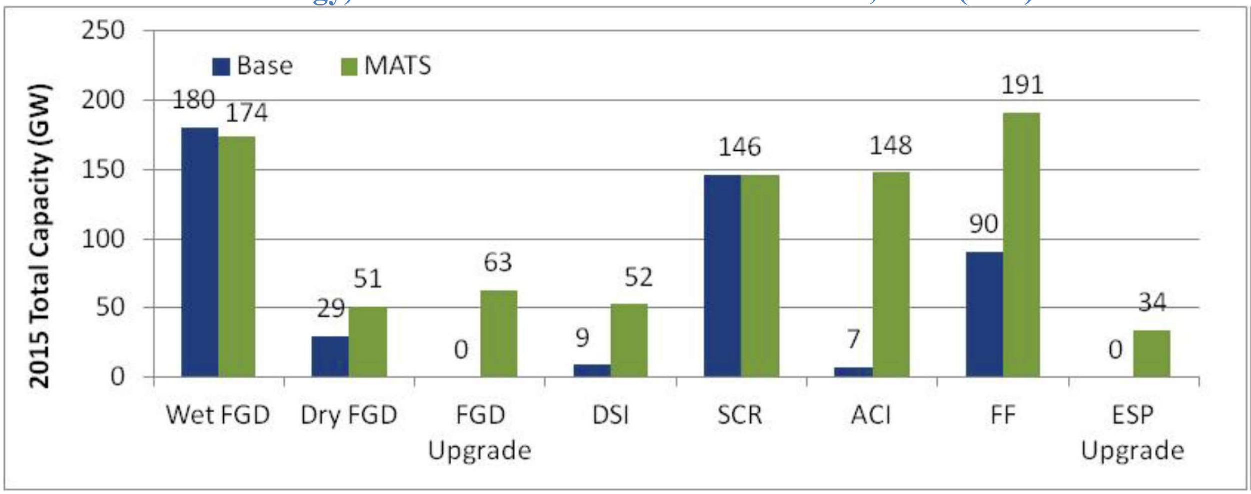
[47] *See* 77 Fed. Reg. 9304, 9407 (Feb. 16, 2012).
[48] *Id.* at 9367-69.
[49] *See id.*
[50] This limit was for each EGU. An emission limit of 1.0 lb/TBtu was required if facility-wide averaging was used. *See id.* at 9385.
[51] *Id.* at 9367-68 & Tbls. 3 & 5.
[52] *Id.*

upgrades. . . ."[53] These forecasts were for technology installations over and above those that were expected to occur for compliance with other rules, such as CAIR, CSAPR or the RHR. The annualized cost of all of the MATS compliance efforts was estimated by EPA to be $9.6 billion.[54]

Figure 2. Projected operating pollution control capacity on coal-fired capacity (by technology) under the Base Case and with MATS, 2015 (GW)[55]



MATS control costs were less than anticipated by EPA

As demonstrated by Staudt[56] in a declaration to the U.S. Court of Appeals for the D.C. Circuit, many of the forecasted control equipment retrofits did not occur. Overall, Staudt estimated that EPA overestimated the cost of the rule by about $7.2 billion per year.[57] In effect, the actual cost was about 25% of what EPA estimated it to be. For example, Figure 3 compares EPA's 2015 forecast of fabric filters and dry FGD for MATS, EPA's Base Case, and what was actually installed by 2015 for all EPA programs, inclusive of MATS. As shown, EPA's estimate, particularly for fabric filters (also known as baghouses), exceeded the actual fabric filter installations by about 100 GW.

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[53] Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, EPA-452/R-11-011, December 2011, pp. 3-14 to 3-15.

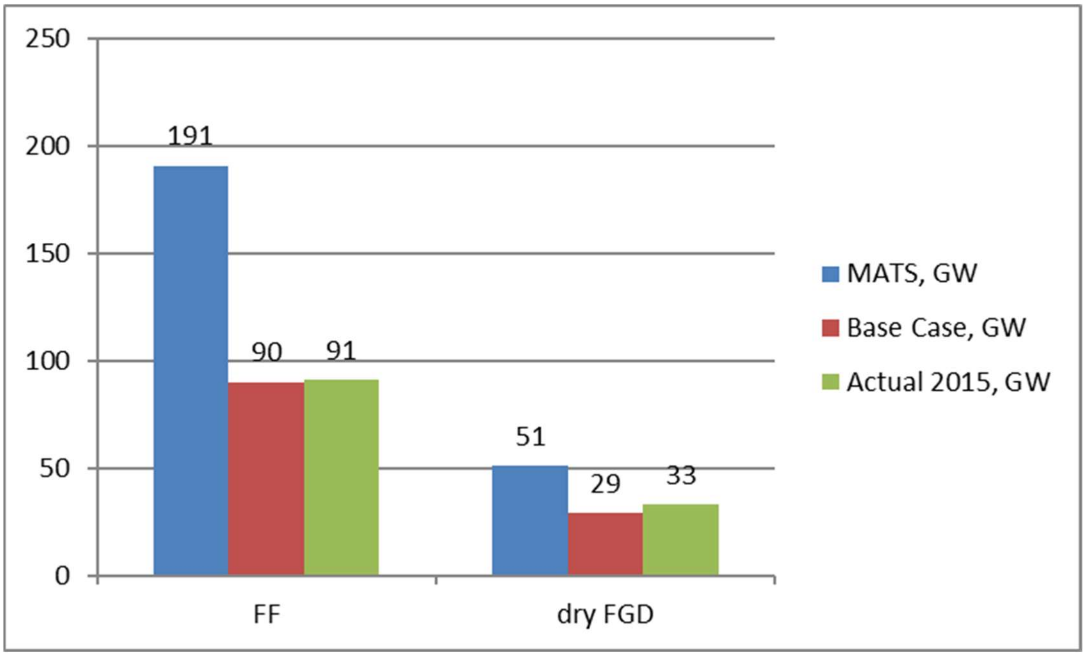
[54] *Id.* at 3-31.

[55] *Id.* at 3-15. Note: The difference between controlled capacity in the base case and under the MATS may not necessarily equal new retrofit construction, since controlled capacity above reflects incremental operation of dispatchable controls in 2015. Additionally, existing ACI installed on those units online before 2008 are not included in the base case to reflect removal of state mercury rules from IPM modeling. For these reasons, and due to rounding, numbers in the text below may not reflect the increments displayed in this figure. See IPM Documentation for more information on dispatchable controls.

[56] Staudt, J., Declaration before United States Court of Appeals for the District of Columbia Circuit, September 23, 2015; pdf page 17 of 30; available at: https://www.andovertechnology.com/wp-content/uploads/2020/09/Staudt-Declaration_2015_09_24_13_19_52-2.pdf.

[57] *Id.* at 6.

Figure 3. MATS and Base Case projections, and 2015 actual or planned installations of FF and dry FGD expected to be directly a result of MATS, GW[58]



There are a number of explanations for what happened:

- Owners of coal fired EGUs became more open to lower-cost means to comply with emissions standards than those EPA had projected in estimating the cost of the rule. For example, low-cost solutions that already were available - such as ESP rebuilds - that companies might have dismissed prior to the rule taking effect received more attention from owners of EGUs. ESP rebuilds during MATS implementation were determined to be very effective in reducing PM emissions, and more effective than EPA had anticipated.[59]
- Technology suppliers developed new, lower-cost technologies that achieved higher capture efficiencies than EPA had planned on when forecasting the cost of the MATS rule. Examples are more efficient activated carbons[60] and advances in dry

[58] *Id.* at 17.

[59] Staudt, J., Andover Technology Partners, *Assessment of Potential Revisions to the Mercury and Air Toxics Standards*, for Center for Applied Environmental Law and Policy (CAELP), June 15, 2023, pp. 16-17. available at: https://www.andovertechnology.com/wp-content/uploads/2023/06/C_23_CAELP_Final.pdf.

[60] Staudt, J., Andover Technology Partners, *Analysis of PM and Hg Emissions and Controls from Caol-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), August 19, 2021, pp. 48-51, available at: https://www.andovertechnology.com/wp-content/uploads/2021/08/PM-and-Hg-Controls_CAELP_20210819.pdf.

sorbent injection (DSI) technology.[61] Thanks to those developments, it was possible to achieve high Hg and HCl capture without the need for addition of a fabric filter.

- Because natural gas prices were persistently low, many smaller, less competitive coal units either retired or, if capacity was still necessary, converted to natural gas.[62]

Hg can be controlled through a number of means, including ACI, scrubbers, and chemical injection, all described in detail in ATP's 2021 report, and those technologies improved in response to the MATS rule.[63] This gave facilities a wide range of options to comply with the Hg limits of the MATS rule. PM can also be controlled in a number of ways, including upgrading of ESPs and with fabric filters (i.e., baghouses), as also described in detail in that document. In ATP's 2023 report,[64] by examining reported PM emissions data for ESP-equipped units prior to MATS and after MATS, ATP determined that ESP upgrades were being performed and offered lower emission rates than EPA had assumed were possible in its analysis for the April 2023 proposed MATS revisions. This confirmed that upgrade of existing ESPs was a much more viable approach for reducing PM emissions than previously believed. Acid gas controls also improved, so that DSI could be deployed for sufficient HCl capture without the need for a fabric filter.[65] Staudt's 2015 declaration also identified higher HCl capture efficiencies for DSI in combination with an ESP than assumed by EPA as contributing to EPA's overestimate of fabric filters. And, as stated, low natural gas prices played a role in giving uncompetitive coal units an option to convert to gas. All of these effects explain the over-estimate of fabric filters by EPA when forecasting the cost of the MATS rule.

Emissions averaging for a facility

MATS permitted emissions averaging at a facility. For example, if a power plant had multiple coal-fired EGUs, the emissions limit for a given pollutant, in lb/MMBtu or lb/TBtu, could be averaged over the facility.[66] An example of a facility that used emissions averaging to comply with MATS is Ameren Missouri's Labadie generating station. It is a facility with four, roughly 600 MW coal-fired boilers that are equipped with ESPs, and are unscrubbed and without SCR. The Notice of Compliance Status for Labadie, filed in July 2016, stated that Ameren was using

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[61] Staudt, J. Andover Technology Partners, *Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), April 5, 2022, pp. 38-41, https://www.andovertechnology.com/wp-content/uploads/2022/05/C_21_CAELP_3_04_05-js.pdf.

[62] United States Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, p. 13.

[63] Staudt, J., Andover Technology Partners, *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), August 19, 2021 (ATP 2021).

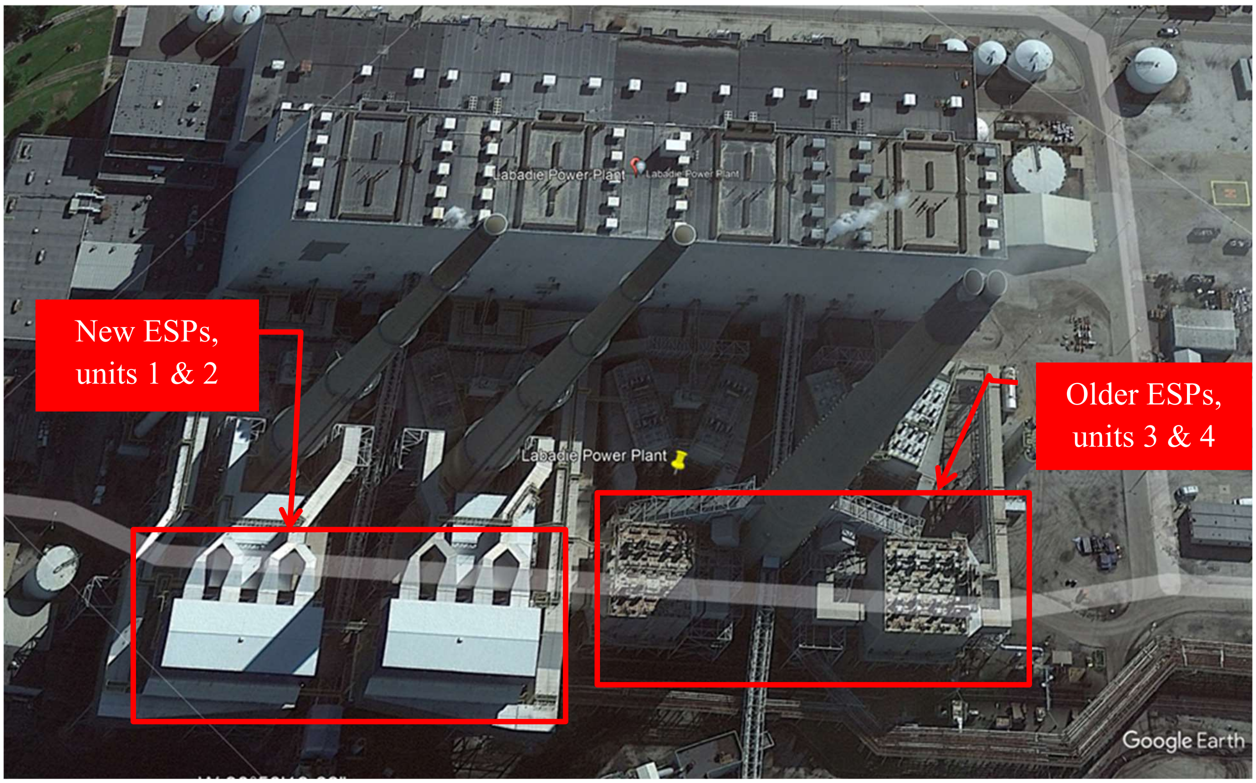
[64] Staudt, J., Andover Technology Partners, *Assessment of Potential Revisions to the Mercury and Air Toxics Standards*, for Center for Applied Environmental Law and Policy, June 15, 2023.

[65] Staudt, J. *Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), April 5, 2022.

[66] *See* 77 Fed. Reg. at 9385.

emissions averaging across the four units to comply with the MATS non-Hg metals emissions standards. Ameren's approach was to replace two of the four ESPs. In Ameren's words, "Ameren retrofitted the entire ESP trains on two units in 2014/2015. On each of these units, two of the three original existing ESPs had to be abandoned and one of the existing ESPs was retrofitted with new power supplies and flue gas flow modifications. A new state-of the art ESP was added to each unit to supplement the retrofitted ESPs."[67] These units are shown in Figure 4. Two new ESPs are apparent in the lighter color and two units are shown to have older ESPs.

Figure 4. New ESPs at Labadie units 1 & 2 and adjacent units 3 & 4 with older ESPs[68]



Gas cofiring or gas conversion

Emissions of HAPs are often related to in the chemical species in the coal.[69] Hg is present in trace concentrations in coal, and if natural gas is substituted for coal, the mercury concentrations at the exhaust entering the control equipment will be reduced in proportion to the gas used, and a reduction in mercury emissions (or, perhaps alternatively, a reduction in activated carbon injection to achieve the same outlet emissions rate) would be expected. Similarly, substitution of natural gas for coal should also reduce HCl emissions or sorbent treatment rates. The emissions of PM

[67] Ameren Missouri comments on EPA's April 2023 proposed MATS revisions submitted to Docket EPA-HQ-OAR-2018-0794.

[68] From Google Earth, with annotation

[69] For example, Hg. HCl, and non-Hg metal emissions are related to the content of Hg, HCl and non-Hg metals in the coal; however, organic HAPs are products of incomplete combustion.

may drop as well, but perhaps not to the same degree as expected for Hg or HCl due to the number of factors that impact PM control equipment performance.

Based upon 2011 US EPA Air Markets Program Data, of the 933 pulverized coal or combination coal- and gas-fired units that were subject to the MATS rule when it was finalized, 929 were listed as only burning coal.[70] Of these 929 units, 73 were shown in 2017 Air Markets Program Data to have opted to refuel their coal boilers with natural gas or a combination of coal and natural gas.[71] The motivation for a facility's decision to change to natural gas as a primary fuel is not included in this data, but it is certain that at those facilities where gas was being fired at a greater rate, it became easier to comply with MATS. For those facilities that fired 90% or more of their heat input as natural gas, they would no longer be subject to the MATS rule.[72]

Refueling or repowering in 2015 and 2016 (the years that MATS limit compliance was required) did occur. During those years EIA determined that of the 299 GW of total coal generating capacity operating at the end of 2014,

- 87.4 GW (29%) added pollution control equipment over those two years
- 73 GW of that capacity (about 25% of all coal capacity) installed ACI Hg controls
- 19.7 GW retired (about 6.7%)
- 5.6 GW of capacity repowered or refueled.[73]

Therefore, repowering with natural gas or refueling the coal steam boiler to natural gas was performed during the compliance period. In fact, EPA stated that repowering to natural gas was a reasonable justification for providing an additional year extension for compliance.[74]

B. Trading and emissions averaging

Emissions trading and emissions averaging are approaches that allow facility owners to focus their efforts on those facilities that are the largest emitters and those that are most cost-effectively controlled. In one form of trading as a compliance mechanism, a total mass emission cap is established for sources within a geographic region. Under this mechanism, "allowances" are available that give a source the legal right to emit a mass of the pollutant within a prescribed period of time. These allowances may be transferred or "traded" to other sources and sold to the owners of those sources. The Title IV Acid Rain Program of the 1990 CAA Amendments

[70] Determined by taking all coal or coal and other fuel electric utility or small power producer units and filtering out CFBs, bubbling bed boilers, stoker boilers and IGCC that operated for a full 12 months and had shown a heat input greater than zero.

[71] Determined by comparing primary fuel in Air Markets Program Data in 2017 to coal units in 2011 (only counting units that had 12 months of data and heat input greater than zero in each case). These years were selected because 2011 was the year MATS was finalized and 2017 was the first full year of data after full MATS compliance.

[72] *See* 40 C.F.R. § 63.10042 (defining "[c]oal-fired electric utility steam generating unit").

[73] https://www.eia.gov/todayinenergy/detail.php?id=26972#

[74] 77 Fed. Reg. at 9410.

introduced this concept for SO_2 emissions. It was later applied for NOx and SO_2 emissions in EPA rules.

Another example of a mass-based cap system is the Regional Greenhouse Gas Initiative (RGGI). RGGI "is a cooperative, market-based effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia to cap and reduce CO_2 emissions from the power sector."[75] Beginning in 2009, it established regional caps for CO_2 emissions from the power sector that have been periodically adjusted.

In addition to mass caps, other options include trading or averaging emissions to achieve an overall emission rate (such as lb/MWh or lb/MMBtu) over one or more jurisdictions or within a system.

1. Title IV Acid Rain Program

Title IV of the 1990 CAA Amendments addressed acid deposition from SO_2 and NOx emissions from coal- and oil-fired power plants. Under this program, EPA established a then novel allowance trading program for SO_2. For SO_2, the goal was to reduce SO_2 emissions by 10 million tons from 1980 levels. This was achieved in a two-phase program:[76]

Phase I (began in 1995)

Affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total number of Phase I affected units to 445.

Phase II (began in 2000)

Added more units to the Acid Rain Program, which with Phase II encompasses over 2,000 units in all. Units that were included for the first time in Phase II included smaller units fired by coal, oil, and gas. The program affects utility units serving generators with an output capacity of greater than 25 megawatts and all new utility units.

Reductions were facilitated through a market-based cap-and-trade system that gave facility owners the ability to trade allowances that were in excess of what they needed for operation of their facilities. In very general terms, Phase I allowances were allocated to various sources based upon historical heat input and an emission rate of 2.50 lb/MMBtu.[77] In addition, allowances could

[75] https://www.rggi.org/. Virginia has recently withdrawn from the program. https://www.townhall.virginia.gov/L/viewchapter.cfm?chapterid=1751.

[76] https://www.epa.gov/acidrain/acid-rain-program#so2reductions

[77] 42 U.S.C. §7651c(e).

be allocated for qualified energy conservation and renewable energy deployment.[78] Phase II allowance allocations would include many more units and be based upon historical heat input and emission rate of 1.20 lb/MMBtu.[79]

Title IV did not prescribe any specific technological solutions for reducing SO_2 emissions. So, facility-owners had the option of adding control technology, changing fuels to lower sulfur fuels or combinations of the two. A challenge associated with reducing fuel sulfur existed for those facilities (the large majority of facilities at the time) that had an ESP as the PM control device. ESP performance is heavily impacted by the charge-carrying property of the fly ash, referred to as "resistivity," which is impacted by the presence of SO_3. Lower SO_3 concentrations will increase fly ash resistivity and will adversely impact performance of the ESP. Absent another technical solution, facilities that reduced fuel sulfur would likely need to increase the size of the ESP to avoid increases in PM emissions. That would increase the capital cost associated with using lower sulfur fuel. Because of the impact of SO_3 on PM emissions, additional control technology – such as SO_2 scrubbers, or FGD, or alternatively, upgrades to ESPs – were expected to play a large role in complying with the Title IV requirements. As will be discussed later, an important technological development would have a large impact on how facilities complied with Title IV.

The Title IV program also established a requirement for use of CEMS on all affected units, which was how emissions were tracked versus the allowances granted. The data from this technology provides important insights to how utilities were able to comply with the Title IV requirements. This data would also become important in development of future rules and would provide the electric utility industry useful data to evaluate the performance of their facilities.

Figure 5 shows reported 1997 emission rates plotted against reported 1990 emission rates.[80] It includes facilities burning coal and facilities burning residual fuel oil. The data for each unit is plotted as a blue square. Also shown as a red line is if 1997 emissions exactly matched 1990 emissions. As shown, most facilities reduced their emission rate, while a handful actually increased their emission rate slightly. For the 256 units shown here, total SO_2 emissions dropped from about 8.6 million tons to about 4.7 million tons. For these 256 units, 2 reported having FGD in 1990 and 29 reported having FGD in 1997. Therefore, 27, or just over 10% of the 256 units represented here, installed some form of FGD between those years. Also, it is apparent that there are many units with emissions over 2.5 lb/MMBtu. In fact, 92 of the 256 units (about 36%) had an SO_2 emission rate over 2.5 lb/MMBtu.

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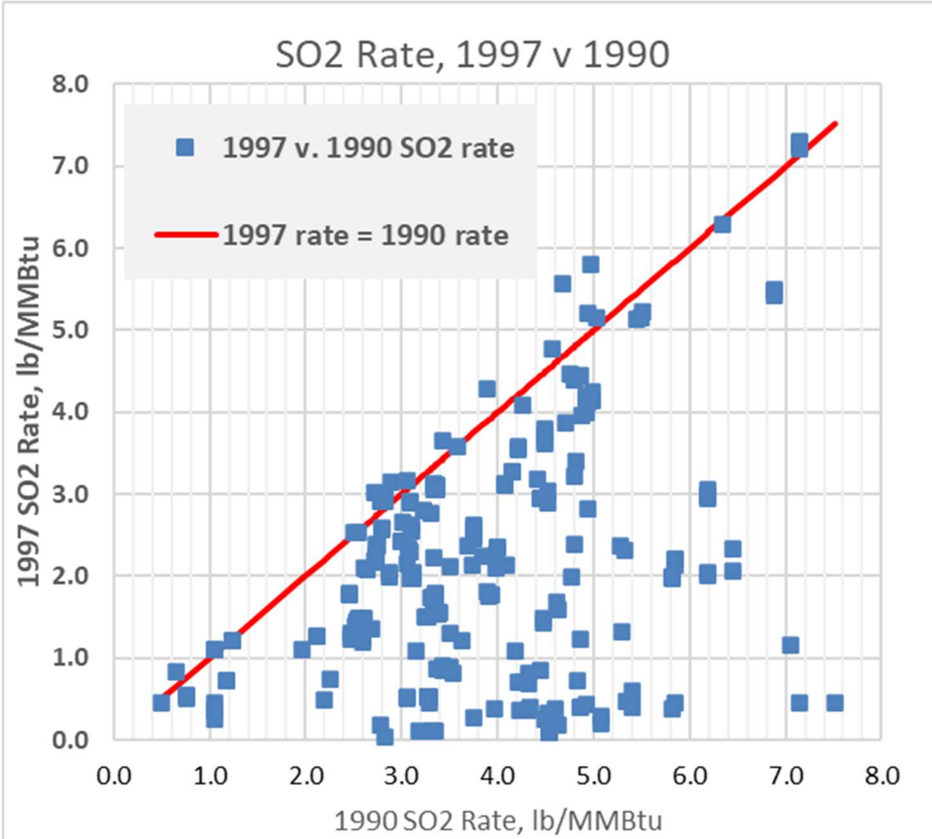
[78] *Id.* § 7651c(f).
[79] *Id.* § 7651c(e).
[80] Calculated by multiplying total reported annual SO_2 emissions in tons by 2000 and dividing by reported annual heat input in MMBtu.

Figure 5. 1997 versus 1990 annual average SO_2 emission rates for 256 Title IV Phase I units[81]



Nearly 90% of the units did not install FGD, and most of them controlled their SO_2 emission rate by changing to lower sulfur fuel through changing to lower sulfur coal or blending in lower sulfur fuel with the historical fuel. A significant number of units did not change their emission rates. For 48 units (18.8%), the 1997 emission rate is within 10% of the 1990 emission rate. These facilities essentially made no changes. As a result, the 256 Phase I affected facilities represented here did one of the following to comply with the Phase I Title IV requirements:

1. No change; they continued to use the same fuel as before and did not install FGD (about 18.8%)
2. Installed FGD (about 10.5%)
3. Changed the fuel or fuel mix to incorporate the use of lower sulfur fuels (about 70.7%)

This was made possible through certain technical developments:

[81] Data from 1990 and 1997 Air Markets Program Data

- *CEMS* – Although CEMS had been deployed on a limited basis up until this point, Title IV required deployment of CEMS on all affected units. The increased use of CEMS motivated greater technological development in this area, to include sensors, equipment, and reporting software.
- *Flue Gas Conditioning (FGC)* – While most sulfur in the coal is oxidized to SO_2, a small portion of the sulfur in the coal is oxidized to SO_3. The use of low sulfur coal would impact PM emissions from ESPs, as SO_3 concentrations impact resistivity of fly ash, affecting performance of ESPs. FGC, or injection of small amounts of SO_3 upstream of the ESP, would allow facilities to reduce their fuel sulfur without adversely affecting the performance of their ESP. The technology was only made available around the time of the 1990 CAA Amendments, and the patent for this technology would not be published until 1993, well after the 1990 CAA Amendments were enacted.[82] This was a critical technology development that altered how companies chose to comply with the Title IV requirements. It dramatically reduced the cost of switching to lower sulfur fuels because otherwise it would have been necessary to make more expensive modifications to PM control equipment or, alternatively, install an SO_2 scrubber without flue gas conditioning. This technology development played a major role in facilitating the widespread use of lower sulfur coals to comply with Title IV and dramatically reduced the cost of compliance with Title IV.

The development of FGC is an example of a technology that was developed to facilitate a lower cost means of complying with Title IV – fuel switching. This is the type of technical innovation that is possible when EPA sets emissions performance standards rather than specifying a particular technology. Further, sources or owners were motivated to find a less costly approach to comply with the regulation, like by installing FGC and switching fuels, in order to potentially generate tradeable emission allowances. When the cost of a potential control technology is less than the value of the allowances or the cost of other alternatives, this stimulates innovation and wider deployment of the technology.

2. Ozone Transport Commission Memo of Understanding (OTC MOU), NOx SIP Call, Clean Air Interstate Rule (CAIR), and Cross-State Air Pollution Rule (CSAPR)

These rules were developed out of the "good neighbor provision" of the CAA, Section 110(a)(2)(D)(i)(I),[83] which requires states to address the interstate transport of air pollution. Specifically, the good neighbor provision requires that each state implementation plan (SIP) contain adequate provisions to prohibit air pollutant emissions from within the state that will significantly contribute to nonattainment of the national ambient air quality standards (NAAQS),

[82] US patent No. 4779207A, published June 6, 1993.
[83] 42 U.S.C. § 7410(a)(2)(D)(i)(I).

or that will interfere with maintenance of the NAAQS, in any other state.[84] The 1990 CAA Amendments identified a region in the northeast U.S. to be called the Ozone Transport Region (OTR) where transport of ozone and precursors was a problem. It also gave the EPA Administrator the authority to establish interstate transport commissions.[85]

> *"A single transport region for ozone (within the meaning of section 7506a(a) of this title), comprised of the States of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and the Consolidated Metropolitan Statistical Area that includes the District of Columbia, is hereby established by operation of law."*[86]

Being designated as a single, nonattainment region for ozone, the OTR would have to develop rules to address ozone transport within the OTR. In addition, the Ozone Transport Assessment Group (OTAG) was developed to assess transport of ozone and ozone precursors from additional areas in the U.S., especially the Midwest to the Northeast.[87] As a result of these efforts to control interstate transport of ozone, a number of rules were developed to address concerns about interstate transport of ground-level ozone and ozone precursors in the eastern U.S. (OTC MOU[88] and the NOx SIP Call[89]), and transport of ground-level ozone and ozone precursors as well as fine PM and fine PM precursors (CAIR and CSAPR).[90] Each of these programs established state objectives or state budgets for emissions of NOx (all four programs) and SO_2 (CAIR and CSAPR). In each of these programs, states had the option to achieve the required emission reductions through their SIPs, determining how they would meet the budget for the affected sources within their state. Absent an acceptable SIP, EPA would issue a federal implementation plan (FIP) for the state. Some specific examples of SIPs will be discussed later in this document.

During CAIR[91] and CSAPR implementation, the Regional Haze Rule (RHR)[92] was also being implemented. The RHR was intended to address the adverse impacts of fine PM on visibility in sensitive areas, such as national parks, and therefore impacted facilities in western states in

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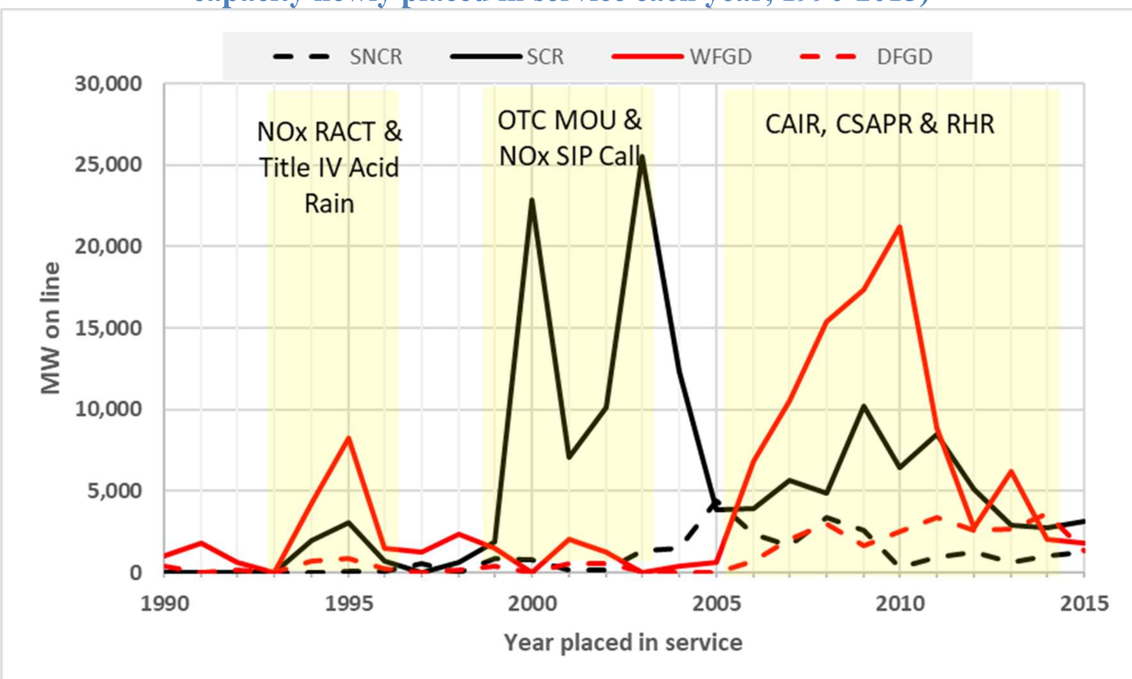
[84] *Id.*
[85] *Id.* § 7506a and § 7511c(a).
[86] *Id.* § 7511c(a).
[87] https://archive.epa.gov/ttn/ozone/web/pdf/otagfs.pdf
[88] https://otcair.org/upload/Documents/Formal%20Actions/MOU%2094_2.pdf
[89] https://archive.epa.gov/ttn/ozone/web/pdf/noxsipf-3.pdf
[90] https://www.epa.gov/sites/default/files/2015-08/documents/cair09_ecm_analyses.pdf
https://www.epa.gov/Cross-State-Air-Pollution/overview-cross-state-air-pollution-rule-csapr#overview
[91] The D.C. Circuit held CAIR invalid and vacated the rule in 2008; however, the court subsequently allowed the program to remain in effect while EPA remedied its defects. *See North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008); *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008).
[92] https://www.epa.gov/visibility/1999-regional-haze-rule-protection-visibility-national-parks-and-wilderness-areas

addition to the primarily eastern and midwestern states largely impacted by CAIR and CSAPR.[93] States submitted plans responding to the RHR from 2004 through 2018.[94]

Figure 6 shows the history of NOx and SO_2 emission control installations from 1990 through 2015 and associated EPA programs, showing the MW of coal-fired generation newly equipped with the technology in each year. As shown, in the years from 1999 to 2003 there was a large increase in new SCRs placed in service. And, from 2005 to 2015, there was a large increase in FGDs and, to a lesser degree, SCRs placed in service. As shown, the amount of FGD installed in response to CAIR, CSAPR and the RHR was far greater than in response to the Title IV acid rain provisions of the 1990 CAA Amendments.

Figure 6. History of post-combustion NOx and SO_2 controls for coal EGUs (MW of capacity newly placed in service each year, 1990-2015)[95]



a. OTC MOU and NOx SIP Call

The OTC MOU and the NOx SIP Call were developed in response to concerns about interstate transport of ground-level ozone and ozone precursors in the eastern U.S. In September 1994 the OTC issued the OTC MOU that established that the states would develop budgets for NOx emissions by March 1995. The OTC MOU would be incorporated into SIPs for states in the

[93] 64 Fed. Reg. 35,714 (July 1, 1999).
[94] https://www.epa.gov/sites/default/files/2015-05/documents/implemnt.pdf
[95] Developed from the US EPA National Electronic Energy Data System, includes all pulverized coal, cyclone, vertical fired coal EGUs.

OTR. The budgets would require NOx reductions in two phases – by 1999 and by 2003. The budget for 2003 would be more stringent and based upon an average rate of 0.15 lb/MMBtu.[96]

Finalized in 1998, the NOx SIP Call imposed ozone season NOx emissions budgets for 20 eastern states and the District of Columbia to revise their SIPs to reduce seasonal NO_X emissions contributing to interstate ozone pollution. Implementation of emission controls under the NOx SIP Call began in 2003 and, like the OTC MOU, the rule established state NOx budgets using an average emission rate of 0.15 lb/MMBtu for all fossil EGUs.[97] Both of these programs used allowance trading mechanisms. As described in more detail by ATP and as demonstrated in Figure 6, in 1998 there were installations of post-combustion NOx controls, but they were fairly limited.[98] Figure 6 demonstrates there was a large increase in SCR installations that coincided with implementation of the OTC MOU and NOx SIP Call. In 2000, nearly three times as much coal-fired SCR capacity was placed in service than had been installed in all of the years prior to 2000. By 2007, nearly 100 GW of coal capacity would be equipped with SCR. As shown in Table 1, EPA assessed in the RIA for the NOx SIP Call how coal units would respond to budgets based upon different average emission rates. As the emission rate associated with the NOx SIP Call budget decreased, greater amounts of SCR were forecast to be installed by 2007 in response to the rule. In fact, fewer SCR systems were projected than were actually installed at the 0.15 lb/MMBtu rate that was ultimately used to establish budgets, given better cost-effectiveness of SCR systems than EPA had assumed, particularly for large units.

Table 1. Estimated emission control responses for coal-fired steam units to the NOx SIP Call in 2007 (MW capacity for the SIP Call Region)[99]

Emission Control Response	0.25 Trading	0.20 Trading	0.15 Trading	0.12 Trading
Close Unit	18	16	113	183
Comply with BACT	4,158	4,158	4,158	4,158
Title IV NOx Controls Only *	97,895	40,242	4,545	4,879
Add SNCR	93,003	133,240	129,690	83,172
Add SCR	7,208	23,384	63,267	109,761
Add Gas Reburn	-	1,242	509	129

Source: ICF analysis

* This row shows the MW capacity adding *only* Title IV NOx controls. Therefore, the numbers tend to decrease with increases in option stringency.

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[96] https://otcair.org/upload/Documents/Formal%20Actions/MOU%2094_2.pdf

[97] 83 Fed. Reg. 48,751, 48,751 (Sept. 27, 2018) (proposed rule); 63 Fed. Reg. 57,356, 57,362, 57,378, 57,433, 57,475 (Oct. 27, 1998).

[98] Andover Technology Partners, for Northeast States for Coordinated Air Use Management, *Status Report on NOx: Control Technologies and Cost Effectiveness for Utility Boilers*, June 1998.

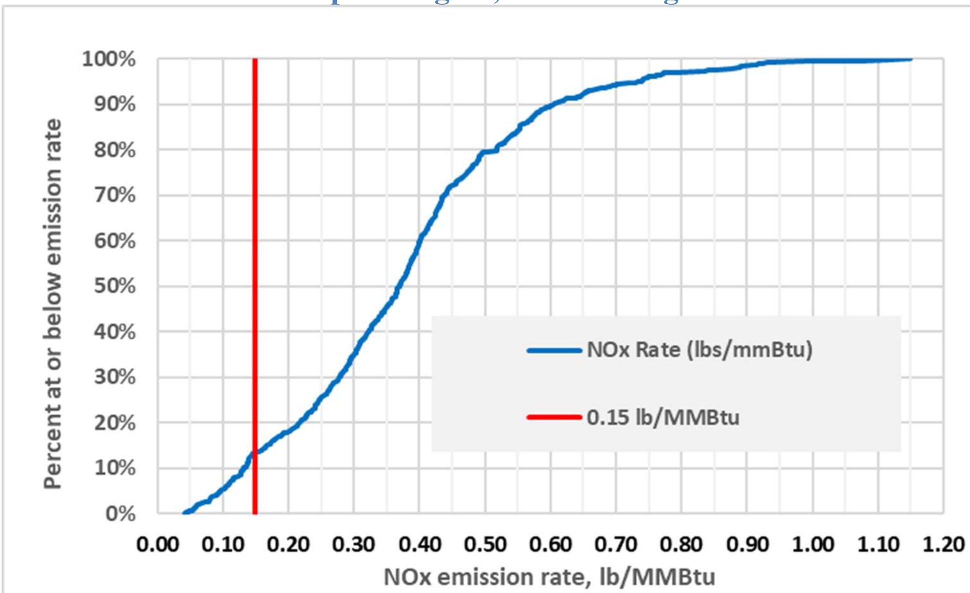
[99] US EPA, *Regulatory Impact Analysis For the NOx SIP Call, FIP, and Section 126 Petitions*, EPA-452/R-98-003A, September 1998, p. 6-2.

As Figure 6 demonstrates, SNCR was not used on as much capacity as SCR and, looking at the OTC MOU and NOx SIP Call period, tended to be installed later than SCR. Not as much SNCR would be installed as forecast by EPA in the RIA (see Table 1 above). SCR would generally be favored over SNCR. This is explained by the fact that utilities tended to install SCR on larger units, where such capital-intensive projects were most economical and could reduce the greatest amount of NOx mass emissions. Over the entire period represented in Figure 6, the average size of SCR-equipped units was 505 MW while the average size of SNCR-equipped units was 209 MW. From a system planning perspective (with regard to generation and also with regard to compliance with an overall mass emission budget), the large units were the most important facilities, and therefore received the greatest priority. Smaller, less critical facilities would then be retrofit with SNCR afterwards as companies worked through the larger, SCR projects and could then evaluate their needs for the smaller facilities. This is another example of how EPA's approach to reducing emissions of ozone and fine PM precursors provided companies flexibility to select the strategy that best suited their needs.

Because the state ozone season NOx budgets for EGUs were based upon an emission rate of 0.15 lb/MMBtu for all fossil EGU sources, coal units did not necessarily need to retrofit NOx controls because gas-fired facilities would generally have emissions rates well below 0.15 lb/MMBtu and could be relied upon more heavily to comply with the overall limit, yet some coal units did retrofit controls. An evaluation of 2003 ozone season emissions for the NOx SIP Call affected states found 717 coal EGUs[100] in total. Of them, 97 had ozone season emissions levels below 0.15 lb/MMBtu. Of the 717 units, 95 were equipped with SCR in 2003, having emission rates ranging from 0.042 lb/MMBtu to as high as 1.15 lb/MMBtu. Of the 95 units with SCR, 50 had emission rates below 0.15 lb/MMBtu. Most of the other 47 units with emission rates below 0.15 lb/MMBtu were units firing Powder River Basin (PRB) coal, which is low in nitrogen content, and were equipped with low-NOx combustion controls. Figure 7 shows a cumulative distribution of ozone season emission rates for coal-fired boilers. As shown, 14% of the facilities had emission rates below 0.15 lb/MMBtu. The median emission rate was 0.37 lb/MMBtu.

[100] 2003 AMPD, looking only at coal EGUs with pulverized coal, cyclone, arch or vertical firing. These are generally the largest units and tend to be the highest emitting.

Figure 7. 2003 ozone season emission rate for 717 coal-fired EGU boilers in the Ozone Transport Region, lowest to highest



It is apparent that the OTC MOU and the NOx SIP Call permitted substantial flexibility in control:

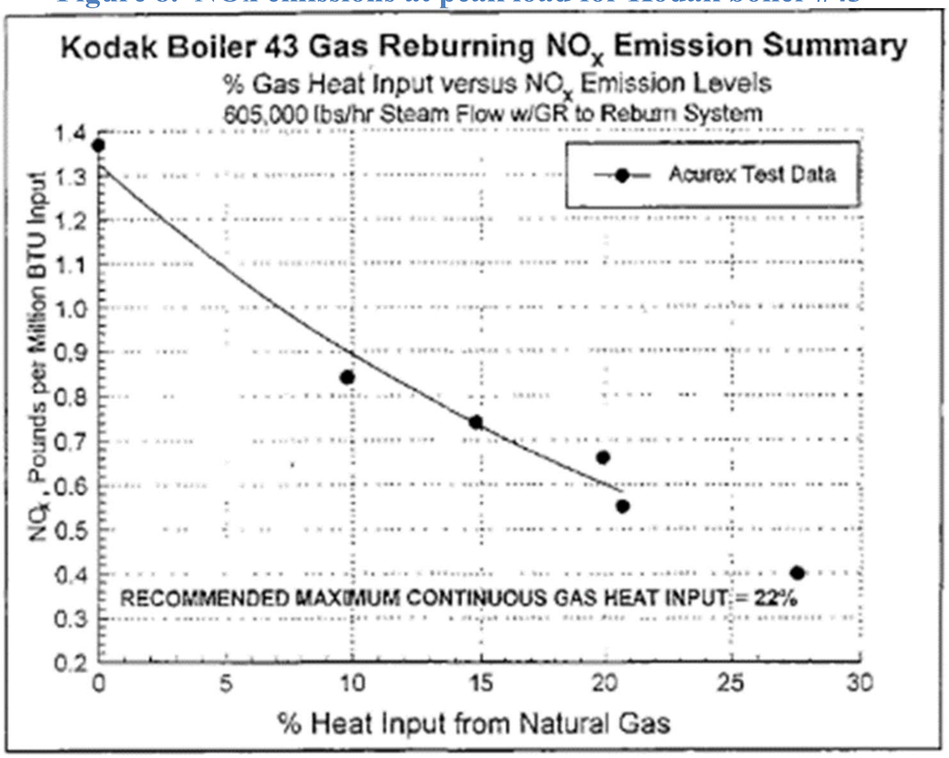
1. These policies permitted compliance using a total mass budget, so that low-emitting units could offset high-emitting units. This also allowed facility owners to prioritize the most critical facilities first, and then focus their efforts on less critical facilities.
2. Some coal units were equipped with NOx emission controls, while some were not as well controlled.
3. Utilities could take advantage of lower emitting fuels, such as natural gas. Coal units might co-fire natural gas. Or, generation might shift to natural gas combined cycle units that are very well controlled.

In addition to post-combustion controls like SCR and SNCR and combustion controls, some coal-fired facilities utilized natural gas-based technologies to reduce NOx. These might include co-firing natural gas or using gas reburning technology to reduce NOx even further. The following is an example.

Kodak Boiler, Rochester, NY

Eastman Kodak's world headquarters at Kodak Park in Rochester, NY, had a large facility to provide steam, electricity, and other utilities to the site. At the facility, Kodak had several coal-fired cyclone boilers. The boilers were subject to controls for the OTC MOU. In an effort to reduce NOx emissions at the site, Kodak agreed to reduce NOx emissions from two of the boilers through technology demonstration programs. Existing, uncontrolled NOx emissions were 1.37 lb/MMBtu and 1.36 lb/MMBtu on the two boilers. The presumptive limit imposed by the State of New York was 0.60 lb/MMBtu, or about a 52% reduction from baseline. As cyclone boilers, combustion control options were limited. Kodak could not use SNCR or SCR technology because even small amounts of ammonia on site could potentially have a major, adverse impact on Kodak's manufacturing operations. They settled on use of natural gas reburn, a technology where roughly 20% of the boiler heat input would be introduced in the form of natural gas after the coal combustion zone and then followed by overfire air to burn out the remaining fuel.[101] Figure 8 demonstrates the effect of increasing natural gas input on NOx emissions for one of the two boilers.

Figure 8. NOx emissions at peak load for Kodak boiler #43[102]



Joliet Station 9

Joliet Station 9 Unit 6 (Joliet 6) was a 327 MW cyclone-fired boiler. The acid rain provisions of the 1990 CAA Amendments required Joliet 6 to meet an annual average NOx emission rate of 0.86 lb/MMBtu beginning in 2000, and Illinois would also be subject to the NOx SIP Call that would establish a NOx emissions budget for Illinois. In early 1997, the boiler was emitting 0.96 lb/MMBtu. Commonwealth Edison of Chicago installed a fuel-lean gas reburn (FLGR). FLGR is capable of reducing NOx in a simpler system than for normal gas reburn (such as that used at the Kodak boilers). FLGR does not require the addition of an overfire air system.

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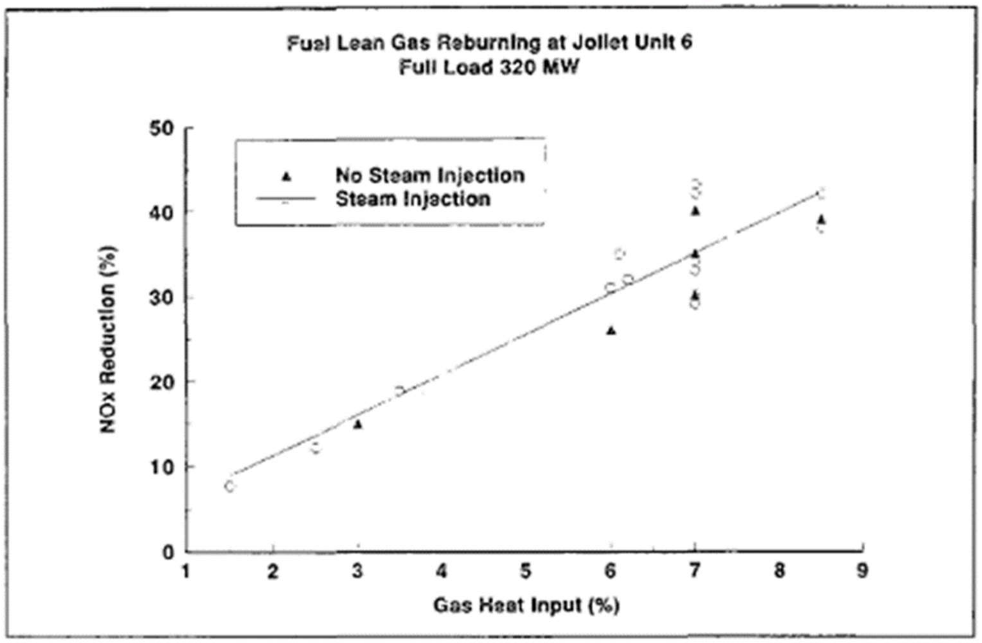
[101] Andover Technology Partners, for Northeast States for Coordinated Air Use Management, *Status Report on NOx: Control Technologies and Cost Effectiveness for Utility Boilers*, June 1998, p. 166.

[102] Farzan, H., et al., "NOx Control Using Natural Gas Reburn on an Industrial Cyclone Boiler", 1997 EPRI-DOE-EPA Combined Utility Air Pollution Control (MEGA) Symposium, August 25-29, 1997, Washington, DC.

The technology was shown at Joliet 6 to be capable of about 30%-40% NOx reduction while using only about 7% of its heat input as natural gas, as demonstrated in Figure 9.

Figure 9. Percent NOx reduction versus gas input at Joliet 6[103]



b. CAIR and CSAPR

CAIR was initially promulgated in 2005 as a two-part program to address interstate transport of air pollution in the eastern U.S., especially ozone and fine PM and their precursors. While the first part of CAIR proceeded, CAIR was remanded, and would stay in place until ultimately replaced by CSAPR.[104] CSAPR, finalized in 2011, would address the court's concerns with CAIR and required 28 eastern states to reduce power plant emissions – NOx and SO_2 in particular.[105]

In US EPA's October 2005 analysis of CAIR,[106] the agency projected retrofits of roughly 90,000 MW of new FGD systems and 37,000 MW of new SCR systems as retrofits on existing

103 Glickert, R., et al., "Application of Fuel Lean Gas Reburn Technology at Commonwealth Edison's Joliet Generating Station 9", 1997 EPRI-DOE-EPA Combined Utility Air Pollution Control (MEGA) Symposium, August 25-29, 1997, Washington, DC.

104 While initially vacated, CAIR was ultimately remanded by the U.S. Court of Appeals for the District of Columbia Circuit on December 23, 2008 (https://archive.epa.gov/airmarkets/programs/cair/web/pdf/cairremandorder.pdf) and would ultimately be replaced by CSAPR.

105 76 Fed. Reg. 48,208, 48,211 (Aug. 8, 2011).

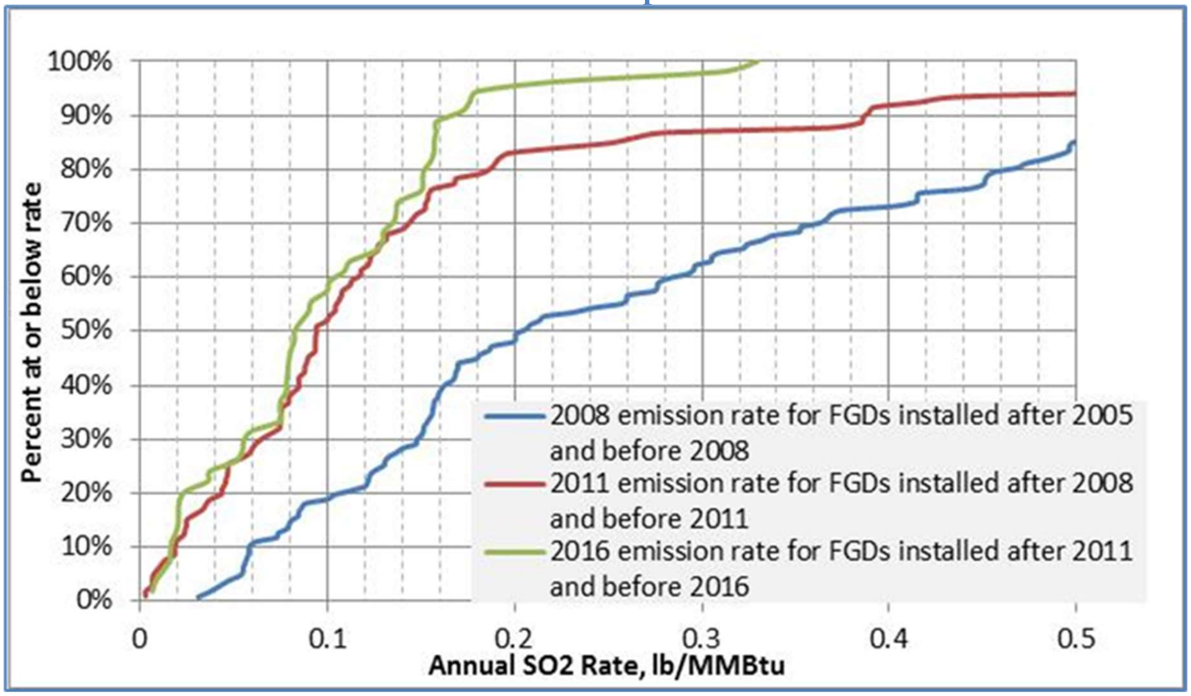
106 US EPA, "Multi-Pollutant Regulatory Analysis: CAIR/CAMR/CAVR", October 2005, http://www.epa.gov/airmarkets/progsregs/cair/docs/cair_camr_cavr.pdf; *see also* Staudt, J., "White Paper – Availability of Resources for Clean Air Projects", October 1, 2010, at: https://www.andovertechnology.com/wp-content/uploads/2020/07/14_white-paper-availability-of-resources-for-clean-air-projects_public.pdf, p. 4.

sources by 2020. An additional 22,700 MW of SCR and FGD was expected for new power plants (new coal plants were assumed to be built with both). US EPA expected 36,000 MW of FGD and 15,000 MW of SCR to be completed by 2010 for Phase I. The forecasts for 2020 would prove to be relatively accurate, but installations actually occurred a bit more swiftly.[107] The data from Figure 6 demonstrates that in the years 2006 through 2015, 54,500 MW of SCR would be installed (total for new and retrofit), and 126,800 MW of FGD (both wet and dry FGD for new and retrofit FGD). The Regional Haze Rule (RHR) would also have a significant impact on increasing the levels of SCR and FGD installed.

The use of FGD due to CAIR and CSAPR (and the RHR) motivated advancements in FGD technology and improvements in operation. This is demonstrated by improved emission rates from installed FGD systems. Figure 10 compares SO_2 emission rates of FGD systems installed in different time periods. The data is displayed in this figure as the percentage of units emitting at or below a given emission rate, and the figure generally shows greater percentages of units complying at lower emission rates for systems installed in later time periods. The reduction in emission rates for the entire fleet of FGD systems is also due to improvements to existing FGD systems deployed partly in response to the Mercury and Air Toxics Standards (MATS). For example, wet FGD systems installed after January 1, 2005, but before January 1, 2008, had a median 2008 SO_2 emission rate of 0.201 lb/MMBtu. Wet FGD systems installed after January 1, 2008 but before January 1, 2011 had a median 2011 SO_2 emission rate of 0.094 lb/MMBtu. Wet FGD systems installed after January 1, 2011, but before January 1, 2016, had a median 2016 SO_2 emission rate of 0.082 lb/MMBtu. Of 144 FGD systems operating for a full year in 2008 that were also operating for a full year in 2016, two thirds had reduced their emission rate between 2008 and 2016 and most of the improvement occurred after 2011.

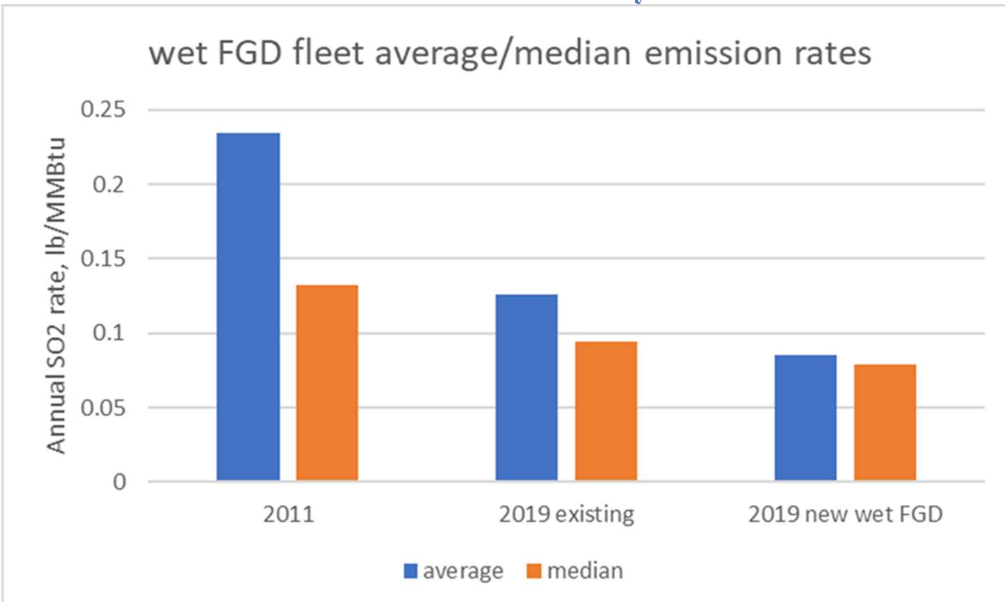
[107] Andover Technology Partners, "White Paper – Availability of Resources for Clean Air Projects", October 1, 2020, pp. 18-19; Available at: https://www.andovertechnology.com/wp-content/uploads/2020/07/14_white-paper-availability-of-resources-for-clean-air-projects_public.pdf. This demonstrates that many of the installations forecast to result from CAIR were in fact ordered prior to finalization of the rule.

Figure 10. Cumulative plot of annual SO_2 emission rates for wet FGD systems installed in different time periods



In addition to the effect of new FGD systems having improved performance over older systems, existing facilities were able to improve performance. As shown in Figure 11, wet FGD systems that were operating in 2011 (the last full year of operation before MATS was finalized) experienced a significant improvement in SO_2 emission rate by 2019. This was likely a result of FGD improvements used to comply with MATS as well as to reduce SO_2 emissions for other programs. The figure also shows the average and median SO_2 emission rate for new wet FGD systems installed since 2011. As shown, these facilities were capable of even lower emission rates.

Figure 11. Average and median annual SO_2 emission rate for wet FGD systems operating the full year in 2011, 2019 emissions of units with wet FGD systems operating in 2011, and 2019 emissions of units with new wet FGD systems built since 2011[108]



C. State emissions control strategies, including emissions averaging, developed to comply with CAA requirements

NAAQS are periodically updated for NO_2, SO_2, ground-level ozone, and fine PM –which are variously impacted by NOx and SO_2 emissions. Although the CAA gives EPA the authority to establish NAAQS, it is up to the states to formulate and document how they will meet NAAQS in their SIPs.[109] Many states had the opportunity to craft state programs that would meet the requirements of multiple programs, such as CAIR, CSAPR, and the RHR. States also had the primary role in designing plans to implement the Clean Air Mercury Rule (CAMR),[110] which was later vacated and replaced with MATS.[111]

The following are examples of state programs that were incorporated into SIPs for meeting NAAQS (NOx SIP Call, CAIR, CSAPR, etc.), the RHR, CAMR, and other requirements.

1. Illinois Multi-Pollutant Standard (MPS)

- In 2006, Illinois amended Part 225 of their requirements for control of emissions from large combustion sources. This was designed to address requirements to meet

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[108] Staudt, J. Andover Technology Partners, *Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants,* for Center for Applied Environmental Law and Policy (CAELP), April 5, 2022, p. 16.
[109] 42 U.S.C. § 7410.
[110] 70 Fed. Reg. 28,606, 28,633 (May 18, 2005).
[111] *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008); 77 Fed. Reg. at 9308.

NAAQS (including through CAIR, and later CSAPR), RHR requirements, and CAMR, vacated in 2008. These changes included:

Mercury Standard

- Requirements to control mercury emissions from coal-fired EGUs. This was crafted to comply with CAMR. The Illinois rule required 90% mercury reduction on all units by the end of 2008.

An alternative, Multi-Pollutant Standard (MPS)

- The Illinois multi-pollutant rule was finalized in 2006. It established emissions limits for NOx, SO_2 and Hg to meet needs of CAIR, the RHR, and CAMR:
  - Established fleetwide emission rate standards for NOx and SO_2 for MPS groups. Fleetwide average NOx emission rate for 2012-2018 could not exceed 0.11 lb/MMBtu. Beginning 2019, total fleetwide NOx emissions could not exceed 19,000 tons annually and 11,500 tons during the ozone season.
  - Fleetwide standards for SO_2, beginning 2013 and into 2014 of 0.33 lb/MMBtu, 0.25 lb/MMBtu 2015-2018, and maximum annual SO_2 mass emissions beginning 2019 (the mass emissions determined by the units involved).
  - Hg emission reductions were also staged in depending upon certain factors.

These changes allowed facility owners the flexibility to identify those facilities that are best suited to retrofit with emissions control technologies.

2. North Carolina Clean Smokestacks Act (CSA)

North Carolina passed its Clean Smokestacks Act in June 2002. The CSA was developed to address NAAQS and RHR requirements. It would also contribute to compliance with future HAP regulations. Specifically, the CSA:

- Established NOx and SO_2 mass emission limits for utility power plants in 2007, 2009, and 2013.
- Was important in helping North Carolina meet requirements for reduction of regional haze, fine PM, and ozone NAAQS.
- Set a combined limit of 130,000 tons/yr of SO_2 and 56,000 tons/yr of NOx on Duke Energy and Progress Energy coal-fired units in NC. Table 2 shows the limits and their deadlines along with the historical 2000 emissions.

Table 2. Clean Smokestacks limits and historical emissions

		Clean Smokestacks Limits			
NOx	**2000**	**2007**	**2009**	**2013**	
Progress	63,494	25,000	25,000	25,000	tons/yr
Duke	96,466	35,000	31,000	31,000	tons/yr
SO_2	**2000**	**2007**	**2009**	**2013**	
Progress	205,256	None	100,000	50,000	tons/yr
Duke	248,107	None	150,000	80,000	tons/yr
	2000	**2007**	**2009**	**2013**	
Total NOx	159,960	60,000	56,000	56,000	tons/yr
Total SO_2	453,363	None	250,000	130,000	tons/yr

The CSA provided means for the utilities to recover investments in air pollution control technology, which included FGD and SCR at Duke and Progress coal-fired plants. The two utilities had flexibility in how they would comply with the CSA. Duke and Progress also retired some older units during this period, while replacing them with well-controlled coal units. For example, Cape Fear Units 5 & 6 and LV Sutton Units 1-3, a total of 903 MW of capacity not equipped with SCR or FGD, would be retired by 2013. Cliffside 6 (later, James M. Rogers Energy Center) was a new, state-of-the-art 800 MW coal plant that was placed in service in 2012. It was equipped with state-of-the-art emission controls, including wet FGD, SCR, a dry scrubber and a baghouse. It also used closed-loop cooling.[112] Also, between 2002 and 2012, an additional 2,886 MW of natural gas combined cycle capacity was installed in North Carolina.[113] In effect, in response to the CSA, Duke and Progress shifted generating capacity from relatively uncontrolled units to much lower emitting coal and gas units.

3. Colorado Clean Air Clean Jobs Act (CACJA)

The CACJA was passed in 2010. The legislative declaration stated:

(1) THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM COAL-FIRED POWER PLANTS WILL ENABLE COLORADO UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL

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[112] Duke Energy, Cliffside Modernization Brochure

Overton, T., "Top Plant: Cliffside Steam Station Unit 6, Cliffside, North Carolina", *Power Magazine*, 10/1/2013.

Lancaster, H., "Cliffside Unit 6 Integrated Air Quality Control System", 2008 Mega Symposium, Baltimore, MD, August 28, 2008.

[113] Developed from National Electric Energy Data System, NEEDS v5.13.

APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS WILL ALSO RESULT IN REDUCTIONS IN CARBON DIOXIDE AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO'S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO'S ECONOMY AND INDUSTRY.[114]

The CACJA was therefore designed to address NAAQS and RHR requirements while transitioning to lower-carbon energy sources and allowing utilities to do it in a coordinated way. Some key aspects of this rule included the following:

- Required retirement of a minimum of 900 MW or 50% of coal capacity, whichever is less, by January 1, 2015. In 2013 Colorado had over 20 coal units larger than 25 MW with a combined capacity of 5,338 MW; by the end of 2025 no more than 12 units with a combined capacity of 4,012 MW would be in service.[115]
- Encouraged replacement of coal capacity with lower carbon generating sources, such as natural gas and energy efficiency. From 2012 to 2021, nearly 900 MW of combined cycle capacity would be added, 220 MW of combustion turbines would be added, and 1038 MW of new renewable energy (wind, solar PV, and hydro) would be added.[116]
- Allowed for long-term gas supply agreements.
- Allowed for cost-recovery mechanisms.

As shown, the CACJA was developed to meet the then current and anticipated needs while offering utilities the flexibility to meet these needs in a coordinated fashion with significant input to the decisions on how to meet these needs.

4. Maryland Healthy Air Act (MDHAA)

"*The Maryland Healthy Air Act . . . was developed with the purpose of bringing Maryland into attainment with the National Ambient Air Quality Standards (NAAQS) for ozone and fine particulate matter by the federal deadline of 2010. The act and the subsequent regulations also requires the reduction of mercury emissions from coal-fired electric generating units and significantly reduces atmospheric deposition of nitrogen to the Chesapeake Bay and other waters of the State.*"[117]

The MDHAA required SO_2 emissions reductions from the largest sources, the state's coal-fired boilers, by 80% in 2010 and 85% in 2013. NOx emissions were also required to be reduced by 70% in 2009 and 75% by 2012. These were overall mass emissions limits. Facility owners would choose where to implement controls and what controls to implement.

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[114] https://leg.colorado.gov/sites/default/files/images/olls/2010a_sl_140.pdf
[115] NEEDS v 5.13, v620 and rev 08-07-2023
[116] NEEDS rev 08-07-2023
[117] https://mde.maryland.gov/programs/air/pages/md_haa.aspx

Utilities also had flexibility to choose control technologies for the units that did seek to reduce emissions. While the largest coal units installed FGD and (if they had not already done so) SCR, several units used other controls. For example, FGD and SCR was added at some large coal units (i.e., Brandon Shores and Morgantown plants, with equipment placed in service between 2007 and 2010), but smaller facilities, such as Chalk Point, CP Crane, Dickerson, and Herbert Wagner Unit 2 would install SNCR during the years 2005-2009.[118] SCR would continue to be operated at Wagner Unit 3 and on both Brandon Shores units. Wagner Unit 3 and Brandon Shores were already equipped with SCR that was installed in 2000 for Brandon Shores and 2002 for Wagner Unit 3 to satisfy the requirements of the NOx SIP Call and OTC MOU.

V. Conclusion

The regulatory approaches and case studies discussed in this report illustrate that compliance flexibilities available to owners and operators of stationary sources are a feature of EPA regulations under the CAA. and that those compliance flexibilities further Congress's goals. Air pollution limits in the form of performance standards rather than technology requirements allow owners and operators to choose from an array of controls, including emerging techniques, in meeting the standards considering the particular circumstances of their sources. Furthermore, the ability to trade or average emissions across sources in some regulatory contexts has enabled owners and operators to identify the most cost-effective control strategies for a diverse set of sources and promoted development of a wide range of technologies in achieving public health and environmental objectives. States' efforts in implementing certain EPA rules under the CAA have incorporated many of the same flexibilities, and they have often taken advantage of the opportunity to transition to cleaner methods of production. Together, these compliance flexibilities have secured greater reductions in harmful air pollution at lower cost than would have been possible with more-rigid requirements, and they have advanced the congressional purpose of developing emerging technologies for air pollution control.

[118] See NEEDS v 5.13 and v620

VI. Appendix

A. Explanation of Figure 1

While there are some clear trends in the data represented by Figure 1, there are a few data points that require some additional explanation. First, in the early years shown on this figure, there were some inconsistencies in how the data was being entered into RBLC. Also, in the years immediately after the 1977 CAA Amendments, 1979 NSPS and the introduction of the PSD program, there were also inconsistencies in how EPA regions were applying the emission control requirements of the rules. This would later be addressed in the late 1980s when EPA issued new guidance on how to make a BACT determination.

1. Scrubbed units with emission rate at or about 1.2 lb/MMBtu

There are several situations in Figure 1 that show an emission limit of 1.2 lb/MMBtu for units equipped with a scrubber. These facilities also have percent reduction specified in the permit that is not shown in the figure. As an example, one unit in this figure with a permit in 1986 that shows a limit of 1.2 lb/MMBtu and 80% SO_2 reduction DFGD is Hunter Unit 2 in Utah. According to Air Markets Program data, in 1990 that unit emitted 1,240 tons of SO_2 with a heat input of $3.08(10)^7$ MMBtu, or an average emission rate over the year of 0.081 lb/MMBtu. So, in the case of Hunter Unit 2, although 1.2 lb/MMBtu was the stated maximum outlet rate per the permit, at least 80% emissions reduction was also required and apparently was achieved using a dry FGD process. This is also the case in many of the other facilities shown that have emission rates of 1.2 lb/MMBtu while specifying DFGD or WFGD.

2. Facilities not equipped with a scrubber, and misapplication of requirements early in the years after the 1977 CAA Amendments

Four facilities shown in Figure 1 were not equipped with a scrubber although NSPS indicated that a scrubber was required. Permits are issued by the state agencies under authority granted by US EPA and are reviewed by different EPA regional offices. NSPS had recently changed, and BACT was a new requirement introduced with the 1977 CAA amendments. As a result, when these requirements were being implemented in the late 1970s and early 1980s, there were some inconsistencies between how states and regions implemented them. While the requirements of the new source rule clearly indicate that scrubbers should be deployed, some facilities that commenced construction after September 18, 1978, received a new source permit that did not require scrubbers. Among them: Louisa Generating Station in Muscatine, Iowa, with its permit issued in June 1981.[119] A small (under 50 MW) ETSI plant in Arkansas with a permit

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[119] In a public meeting on the Louisa Generating Station PSD permit held September 16,1980, in Muscatine County Courthouse in Muscatine, IA, it is apparent that the Louisa permit was originally issued by EPA on August 7, 1979, but then reconsidered based upon issues raised by community groups. This permit was being challenged because

issued in 1983 and a Virginia Power plant with permit issued in 1984 received a new source permit but was not required to install a scrubber. In each of these three cases, NSPS was specified in the permit, but according to the RBLC data, the permit also stated that no controls were feasible. In addition to those three plants, there was also a power plant built by Arkansas Power and Light, with its permit issued in early 1978, and therefore construction may or may not have commenced prior to September 18, 1978. Because the RBLC relies upon voluntarily submitted information from each EPA Region, it is likely incomplete, and there are very likely some permits from that period that are not included in the RBLC. But, these permits (and perhaps some others that are not in the RBLC) show that there were some inconsistencies in how the standards were being applied in the early 1980s.

Community Action Research Group believed that Louisa should have a scrubber installed per the latest new source requirements. Based upon the RBLC, the permit was finalized in June 1981. The plant was, in fact, constructed and placed in service without a scrubber in 1983.