Cost Analysis for Compliance with EPA's Regional NOx Emissions Reductions for Fossil-Fired Power Generation

Dennis Smith
U.S. Department of Energy, Federal Energy Technology Center, Pittsburgh PA

Alfred Mann
Parsons Project Services

Jon Ward and **Massood Ramezan**
Science Applications International Corporation

ABSTRACT

To achieve a more stringent ambient-air ozone standard promulgated in 1997, the U.S. EPA has established summer NOx emissions limits for fossil-fired electric power generating units in the Ozone Transport Rulemaking region, consisting of 22 eastern and midwestern states and the District of Columbia. These jurisdictions are required to submit State Implementation Plans by September 1999 in response to EPA's rule, with compliance required by 2007. There are 1757 affected units in this region. In the present study, projected state-by-state growth rates for power production are used to estimate power production and NOx emissions by unit in the year 2007. NOx emissions reductions expected by January 1, 2000 due to Title IV compliance are estimated, leaving a substantial balance of emissions reductions to be achieved by post-combustion NOx control. Cost estimates are developed for achieving these remaining reductions.

INTRODUCTION

The Clean Air Act Amendments of 1990 (CAAA), administered by the U.S. Environmental Protection Agency (EPA), require reductions in ground-level ozone and its precursors, including nitrogen oxides (NOx). Title IV, being implemented in two phases, addresses acidic deposition and establishes point-source NOx emission limits in terms of lb/million Btu of fuel fired. Table 1 gives the NOx emissions limits for Title IV. Title IV standards can generally be met by combustion modifications, whereas Title I limitations will require the use of advanced NOx control technologies.

Ozone Regulatory Requirements - Title I

Title I sets standards for control of six criteria pollutants, including ozone. Reviewing these standards every five years is mandated. Ground-level ozone is a major ingredient of smog. Since NOx is a major ozone precursor, it is necessary to control NOx to comply with ambient ozone standards. Effective July 16, 1997, the National Ambient Air Quality Standard (NAAQS) for ozone is 0.08 ppm (8-hour average). At this level, many large- and medium-sized urban areas are classified as being in nonattainment, and many power plants are situated within these nonattainment areas. Nonattainment of ozone standards results not only from NOx emissions in a given locality but also from significant amounts of NOx transported by winds over a wide geographical area.

meet Title IV and SCR and/or SNCR accomplish the final reduction required to meet Title I. Therefore, no further consideration was given to those alternative combustion modification technologies in this study.

ECONOMICS METHODOLOGY

Budgetary economics were calculated for the selected NOx control strategies, using the ECONMOD computer program developed by FETC [5], which incorporates the methodology for electric power generation costs established by the Electric Power Research Institute (EPRI) [6]. In the present study, costs are reported on a 1997 constant-dollar basis, and are based on the following financial assumptions: 50% debt at 8.5% return, 15% preferred stock at 7.0% return, and 35% common stock at 7.5% return. For a 10-year project life, the corresponding constant-dollar capital charge factor is 0.1557. For a 15-year project life the capital charge factor would be 0.1226, and for a 20-year project life it would be 0.1065.

APPROACH OF THIS STUDY

The boiler population affected by the SIP Call consists of a total of 1757 fossil-fired power generating units, as identified in a database developed by EPA. A logical sequence of NOx removal processes was assumed in the present study, using SCR and/or SNCR to achieve the required degree of emissions reduction. The less expensive SNCR would be used first, followed by the more expensive SCR. It was assumed that, at the time the proposed emissions controls are implemented in May 2003, NOx emissions will have been reduced by means of combustion modification to meet Title IV requirements, and that post-combustion control technologies would be used to achieve the final, more stringent requirements under Title I. For either SNCR or SCR (or their combination), a maximum NH_3 slip level of 3 ppm was set.

Rather than assess each unit individually, a matrix of representative units was defined and evaluated. Costs of installing NOx control technologies were estimated for the representative units. The actual database units were categorized and assigned to this matrix based on common characteristics, namely plant capacity, fuel type, and NOx level after Title IV controls. To calculate total compliance costs, the representative units were used as proxies for the actual units. Total costs ($/ton) for each unit and technology option were estimated based on age of the power plant, NOx removal percentage, and projected capacity factor. Based on these cost estimates, the least expensive options were progressively implemented until total NOx removal met the seasonal target of 544,000 tons.

Operation of SNCR and/or SCR only during the five-month summertime ozone season was assumed. During the remainder of the year, there would be no consumption of NH_3. Capital charges, of course, would continue throughout the year whether or not the SNCR/SCR units are operated. Emissions trading was incorporated into the analysis, assuming that any affected electricity generating unit could trade emission allowances with any other affected electricity generating unit without geographic limitations within the SIP Call area. No trading with industrial or other sources was considered. Allowing generating units to over-clean in one ozone season and bank those allowances for use or sale in a future season was not modeled. For SCR, retrofit difficulty was studied, using retrofit factors of 1.25 and 1.5.

Output growth beyond 2007 was not addressed. Since the average ozone-season capacity factor in 2007 for those units predicted to install SCR is 80-90%, it is reasonable to assume that their seasonal heat input, as well as NH_3 and catalyst consumption will not change much. Generating more power annually beyond 2007 without increasing total NOx emissions (which are capped) will require more NOx removal from existing units as well as tighter controls on new units. This will impose additional compliance costs not accounted for in this study. On the other hand, retiring existing units and replacing them with new, cleaner units will tend to drive down annual compliance costs.

ANALYSIS AND RESULTS

Costs at Representative Units

Since emissions trading and ideal market conditions were assumed, $/ton of NOx removed was the criterion for selecting units to which NOx control would be applied. The yearly charge for amortized capital (capital charge factor) increases as the life expectancy of the installed equipment decreases, all else being equal. For the base case analysis, a maximum power plant age of 60 years was assumed. Current industry trends show that through one or more refurbishments, many units can be operated for this duration or longer. In 2003, a unit first placed in service in 1960 would still have 17 years of life before reaching 60 years of age. A control technology would thus be expected to function for 17 years, until the unit's retirement.

This approach to life expectancy is most applicable to SCR installations, which are likely to remain useable even if the boiler is rebuilt as part of a refurbishment. Reburning and SNCR equipment may be largely lost during a boiler rebuild. Since this analysis shows SCR to be the dominant compliance technology, this method for estimating the life expectancy was not revisited.

Assignment of Costs to Database Units

<u>SCR on Coal-Fired Units</u>
Table 3 shows the SCR capital ($/kW) and levelized O&M costs ($/ton) assigned to each coal-fired database unit as a function of NOx inlet concentration and unit size. These costs are based on a 1.50 retrofit factor. For units less than 50 MWe, the 100 MWe representative unit may not be an accurate proxy. Capital costs for these smaller units were extrapolated. The price of anhydrous NH_3 is $300/ton, equivalent to $118/ton NOx removed.

<u>SCR on Oil- and Gas-Fired Units</u>
The exhaust gas from oil- and gas-fired boilers and combustion turbines has much less ash and typically less sulfur than that from coal-fired units. This allows the use of higher space velocities (smaller catalyst volumes) and catalysts that are less robust (and presumably somewhat cheaper). The following correlation for SCR on oil- and gas-fired boilers and new combined cycle units up to 500 MWe was used [3]:

$$\text{Capital cost (\$/kW)} = \$28.1 * [200/\text{MW}]^{0.35}$$

At 500 MWe, this correlation predicts a capital cost of $20/kW, which is also assumed to apply to capacities above 500 MWe. Operating costs include NH_3 consumption and catalyst replacement. NH_3 price is the same as for coal-fired units. Catalyst replacement costs are assumed to be 1/3 those of coal-fired units on a $/ton NOx removed basis, due mostly to smaller catalyst volumes and, to a lesser degree, cheaper catalyst. Costs for oil- and gas-fired units are included in Table 3.

SNCR on All Units

Based on published figures, a capital cost of $15/kW was used for all applications of SNCR.

Total Regional NOx Removal Costs

Base Case (NOx Removal: 80% for SCR, 25% for SNCR; SCR Retrofit Factor 1.5)

As stated above, the least expensive NOx control options were progressively implemented, unit-by-unit, until total NOx emissions met the seasonal target of 543,825 tons. This led to an upper limit or cut-off cost in $/ton. If NOx control at a unit would cost more than this cut-off cost, no controls would be installed at that unit. This analysis projected the cut-off to be about $2,810/ton. All units for which SCR could be implemented for less than $2,810/ton were assumed to apply SCR. To these were added SNCR installations at all additional units for which SNCR could be implemented for less than $2,810/ton. This method assumes that a power plant owner will remove as much NOx as possible (i.e., choose SCR) if the expected cost ($/ton) is below that of the most expensive NOx control systems being installed.

The Base Case results are summarized in Table 4. The average NOx removal cost for all affected units is $1,602/ton. Total NOx removed is 964,643 tons/season, which is within 0.7% of the 957,975 ton target projected by EPA, and gives a NOx emissions rate of about 537,100 tons/season. Only about 2% of NOx removal is from oil- or gas-fired units. Removal costs range from about $740-2,800/ton for SCR and about $1,140-2,800/ton for SNCR. Average costs are higher for SNCR because most units that would be low-cost SNCR sites are also low-cost SCR sites, and SCR is needed at these units to meet the 64% region-wide reduction target. The average capital charge factor for SCR units is 0.112, vs. 0.139 for SNCR, indicating that SCR is applied to a slightly younger segment of the boiler population (by an average of about 5 years).

Hybrids were found to be more expensive ($/ton) than SCR, and so were not chosen for any units. However, at many units, the cost difference was less than 20%, suggesting that more detailed unit-specific analyses may find hybrids to be preferred.

Case 2 (NOx Removal: 80% for SCR, 40% for SNCR; SCR Retrofit Factor 1.5)

The analysis was repeated assuming that SNCR could achieve 40% removal rather than 25%. This lowers the average $/ton cost for SNCR. Some of the NOx removal that was achieved in the Base Case by SCR is achieved by SNCR in Case 2. As shown in Table 5, the average cost drops to $1,526/ton. Marginal costs for additional NOx removal are about $2,650/ton (vs. about $2,800 in the Base Case). However, over 93% of the NOx removal is still achieved by SCR.

Case 3 (NOx Removal: 80% for SCR, 25% for SNCR; SCR Retrofit Factor 1.25)

The analysis was repeated assuming a retrofit factor of 1.25 for SCR installed on coal-fired units, rather than 1.5. No adjustment was made to oil- or gas-fired boilers or combustion turbines. Because two-thirds of the annual compliance cost is amortization of SCR capital costs, and 60-80% of that capital is affected by retrofit complexity, total compliance costs are more sensitive to SCR capital costs than to SNCR performance using the assumptions in this study. As shown in Table 6, the average cost drops to $1,443/ton. Marginal costs for additional NOx removal are about $2,500/ton.

Comparison with EPA's Cost Estimate

In its rulemaking announcement of September 24, 1998, EPA projected a compliance cost of $1,468/ton, which is within the range of $1,443-1,602/ton estimated in the present study. It is difficult to make direct comparisons between these results since details of the EPA calculations are not provided, such as assumptions regarding capital recovery rate, remaining life of power plants, capital and operating costs for both the SNCR and SCR processes, SCR catalyst life, etc.

CONCLUSIONS

To achieve the required reduction in NOx emissions in the SIP call area, it is projected that SCR would be selected for about 500 fossil-fired boilers, totaling about 180 GWe, and SNCR would be selected for about 200-300 units, totaling about 20-35 GWe. 98% of the NOx removed is from coal-fired units, and 93-98% of all NOx removal is achieved by SCR. The average levelized cost of compliance would be $1,400-1,600/ton of NOx removed (constant 1997 dollar basis), representing a total levelized cost of $1.4-1.6 billion/year. These results are in good agreement with EPA's projected costs of $1,468/ton of NOx removed and $1.4 billion/year.

REFERENCES

1. EPA, Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 FR 90, September 24, 1998.

2. Evaluation of NO_x Removal Technologies -- Volume 1, Selective Catalytic Reduction, Revision 2, Burns and Roe Services Corporation, Submitted to DOE/Federal Energy Technology Center, September 1994.

3. James E. Staudt (Andover Technology Partners), Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers, prepared for Northeast States for Coordinated Air Use Management (NESCAUM) and Mid-Atlantic Region Air Management Association (MARAMA), June 1998.

4. Institute of Clean Air Companies (ICAC), Letter to EPA, August 5, 1998.

5. Computer Program for the Economic Evaluation of Emissions Control Technologies, Burns and Roe Services Corporation, Submitted to DOE/Federal Energy Technology Center, January 1993.

6. TAG -- Technical Assessment Guide, Electric Power Research Institute, 1993.

Table 1. NOx emissions regulations for coal-fired boilers under Title IV.

Boiler Type	**NOx Emissions Limit, lb/million Btu**	
	Phase I	Phase II
Implementation Date	January 1, 1996	January 1, 2000
Group 1 Boilers		
Dry Bottom Wall-Fired	0.50	0.46
Tangentially Fired	0.45	0.40
Group 2 Boilers		
Wet Bottom Wall-Fired (>65 MWe)	NA	0.84
Cyclones (>155 MWe)	NA	0.86
Cell Burners	NA	0.68
Vertically Fired	NA	0.80
Fluidized Bed	NA	Exempt

NA = Not applicable

Table 2 - Summary of NOx emission data by state [1].

State	Electricity Growth Factor 1996-2007	2003 Projected Seasonal NOx Emissions after Title IV (Tons) [a]	SIP Call Final Budget (Tons)	NOx Emission Reduction Due to SIP Call (%)
Alabama	1.10	76,900	29,051	62
Connecticut	0.60	5,600	2,583	54
Delaware	1.27	5,800	3,523	39
DC	1.37	0	207	NA
Georgia	1.13	86,500	30,255	65
Illinois	1.08	119,300	32,045	73
Indiana	1.17	136,800	49,020	64
Kentucky	1.16	107,800	36,753	66
Maryland	1.35	32,600	14,807	55
Massachusetts	1.59	16,500	15,033	9
Michigan	1.13	86,600	28,165	67
Missouri	1.09	82,100	23,923	71
New Jersey	1.29	18,400	10,863	41
New York	1.05	39,200	30,273	23
North Carolina	1.21	84,800	31,394	63
Ohio	1.07	163,100	48,468	70
Pennsylvania	1.15	123,100	52,000	58
Rhode Island	0.47	1,100	1,118	-2
South Carolina	1.43	36,300	16,290	55
Tennessee	1.21	70,900	25,386	64
Virginia	1.32	40,900	18,258	55
West Virginia	1.05	115,500	26,439	77
Wisconsin	1.12	52,000	17,972	65
Total		1,501,800	543,825	64

[a] Rounded to nearest 100 tons

Table 3. Cost of NOx control on representative units using SCR.
NOx Removal = 80%; Retrofit Factor = 1.5

Capacity, MWe	Cost Type	NOx at SCR Inlet, lb/million Btu			
		> 0.60	0.40 - 0.60	> 0.25 - < 0.40	< 0.25
Coal-Fired Units					
> 400	Capital Cost, $/kW Levelized O&M Cost, $/ton	53 260	51 345	50 444	50 560
200 - 400	Capital Cost, $/kW Levelized O&M Cost, $/ton	65 260	61 345	60 444	60 560
50 - 200	Capital Cost, $/kW Levelized O&M Cost, $/ton	91 260	86 345	84 444	84 560
<50	Capital Cost, $/kW Levelized O&M Cost, $/ton	120 260	115 345	115 444	115 560
Oil- and Gas-Fired Units					
All	Capital Cost -- see text Levelized O&M Cost, $/ton	165	194	227	265

Table 4. Summary of total NOx control costs for Base Case.
NOx Removal = 80% for SCR, 25% for SNCR; SCR Retrofit Factor = 1.5

Tech-nology	Units Installed	MWe	NOx Removed, ton/season	Capital Cost, $million	Levelized Cost		
					Annual Capital Charge, $million	Annual O&M Cost, $million	Total Cost, $/ton NOx
SCR	518	183,854	934,470	10,303	1,154	340	1,599
SNCR	218	22,788	30,173	342	48	4	1,704
Total	736	206,642	964,643	10,645	1,202	344	1,602

Table 5. Summary of total NOx control costs for Case 2.
NOx Removal = 80% for SCR, 40% for SNCR; SCR Retrofit Factor = 1.5

Technology	Units Installed	MWe	NOx Removed, ton/season	Capital Cost, $million	Levelized Cost		
					Annual Capital Charge, $million	Annual O&M Cost, $million	Total Cost, $/ton NOx
SCR	477	171,798	892,670	9,474	1,060	324	1,550
SNCR	315	34,066	65,555	511	78	8	1,196
Total	792	206,864	958,225	9,985	1,138	332	1,526

Table 6. Summary of total NOx control costs for Case 3.
NOx Removal = 80% for SCR, 25% for SNCR; SCR Retrofit Factor = 1.25

Technology	Units Installed	MWe	NOx Removed, ton/season	Capital Cost, $million	Levelized Cost		
					Annual Capital Charge, $million	Annual O&M Cost, $million	Total Cost, $/ton NOx
SCR	528	181,429	936,226	8,898	999	343	1,433
SNCR	180	19,117	24,013	287	45	3	1,812
Total	708	200,546	960,239	9,185	1,042	346	1,443