5. Potential Impacts of New Source Review Actions

Background

On November 3, 1999, the U.S. Department of Justice, on behalf of the U.S. Environmental Protection Agency (EPA), filed lawsuits against seven electric utility companies in the Midwest and South, charging that 17 of the companies' power plants had illegally released significant amounts of pollutants for two decades.[20] At the same time, the EPA issued an administrative order against the Tennessee Valley Authority (TVA), charging the Federal agency with similar violations at another seven power plants. In addition to the lawsuits and administrative order, the EPA issued notices of violation, naming an additional eight plants owned by other utilities as sites of similar violations of the Clean Air Act (Table 19).

Passed in 1970, the Clean Air Act is the comprehensive Federal law that regulates air emissions from area, mobile, and stationary sources. Among its many provisions is the explicit authorization for the EPA to establish National Ambient Air Quality Standards (NAAQS) in order to protect public health and the environment. The goal of the Act was to achieve the NAAQS by 1975, working in concert with the States through State Implementation Plans (SIPs).

The Clean Air Act was amended in 1977, primarily to set new dates for meeting attainment standards. At the same time, Congress eliminated existing facilities from many of its requirements, exempting them from immediate actions to add pollution control equipment unless they underwent major modifications. "Major modifications" would trigger New Source Review (NSR) standards, and the utilities would, in that event, be required to obtain a permit for Prevention of Significant Deterioration (PSD), which would be granted only if the plants used "best available control technology." Failure to obtain the permit under the conditions specified would leave the utilities liable to legal action and civil penalties.[21]

The dispute in the lawsuits filed for the EPA in November 1999 centers around whether certain modifications or capital improvements performed at the plants named in the action were "major"—specifically, whether the actions were aimed at increasing capacity, regaining lost capacity, or extending the life of the units. Correlatively, the EPA was also concerned with any modifications that would have the effect of increasing emissions.[22] The utilities responded by claiming that the modifications were "routine," undertaken as an integral part of maintaining standard operations at the plants, and thus could not trigger the NSR standards, which contain an explicit exemption for "routine maintenance, repair and replacement."[23] EPA's notice of violations stated that, in some instances, the modifications in question cost tens of millions of dollars and took years to complete. The utilities, however, referenced original plant capitalization costs that in some cases reached $500 million.[24]

Current Status

To date only one of the original cases has been resolved, and settlements have been reached with two other companies accused of similar violations. On February 29, 2000, the U.S. Department of Justice and the EPA jointly announced the settlement of a major Clean Air Act enforcement action against the Tampa Electric Company (TECO). The settlement followed months of negotiations that involved the utility, the two Federal agencies, the Florida Department of Environmental Protection, and the Florida Public Service Commission. The six other utilities and the TVA indicated they would defend themselves against the charges.

[20] Named in the lawsuits were American Electric Power (AEP), Cinergy, FirstEnergy, Illinois Power, Southern Indiana Gas & Electric Company, Southern Company, and Tampa Electric Company. U.S. Department of Justice, "U.S. Sues Electric Utilities in Unprecedented Action To Enforce the Clean Air Act," Press Release No. 524 (November 3, 1999).

[21] For the full text of the Clean Air Act (42 U.S.C. s/s 7401 et seq. (1970)), see U.S. Environmental Protection Agency, web site www.epa.gov/oar/caa/contents.html. Section 109 establishes the NAAQS, Part C sets forth the requirements for the prevention of significant deterioration, Parts C and D define modifications, Section 165 defines major emitting facilities, and Section 113(b)(2) prescribes civil penalties.

[22] Section 111(a) of the Clean Air Act, 42 U.S.C. § 7411(a).

[23] 40 CFR Section 52.21(b) (2) (iii) (a). For an analysis of utility maintenance strategies, see, J.L. Golden, Tennessee Valley Authority, "Routine Maintenance of Electric Generating Stations."

[24] For example, Unit 6 at the Conesville plant, a 444-megawatt unit, was completed in 1978 at an estimated real capital cost of $197 million. See M. McCabe, *An Empirical Analysis of Measurement Errors: Power Plant Construction Costs.* Master's thesis, Massachusetts Institute of Technology (Cambridge, MA, June 1986), Table 1, p. 15.

Table 19. Plants Named in the November 1999 New Source Review Litigation

State and Plant Name	Year of First Commercial Operation	Coal-Fired Capacity (Megawatts)
Alabama		
James H Miller Jr	1978	2,686
EC Gaston	1960	1,884
Barry	1954	1,634
Widows Creek	1952	1,610
Gorgas	1951	1,302
Colbert	1955	1,179
Greene County	1965	255
Florida		
Big Bend	1970	1,683
F J Gannon	1957	1,171
Crist	1959	1,019
Georgia		
Scherer	1982	3,352
Bowen	1971	3,187
Kraft	1958	217
Illinois		
Baldwin	1970	1,751
Indiana		
Cayuga	1970	995
Tanners Creek	1951	980
Wabash River	1953	753
R Gallagher	1958	560
F B Culley	1955	388
Kentucky		
Paradise	1963	2,159
Mississippi		
Jack Watson	1968	774
Ohio		
W H Sammis	1959	2,220
Conesville	1957	1,925
Cardinal	1967	1,800
Muskingum River	1953	1,365
Walter Beckjord	1952	1,118
Tennessee		
Cumberland	1973	2,448
Bull Run	1967	879
Allen	1959	744
John Sevier	1955	704
West Virginia		
Mitchell	1971	1,600
Phil Sporn	1950	1,020

Sources: Energy Information Administration, Form EIA-860A, "Annual Electric Generator Report" (1999); and U.S. Environmental Protection Agency, "A Summary of the Targeted Utilities . . .," Headquarters Press Release (November 3, 1999).

EPA's Notice of Violation against TECO stated that modifications undertaken as early as 1979 violated the Clean Air Act. Citing several specific instances at the Gannon plant, EPA said that replacing the furnace floor in 1996, the cyclone burners in 1994, and the second radiant superheater in 1992 constituted major modifications at Gannon. Similarly, the replacement of steam drum internals in both 1991 and 1994 as well as a high-temperature reheater replacement and a waterwall addition in 1994 without simultaneously installing pollution control equipment constituted violations at Big Bend.[25] EPA argued that the law provided for penalties of roughly $9 million per year, per violation, which, for just the violations specifically mentioned, would indicate a civil penalty in excess of $300 million.

Under the terms of a Consent Decree, TECO admitted to no violation of the Clean Air Act but agreed to undertake major efforts to bring its two large coal-fired plants into compliance with the standards promulgated by EPA. The entire Gannon facility, it was agreed, will be repowered to burn natural gas by January 2004. TECO also agreed to improve the use and operation of the scrubbers in use at Big Bend, and to install new combustion controls at Big Bend to reduce NO_x emissions starting in 2002. Major NO_x reductions must be shown at Big Bend by 2007, or TECO may have to repower or retire the units. TECO was forced to surrender its allocation "credits," which it received under Phase I of the SO_2 reduction program in 1995, and to pay a civil penalty of $3.5 million. TECO also agreed to contribute up to $2 million to study nitrogen deposition in Tampa Bay.[26]

In November 2000, the EPA reached a similar agreement with Dominion Virginia Power regarding three of its coal-fired plants. Although Virginia Power was not named in the November 1999 litigation, the EPA had served a Notice of Violation to the utility in June 2000 for Clean Air Act violations at its Mt. Storm power plant in West Virginia. Under the agreement, Virginia Power agreed to install scrubbers at Mt. Storm units 1 and 2 and to add SCR equipment to all three units at the plant. The utility also agreed to install scrubbers for two units and SCR equipment for three units at its Chesterfield plant and to install SCR equipment on two units at its Chesapeake plant. Virginia Power acceded to a civil penalty of $5.3 million to resolve issues at Mt. Storm and agreed to

[25]U.S. Environmental Protection Agency, Notice of Violation, EPA-CAA-2000-04-0007.

[26]Consent Decree, Civil Action No. 99-2524 CIV-T-23F.

provide $13.9 million for additional environmental projects, as yet unspecified. Like TECO, Virginia Power agreed to retire a portion of its allowances currently authorized by the Acid Rain program, beginning in 2012.[27]

In December 2000 it was announced that a tentative agreement had also been reached with Cinergy Corporation. Under the terms of the agreement, which must be finalized by the court, Cinergy would shut down or repower with natural gas approximately 600 megawatts of coal-fired generating capacity in Indiana and Ohio between 2004 and 2006; install new scrubbers on four coal-fired units in Indiana between 2008 and 2013; begin operating already-installed SCR units on a year-round basis for two coal-fired plants beginning in 2004; and meet a reduced system-wide NO_x cap by 2008. It was estimated that these actions would cost the company approximately $1.37 billion, making it the largest of the three settlements announced to date. In addition, the company agreed to "retire" 50,000 tons of SO_2 allowances between 2001 and 2005 and reduce its SO_2 cap by 35 percent in 2013. Finally, the company agreed to pay an $8.5 million fine, and to spend $21.5 million on additional environmental cleanup projects over the next 5 years.[28]

The outcome of the other pending lawsuits and regulatory actions is not known at this time. EIA takes no position on how these actions will or should be resolved; however, if the result is that a large number of power plants will be required to add state-of-the-art emissions control equipment in the near future, it could have an impact on the analyses discussed in Chapters 3 and 4 of this report.

Analysis Requested

In light of the developments discussed above, the Subcommittee asked that EIA study the potential impacts of two scenarios with different assumptions about the outcome of the ongoing legal and regulatory actions (see letter of September 25, 2000, in Appendix J). In the first scenario, the Subcommittee asked EIA to assume that the owners of each of the 32 plants named in the NSR litigation must either install best available control technology, convert their coal-fired units to some other fuel source, or retire those units by 2005. SO_2 targets would be reduced by amounts equal to the amount of allowances that would have been earned if the utilities had installed scrubbers at the outset of Phase I of the SO_2 trading program, modeling a "surrender" of allowances as in the TECO settlement. In a second scenario, the Subcommittee asked EIA to assume that all coal-fired plants in the power generation industry would be required to add state-of-the-art emissions control technology, switch to other fuel sources, or retire by 2010.

Four cases were prepared for the analysis described in this chapter:

- Case 1, the *NSR 32 case*, includes all the assumptions of the reference case described in Chapter 2, plus the assumption that each of the 32 coal plants named in the lawsuits by EPA would be required to add FGD equipment to reduce SO_2 and SCR equipment to reduce NO_x by 2005 in order to continue operating. In addition it is assumed that these plants would be required, as was TECO, to give up a portion of the allowances allocated to them in the existing SO_2 program. Although it remains unclear how the cases will be resolved, this analysis case assumes that their basic allowance allocations would be reduced by half, or 600,000 tons.

- Case 2, the *NSR All case*, again includes all the assumptions of the reference case described in Chapter 2, plus the assumption that all coal plants larger than 25 megawatts would be required to add FGD and SCR equipment by 2010 in order to continue operating. As in the NSR 32 case, it is assumed that the owners of the 32 plants named in EPA lawsuits would have to make their decisions by 2005. In addition, it is assumed that when compliance decisions are made in order to meet the summer season NO_x caps in 2004, a decision will also be made about adding NO_x and SO_2 controls, leading to the early addition of control equipment in this case.

- Case 3, the *integrated NSR 32 case*, combines the assumptions of the NSR 32 case with the emission caps assumed in the integrated 1990-7% 2005 case described in Chapter 2. In other words, it is assumed that power sector NO_x and SO_2 emissions would have to be reduced by 75 percent below their 1997 level by 2005, and CO_2 emissions would have to be reduced to their 1990 level by 2005 and further to 7 percent below their 1990 level on average over the 2008 to 2012 period.

- Case 4, the *integrated NSR All case*, combines the assumptions of the NSR All case with the emissions caps assumed in the integrated 1990-7% 2005 case described in Chapter 2.

[27]"Dominion Virginia Power Reaches Major Agreement with EPA," Electric News Release (November 15, 2000), web site www.dom.com/news/elec2000/pr1115.html.

[28]"Cinergy, EPA, Other Parties Reach Agreement on Power Plant Lawsuit," Cinergy Press Release, web site http://biz.yahoo.com/bw/001221/oh_cinergy_2.html; "Cinergy Agrees to Pay $1.4 Billion to Settle Federal Pollution Lawsuit," Wall Street Journal On-Line, web site http://public.wsj.com/sn/y/SB977502597772054208.html.

In each of the NSR cases the National Energy Modeling System determines the most economical way to comply with the emissions reduction requirements, while at the same time determining whether each of the affected coal plants should be retrofitted with FGD and SCR equipment and continue operating or be retired. The model has the option to add the control equipment to each plant or replace it with one of the 31 new plant types represented. The model chooses the most economical of the 31 options when it decides to replace a plant. It can replace a coal plant with another coal plant, a gas plant, a renewable plant, etc. The option to convert an existing coal plant to burn natural gas is not explicitly represented, because using relatively expensive gas in a plant that is only about 33 percent efficient is generally not economical. The model represents the conversion of a coal plant to natural gas by building a new gas plant and retiring the coal plant.

Results

NSR Base Cases

Table 20 provides summary information comparing the projections in the NSR 32 and NSR All cases with those in the reference case discussed in earlier chapters. In terms of generation by fuel—coal, natural gas, and renewables—the projections in the NSR base cases are similar to those in the reference case, because the requirement to add emission control equipment to some or all existing coal plants does not change the relative economics of operating most of them. In other words, although adding scrubbers and SCR units can be expensive, the operating costs of most of the plants would continue to be competitive after they were retrofitted, and they would continue to be used as they otherwise would have been.

Some coal plants are projected to be retired rather than retrofitted with the required control equipment. For example, in the reference case, 10 gigawatts of coal-fired capacity is expected to be retired between 1999 and 2020. In the NSR 32 case, where retrofit decisions would have to be made for approximately 45 gigawatts of coal-fired capacity, an additional 4 gigawatts of coal-fired capacity is projected to be retired. The vast majority of the plants named in the EPA actions are expected to be retrofitted if it is required. The projections are different in the NSR All case, where retrofit decisions are required for all coal plants. In the NSR All case, 31 gigawatts of coal-fired capacity is projected to be retired by 2020—21 gigawatts more than in the reference case.

An important issue in the NSR All case is the type of capacity that would be built to replace retired coal

Table 20. NSR Reference Case Projections, 2000, 2010, and 2020

Analysis Case	NO_x Emissions (Million Tons)	SO_2 Emissions (Million Tons)	CO_2 Emissions (Million Metric Tons Carbon Equivalent)	Electricity Price (1999 Cents per Kilowatthour)	Coal-Fired Capacity Retired
			2000		
Reference	4.57	11.43	570	6.80	0
			2010		
Reference	4.20	9.70	686	5.86	9
NSR 32	3.78	9.10	689	6.01	13
NSR All	1.56	1.94	700	6.11	31
			2020		
Reference	4.37	8.95	776	6.00	10
NSR 32	3.90	8.35	777	5.86	14
NSR All	1.62	1.90	784	5.96	31
Analysis Case	**SO_2 Scrubbers Added (Gigawatts)**	**SNCR Added (Gigawatts)**	**SCR Added (Gigawatts)**	**SO_2 Allowance Price (1999 Dollars per Ton)**	**CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)**
			2000		
Reference	0	0	0	156	0
			2010		
Reference	11	29	86	170	0
NSR 32	40	27	93	137	0
NSR All	195	19	276	0	0
			2020		
Reference	15	39	90	246	0
NSR 32	40	32	99	162	0
NSR All	195	19	276	0	0

NA = not applicable. SNCR - selective noncatalytic reduction. SCR - selective catalytic reduction.
Source: National Energy Modeling System, runs MCBASE.D121300A, MC_NSR.D121900A, and NSR_ALL.D121900A.

plants. As discussed in Chapter 3, in the reference case the vast majority of new capacity added—more than 90 percent—is expected to be fueled by natural gas. In that case, however, only a small amount of coal capacity is expected to be retired, and much of the new capacity added is expected to be built to operate in an intermediate load fashion, rather than being built to operate at full load for all hours of the year. New natural gas plants are the most economical option when this intermediate load capacity is needed. In the NSR All case, the retirement of 31 gigawatts of coal capacity is expected to lead to the need for new capacity to operate in a baseload fashion, at full load for most hours of the year. For this type of use, new coal plants—all of which are expected to meet new source emission standards—are projected to be competitive with natural gas plants in many parts of the country. As a result, most of the 31 gigawatts of coal capacity retired in the NSR All case is projected to be replaced with new coal plants. Natural gas plants still are expected to dominate capacity additions—386 gigawatts of 430 gigawatts of capacity added between 1999 and 2020 (90 percent of the total)—but new coal plants are projected to play a bigger role than in the reference case.

Relative to the reference case, the most significant changes in the NSR 32 and NSR All cases are in the projections of power sector NO_x and SO_2 emissions. In both cases, the requirement that coal plants add emissions control equipment to continue operating leads to significant reductions in NO_x and SO_2 emissions relative to the reference case—particularly in the NSR All case. For example, in the NSR All case NO_x emissions are projected to be 1.6 million tons in 2010, just over one-third the level expected in the reference case. The change is even more dramatic for SO_2 emissions, which are projected to be 1.9 million tons in 2010, about 20 percent of the level expected in the reference case. Because the NO_x and SO_2 emission levels in the NSR All case are well below the limits required by the summer season NO_x cap or the SO_2 allowance program established in the Clean Air Act Amendments of 1990, the allowance prices are projected to fall to zero.

The impact on electricity prices is projected to be quite small in the NSR base cases. As noted in the discussion of the NO_x and SO_2 cap cases in Chapter 3, because the costs of adding emissions controls generally do not increase the operating costs of the plants setting the market price for power, the average price of electricity is not expected to increase by much. The price impact is also reduced as a result of the assumption that plants will be forced to add the controls through "command and control" type regulation rather than through a cap and trade program, which would be expected to lead to higher NO_x and SO_2 allowance prices.

Although the price impacts are expected to be small, the power companies required to add control equipment would incur significant costs, particularly in the NSR All case. Between 1999 and 2020, operators of coal-fired power plants are projected to spend \$58 billion to add scrubbers to remove SO_2 and \$15 billion to add SCR NO_x emission control equipment.

Integrated Cases

Table 21 provides summary information comparing the projections in the integrated NSR 32 and integrated NSR All cases with those in the integrated 1990-7% 2005 case discussed in earlier chapters. Again, the projections for generation by fuel—coal, gas, and renewables—are similar among the three cases. The limit on CO_2 emissions in each of these cases is projected to lead to a rapid shift from coal to natural gas and, to a lesser extent, renewable fuels for electricity generation. For example, coal-fired generation in the reference case is projected to be 2,284 billion kilowatthours in 2010, but in these cases it is projected to range between 1,031 and 1,135 billion kilowatthours, roughly 50 percent below the reference case projection. Conversely, natural gas generation in 2010 is projected to be 1,123 billion kilowatthours in the reference case but roughly 69 to 77 percent higher, between 1,839 and 1,988 billion kilowatthours, in the NSR integrated cases.

The major differences among these cases are expected to be in NO_x and SO_2 emissions allowance prices, particularly in the NSR All case. For example, in the integrated 1990-7% 2005 case NO_x emissions in 2010 are projected to be 1.30 million tons, whereas they are projected to be 0.8 million tons in the integrated NSR All case. Similarly, SO_2 emissions are projected to be 3.9 million tons in 2010 in the integrated 1990-7% 2005 case but 1.0 million tons in the integrated NSR All case.

NO_x and SO_2 allowance fees are projected to be lower in the integrated NSR 32 and integrated NSR All cases than they are in the integrated 1990-7% 2005 case, because the requirement for coal plants that continue operating to add emissions control equipment reduces the need for other plant operators to take action to reduce their emissions. In the integrated NSR All case, both the NO_x and SO_2 allowance prices are projected to fall to zero by 2010 and stay there through the rest of the forecast, because the emission targets are assumed to remain at their 2008 levels through 2020.

Electricity prices in the three integrated cases are expected to be similar. The projections for 2010 range between 8.1 cents per kilowatthour and 8.4 cents per kilowatthour, between 37 and 42 percent above the reference case projection. The lower level of coal-fired electricity generation expected in the integrated NSR All case (because more coal plants are projected to be retired) leads to greater dependence on new natural gas plants, which in turn leads to higher projected natural gas prices—\$4.48 in 2020 in the integrated NSR All case versus \$4.30 in the integrated 1990-7% 2005 case.

Table 21. Integrated NSR Case Projections, 2000, 2010, and 2020

Analysis Case	Coal-Fired Generation (Billion Kilowatthours)	Gas-Fired Generation (Billion Kilowatthours)	NO_x Emissions (Million Tons)	SO_2 Emissions (Million Tons)	CO_2 Emissions (Million Metric Tons Carbon Equivalent)	Electricity Price (1999 Cents per Kilowatthour)
2000						
Integrated 1990-7% 2005 . .	1,943	599	4.6	11.4	570	6.7
2010						
Integrated 1990-7% 2005 . .	1,135	1,839	1.3	3.9	443	8.4
Integrated NSR 32.	1,086	1,903	1.3	3.9	438	8.4
Integrated NSR All.	1,031	1,988	0.8	1.0	442	8.1
2020						
Integrated 1990-7% 2005 . .	852	2,774	1.1	3.3	440	7.8
Integrated NSR 32.	869	2,755	1.1	3.3	439	7.7
Integrated NSR All.	802	2,856	0.8	0.7	442	7.8

Analysis Case	Coal-Fired Capacity Retired	SO_2 Scrubbers Added (Gigawatts)	SNCR Added (Gigawatts)	SCR Added (Gigawatts)	SO_2 Allowance Price (1999 Dollars per Ton)	CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)
2000						
Integrated 1990-7% 2005 . .	0	0	0	0	150	0
2010						
Integrated 1990-7% 2005 . .	47	10	49	147	226	134
Integrated NSR 32.	74	21	39	134	119	132
Integrated NSR All.	133	103	34	232	0	92
2020						
Integrated 1990-7% 2005 . .	79	17	49	147	99	130
Integrated NSR 32.	94	21	39	134	86	122
Integrated NSR All.	134	103	34	232	0	112

SNCR - selective noncatalytic reduction. SCR - selective catalytic reduction.
Source: National Energy Modeling System, runs FDP7B05.D121300B, FDP_N32.D121900A, and FDP_ALL.D121900A.

Summary

Requiring some or all coal-fired power plants to add equipment to reduce NO_x and SO_2 emissions to continue operating would have a significant impact on NO_x and SO_2 emissions and their respective allowance prices. If the 32 plants currently under suit by the Department of Justice on behalf of the EPA are required to be retrofitted with control equipment to continue operating, as assumed in the NSR 32 case, it is estimated that the SO_2 allowance price in 2010 would be cut by 19 percent relative to the projection in the reference case, from $170 to $137 per ton. Total SO_2 emissions are expected to be 0.6 million tons below the reference case level, because it is assumed that the plants would surrender approximately half their allowances under the terms of an agreement to end the suit.

Similar behavior is expected in the NO_x allowance market. The price impact of requiring the 32 plants to add control equipment is projected to be small. As discussed in Chapter 3, most of the control equipment is expected to be added to plants that do not set the market prices for power, and thus the costs would not be fully passed on to consumers.

The projected impacts on NO_x and SO_2 emissions and allowance prices are even larger in the NSR All case, which assumes that all coal-fired power plants must be retrofitted with control technology if they are to continue operating after 2010. In this case, both NO_x and SO_2 allowance prices are expected to fall to zero, because when new emission control equipment is added to all operating coal plants, NO_x and SO_2 emissions are projected to be well under established emission caps. For example, in the NSR All case, SO_2 emissions in 2010 are projected to be 1.9 million tons, well under the CAAA90 cap of 8.95 million tons.

A large number of coal plants—31 gigawatts (10 percent of existing capacity)—are expected to be retired in the NSR All case, because adding emission control equipment to them would not be economical. When those plants are retired, however, there would be insufficient baseload capacity (plants intended to run almost continuously) if they were not replaced. The vast majority of the plants retired are projected to be replaced by new coal plants that would comply with new source performance standards. As a result, projected CO_2 emissions in the NSR All case are virtually unchanged from those in the reference case. As in the NSR 32 case, electricity prices in the NSR All case are expected to be only slightly above those projected in the reference case. Power plant owners are projected to spend roughly $15 billion on SCR NO_x controls and $58 billion on SO_2 controls, reducing the profitability of the plants but not making them uneconomical.

When the assumptions in the NSR 32 and NSR All cases are combined with those used in the integrated 1990-7% 2005 case described in Chapter 2, the results are similar. Comparing the results in the integrated 1990-7% 2005, integrated NSR 32, and integrated NSR All cases shows that, to meet the emissions targets specified by the Subcommittee, the power sector is projected to reduce its use of coal dramatically and to increase its use of natural gas and, to a lesser extent, renewables.

The requirement that emission control equipment must be added to coal-fired plants if they are to continue operating in the integrated NSR All case is projected to lead to more coal plant retirements than projected in the integrated 1990-7% 2000 or integrated NSR 32 case, leading in turn to a lower CO_2 allowance fee in the integrated NSR All case. It is also projected to lead to even greater dependence on natural gas and, as a result, higher natural gas prices. The projected electricity prices are similar to those in the integrated 1990-7% 2005 case. This analysis suggests that efforts to reduce NO_x and SO_2 emissions at existing coal-fired power plants would make a portion of the plants uneconomical, but the majority would continue operating. Additional effort would be needed to substantially reduce power plant CO_2 emissions.

The analysis in this chapter assumes that affected coal-fired plants would make compliance decisions according to the schedule specified by the Subcommittee. The Subcommittee requested that EIA assume that the 32 plants named in the Justice Department suit would have to be retired or retrofitted with best available control technology by 2005, and that all other coal-fired plants would need to follow suit by 2010. In fact, it is likely that the terms of any settlements with the owners of the affected plants will vary from this strict timetable. The three settlements reached to date allow the companies to take action on a schedule that is somewhat less restrictive than the assumptions made in this analysis. To the extent that the owners of coal-fired plants are required to take the actions assumed in this analysis on a more or less restrictive timetable than EIA has assumed, the cost impacts could also be more or less severe. In addition, if all affected plants were forced to install the required equipment in either 2005 or 2010, it is possible that short-term bottlenecks in acquiring the needed labor and materials could arise, potentially making the cost to the industry higher than indicated by the analysis in this chapter.