region (see Figure 7 in Chapter V) would experience the highest growth in total consumption, from 43 million tons per year in 1979 to between 254 million tons under Option I to 275 million tons under current law (see Table 10). These figures delineate the upper and lower bounds of growth projected for that region. This pattern is consistent with the region's expected high growth in coal-fired capacity (see also Table 5 in Chapter V). The interregional differences in total coal consumption primarily reflect small variations in capacity use and "energy penalties" associated with scrubbing; thus, the current NSPS, in requiring scrubbers on all new coal-fired plants, show the highest forecast of total coal consumption. 8/

Although overall coal consumption is not significantly influenced by standards, the quantity of low-sulfur coal used is affected. For example, because Option I would have a more lenient control standard than the other options and would not mandate scrubbers, most utilities subject to this standard would choose to burn low-sulfur coal; in the year 2000, more than half of all coal consumed by utilities would be low-sulfur coal (see Table 10). 9/ At the opposite extreme, the current NSPS, by requiring scrubbers, would discourage consumption of low-sulfur coal where it was not locally produced. In the year 2000 under the current NSPS, only 40 percent of the coal consumed by utilities would have a low sulfur content, reflecting less eastern and midwestern consumption of low-sulfur coal than would occur under Option I. Options II and III, by permitting compliance with emissions floors, would also spur the consumption of low-sulfur coal, though to a lesser extent than Option I. Similarly, Option IV, by promoting emissions trading, would increase low-sulfur coal consumption, since that fuel could be used in both new and old facilities to achieve relatively inexpensive emissions reductions.

Coal Production. Where coal is produced and how production is affected by different emissions standards are other important questions. Regardless of which of the options examined here were chosen, the western states would experience the highest growth in coal production over the next two decades. The major reason for this is not so much the amount of

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8. The use of scrubbers requires power, which must be supplied by the utility. Thus, the greater amount of scrubbing employed, the more coal consumed to meet overall electricity demand. (See Appendix B on scrubber assumptions.)

9. For the purposes of this discussion, low-sulfur coal is assumed to produce less than 1.2 pounds sulfur dioxide per million BTUs.

TABLE 10. UTILITY COAL CONSUMPTION IN 1979 AND PROJECTED FOR THE YEAR 2000, BY REGION (In millions of tons per year)

Region	Baseline Consumption (1979) a/	Current Standards Total Consumption	Current Standards Percent Low-sulfur	Option I Total Consumption	Option I Percent Low-sulfur
East	208	290	41	291	48
East North Central	160	241	21	243	35
East South Central	72	88	21	90	28
West North Central	74	134	33	128	46
West South Central	43	275	49	254	79
West (Mountain and Pacific)	62	146	47	146	67
Total	619	1,174	40	1,152	51

(continued)

NOTE: Boundaries of regions displayed in Figure 7.

a/ Percent of total 1979 low-sulfur coal consumption is not available.

eastern and midwestern demand for western coal arising from each option, as it is the expected high growth in western coal-burning capacity. Beyond the West's high projected use of local coal supplies, the choice of emissions standards can, however, influence the West's share of the eastern markets. The Midwest, with its deposits of high- and moderate-sulfur-content coal, is the area most vulnerable to standards that encourage consumption of low-sulfur coal.

Continuation of the current standards, which, by design, should mitigate the economic advantage of low-sulfur coal as a means to control emissions, would result in relatively high production forecasts for the Midwest (a 92 percent growth in production by the year 2000) and the lowest projected eastward shipment of western coal (127 million tons). In contrast, Option I

TABLE 10. (Continued)

Option II		Option III		Option IV	
Total Consumption	Percent Low-sulfur	Total Consumption	Percent Low-sulfur	Total Consumption	Percent Low-sulfur
290	48	292	37	290	46
242	34	242	31	242	20
89	28	88	18	89	24
130	47	128	39	132	36
260	76	263	74	268	57
149	65	146	59	149	55
1,160	50	1,159	44	1,146	42

SOURCE: Baseline 1979 consumption from U.S. Department of Energy, Bituminous and Subbituminous Coal and Lignite Distribution, Calendar Year 1979 (April 21, 1980).

would encourage the use of low-sulfur coal; this choice would reduce the expected growth rate in midwestern coal production to 76 percent and raise the quantity of low-sulfur western coal shipped east to an annual 151 million tons by the year 2000 (see Table 11). (This amount would be higher were it not for the large quantity of low-sulfur coal available from Northern and Central Appalachian mines--see Table 12.)

Both western production and eastward shipment would rise as a result of policies that put a premium on coal with a sulfur content below 1.2 pounds sulfur dioxide per million BTUs--coal that, despite Central Appalachian reserves, is not abundant in the East. Thus, Option II would foster the eastward movement of large quantities (164 million tons in 2000) of western coal; such transported coal would help users to meet this option's floor of

0.8 pounds sulfur dioxide per million BTUs without scrubbing (see Table 10). As a result of lowering the floor to 0.6 pounds sulfur dioxide per million BTUs, as in Option III, however, the supply of coal usable without scrubbing would become limited primarily to that mined in the Rocky Mountain and Western Northern Great Plains regions. This would restrict the total eastward import of western coal to an annual 145 million tons in the year 2000. Furthermore, the limited availability of western coal that can meet the standard of Option III without scrubbing, plus the costs of transport, and the emissions floor requiring no further control would all tend to encourage the use of local high-sulfur coal in the Midwest. The result would lead to production levels in the Midwest similar to those encouraged by the current standards (see Table 11). 10/

Compared to the current standards, Option IV would increase western coal production but would not give rise to so high a demand for low-sulfur coal as the other alternatives (see Table 12), since medium-sulfur coal would often supplant high-sulfur coal. High-sulfur coal production in the Midwest would be lower than under the current standards but somewhat higher than under Option I. This small increase could be expected to result from greater use of existing plants with scrubbers and from emissions trading in some areas that allow a few plants to burn high-sulfur coal without scrubbers. (This latter situation might not be desirable, and an emissions ceiling for new sources could be used to prevent it; such a ceiling was not included in these estimates.)

Substitution of medium- for high-sulfur coal (not shown in the tables) also would be high under Option IV, since this approach would allow utilities to meet acceptable emissions limits at nominal expense; burning medium-sulfur fuel would remain appreciably cheaper than resorting to scrubbers. Use of low-sulfur coal, however, would remain the chief strategy to reduce emissions under Option IV, and demand for western coal for eastern utilities

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10. Because most midwestern coal is surface-mined and hence cheaper than most Appalachian coal, which is deep mined, some Appalachian coal production would be displaced by midwestern coal. This would allow midwestern coal production levels in Option III to remain as high as under current standards, even though more western coal actually would be shipped eastward. Without the very low emissions floor of Option III, however, the cost to eastern users of purchasing and scrubbing a midwestern coal would be higher than buying a low-sulfur coal from nearby Appalachia (coal that must be scrubbed even to meet very low emissions floor), and midwestern coal production levels would fall.

would rise to 149 million tons per year--higher than under the current standards but lower than all others except Option III.

Sensitivity to Flue Gas Desulfurization and Other Cost Assumptions. To whatever extent that the costs of flue gas desulfurization technology drop, the demand for low-sulfur coal would also fall. This effect would be particularly pronounced under any alternative standards that emphasize scrubbers or any similar sulfur dioxide control method. On the other hand, if the cost of using low-sulfur coal increased, scrubber capacity also would rise. For example, the amount of low-sulfur coal shipped east is affected by rail costs; if rail rates are assumed to rise 15 to 25 percent between 1985 and 1990 (as stated earlier, under modified assumptions for Option I), only 94.3 million tons of western coal would be shipped east in the year 2000. This is a reduction of almost 57 million tons from that originally predicted for the same alternative. The high rail rates would force eastern and midwestern coal users to turn to the higher-priced but nearer low-sulfur Appalachian coal and to use scrubbers, so that cheap local high- and medium-sulfur coals could be burnt while meeting a standard of 1.2 pounds sulfur dioxide per million BTUs. In this respect, increased rail costs alone would be responsible for greater shifts in coal production and distribution than would be the expected changes resulting from any of the emissions control alternatives considered.

CONCLUSIONS FROM THE ANALYSIS

The CBO projections suggest that alternative emissions standards for new electricity sources can yield nominally different levels of sulfur dioxide emissions at widely divergent costs. Adopting Option I--that is, reverting to the NSPS of 1971--would be the least effective in controlling new emissions, resulting in 22.8 million tons of sulfur dioxide from utilities by the year 2000. In comparison, the current NSPS are projected to achieve sulfur dioxide emissions levels 8 percent lower, but at an average cost of $2,411 for each ton of sulfur dioxide eliminated. The two alternatives with emissions floors, Options II and III, each would entail significantly lower capital costs than the current NSPS, but neither would be highly cost effective in reducing emissions. Option II would lower emissions by 3 percent from the previous NSPS at a cost of $1,929 per ton of sulfur dioxide removed, while Option III would lower emissions by 4 percent, but at a cost of $3,400 per ton. Finally, Option IV, with its emissions trading feature, would achieve the same quite high degree of emissions control as the current 1978 standards do, but at an average cost of only $550 for each ton of sulfur dioxide reduced beyond the levels forecast for Option I.

TABLE 11. REGIONAL COAL PRODUCTION FOR THE YEAR 2000 UNDER EACH ALTERNATIVE (In millions of tons per year and percent increase over base year)

Region	Base Year Production (1979)	Current Standards		Option I	
		Production	Percent Increase	Production	Percent Increase
Northern Appalachia	187	331	77	316	69
Central Appalachia	213	342	61	359	69
Southern Appalachia	24	21	-13	21	-13
Midwest	131	252	92	231	76
Central West	13	17	31	19	46
Gulf	26	119	358	82	215
Eastern Northern Great Plains	14	44	214	44	214
Western Northern Great Plains	104	383	268	409	293
Rocky Mountains	27	183	578	199	637
Southwest	25	142	468	131	424
Northwest and Alaska	5	33	560	32	540
Total	769	1,866	143	1,843	140
Total Western Coal Consumed by Eastern Utilities	22 a/	127	477	151	586

(continued)

a/ See U.S. Department of Energy, Bituminous Coal and Lignite Distribution, Calendar Years 1978 and 1979 (December 21, 1979 and April 21, 1980).

TABLE 11. (Continued)

Option II		Option III		Option IV	
Pro- duction	Percent Increase	Pro- duction	Percent Increase	Pro- duction	Percent Increase
312	67	302	61	314	68
350	64	356	67	354	66
20	-17	20	-17	20	-17
234	79	254	94	239	82
16	23	15	15	16	23
94	262	87	235	112	331
45	221	45	221	45	221
401	286	385	270	402	287
216	700	231	756	180	567
132	428	126	404	148	492
32	560	32	540	33	560
1,852	141	1,853	141	1,862	142
164	645	145	559	149	577

SOURCE: CBO/ICF analysis.

TABLE 12. ESTIMATED LOW SULFUR COAL PRODUCTION IN 2000, BY REGION (In millions of tons per year)

Region	Current NSPS	Option I	Option II	Option III	Option IV
Northern Appalachia	20.8	24.1	37.1	31.8	29.2
Central Appalachia	203.7	224.9	207.9	217.7	206.7
Southern Appalachia	3.4	3.4	2.9	2.9	3.4
Midwest	0.5	0.4	0.5	0	0.5
Central West	5.1	6.1	4.7	4.4	5.0
Gulf	None	None	None	None	None
Eastern Northern Great Plains	1.4	1.4	1.4	1.8	1.4
Western Northern Great Plains	214.0	268.0	265.4	247.0	245.3
Rocky Mountains	122.7	138.7	161.2	180.4	124.7
Southwest	79.7	84.3	85.3	77.5	82.4
Northwest/Alaska	21.4	21.4	21.4	21.4	21.4
Total	672.7	771.3	787.8	784.9	720.0

SOURCE: CBO/ICF analysis.

NOTE: Figures on base year production not available.

The low cost per ton of Option IV highlights two important points:

- Emissions from older sources not covered by any emissions standards will dominate national emissions through the year 2000 and beyond--hence the rather narrow margin within which emissions abatement projections fall; and

- The least costly control measures now available are those that involve substituting lower-sulfur coals at existing sources now using high-sulfur coals.

With regard to effects on the utilities' financial requirements, the results indicate that the current NSPS are the most capital-intensive choice; they also entail the highest annual costs because of fixed and variable charges associated with scrubbers. Options II and III, with their greater reliance on low-sulfur coal as a means to achieve emissions control, would result in lower capital requirements; they also involve generally lower annual costs, although utilities would remain vulnerable to fuel and transport cost escalations. Control levels equivalent to the current NSPS could be achieved by Option IV, and at a significantly lower cost; the burden of control would be more evenly distributed among new and older facilities.

In light of the current costs of control technology and the abundance of low-sulfur western coal, emissions standards for new sources can alter traditional patterns of coal supply and demand. In particular, limiting sulfur dioxide emissions without requiring scrubbers for all coal types, as under Option I, would tend to increase the market share that low-sulfur coal holds. That, in turn, could raise the volume of shipments of western coal to the Midwest and East, as eastern low-sulfur coal costs rise and supplies in certain instances shrink. Nothing short of a mandatory scrubbing, as under current standards, could slow--and only slow--this eastward penetration. Both Options II and III, by eliminating scrubbing for only some coals (those found mostly in the West), would also raise the amount of western coal shipped East. No matter what emissions standard are in force, midwestern and some eastern coal production would remain vulnerable to the lower cost and rapidly growing production of western coal. Mitigating circumstances that would help encourage coal production in the East, and in particular, the Midwest, are higher-than-expected rail rates over the next two decades and significantly lower costs than anticipated for flue gas desulfurization technology. The latter would entail technological breakthroughs or improvements now being studied but not yet foreseen.

Finally, the analysis points to some difficult choices for the Congress in assigning priorities, since minimizing sulfur dioxide emissions, utility costs, and losses in midwestern coal production cannot all be done simultaneously. To hold emissions to their lowest levels and protect midwestern coal production, the current standards are the best choice. If, however, reducing the capital burden on utilities is given equally high priority, then Option III--which lowers capital needs by roughly half, raises emissions only slightly, and yields relatively high midwestern production forecasts—becomes a more preferable choice. If both emissions control and cost are high priorities, but safeguards for midwestern coal production are not, then the best alternative is Option IV. Finally, if cost is the chief concern, then Options I and II, which would promote the use of low-sulfur coal though allowing greater emissions growth than the current standards, are the most suitable policy choices.

APPENDIXES

APPENDIX A. EFFECTS OF THE PSD PROGRAM

The CBO analysis of the Clean Air Act's potential influence on the electric utilities includes assumptions about the effects of "prevention of significant deterioration" (PSD) provisions. Though probably smaller than the effects of the new source performance standards, and difficult to quantify separately from them, the effects of the PSD provisions are still of interest. The following analysis reviews the estimated influence of the PSD program on emissions, power plant siting, and construction schedules. Only the effects of the PSD program on emission limits were included in the projections (see Appendix B), since other costs, such as administrative requirements, are believed to be insignificant.

EFFECT ON EMISSIONS LIMITS

In a recent study, the National Commission on Air Quality has concluded that the case-by-case "best available control technology" review process under the PSD program has often resulted in emission limitations stricter than would have been required by NSPS or state implementation plans. 1/ According to the commission, all PSD permits issued between April 1978 and November 1979 showed that nine out of 16 permits issued for power plants during that period contained control requirements significantly more stringent than the NSPS. These tighter requirements will lead to 20 percent reductions in sulfur dioxide emissions and 25 percent reductions in particulate emissions beyond levels allowed under the NSPS. (The means of compliance for these facilities is unknown, but it probably will often involve additional scrubbing or lower-sulfur fuel.) Because these control levels were established before 1979, however, much of their cost to the industry should be captured in the analyses in Chapter II.

Because the current NSPS require such a high degree of control, situations in which the PSD regulations result in significant additional emissions control should be rare. The exceptions concern possible requirements of up to 90 percent control on sulfur dioxide emissions for plants burning low-sulfur coal, rather than the requisite 70 percent. This situation

1. See National Commission on Air Quality, To Breathe Clean Air, Final Report (March 1981).

could occur in areas desiring to limit emissions further and protect air quality; examples may be Wyoming and New Mexico, which already require more than 70 percent control on some power plants firing low-sulfur coal. No evidence suggests, however, that BACT levels stricter than NSPS will be established with any frequency in the future for most regions.

EFFECTS ON POWER PLANT SITING

An important concern is whether the Clean Air Act imposes non-economic, institutional constraints on the construction of new generating capacity. Compliance with both PSD regulations and national ambient air quality standards can pose operational limitations on a power plant at a particular site. Such limitations can restrict how much capacity can be built in certain areas.

The EPA reports that both the 1971 and revised 1978 NSPS for utilities allow a 1,000-megawatt coal-fired boiler to operate in a Class II PSD area, assuming no appreciable background concentrations or other sources nearby, and relatively flat terrain. 2/ Under these conditions, one large plant complying with the 1971 NSPS would leave little if any 24-hour PSD increment (see Table 2 in Chapter II), while the same plant complying with the 1978 revised NSPS would consume approximately half of the 24-hour increment, usually the most limiting standard. Compliance with either emissions standard would not allow a facility of this size to be located either in or near a Class I area. Thus, in certain circumstances, such as where the terrain is mountainous, contains Class I areas, and other nearby sources, compliance with NSPS might not be sufficient to protect the Class II increments, and further emissions control or moving to another site might be necessary. If emissions control proved too costly, or if an alternate site were not available, the new plant would not be built.

Both the national commission and the National Academy of Sciences report that the major constraints on power plant siting from PSD regulations involve the presence of "complex" (mountainous) terrain and Class I areas near or surrounding the potential site. 3/ In the West, Class I areas

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2. Terrain that is not flat tends to confine and thus concentrate pollutant emissions.

3. See National Commission on Air Quality, To Breathe Clean Air, and National Academy of Siences, On Prevention of Significant Deterioration of Air Quality, National Academy Press (1981).

(National Parks and certain national monuments) represent the greatest potential constraint, at times perhaps limiting development within a 100-kilometer radius. In the East, Class II areas and the presence of other sources of pollutants pose the greatest potential for siting constraints. Both the commission and national academy also conclude that such constraints are specific to certain sites and are difficult to quantify generically; moreover, they point out that other legislation besides the Clean Air Act severely restricts development in many Class I areas, thus making it difficult to assign growth limitations in Class I areas to the Clean Air Act alone. Finally, alternative sites are usually available, thus allowing a plant to be built somewhere. Much less certain is the incremental cost of relocating a power plant early in its planning process.

Only two applications for PSD permits have been denied, both involving permits for coal-fired power plants near Class I areas. After submission of additional information, one was approved with minor modification. The other power plant eventually received a permit after adopting more stringent controls to reduce total sulfur dioxide emissions by 95 percent. The actual incremental cost of achieving this additional control is unknown.

EFFECTS ON CONSTRUCTION SCHEDULES AND RESULTING COSTS

Between 1970 and 1980, average power plant construction times increased from four to seven years. The reasons most often cited involve the numerous operating licenses and permits required by various laws enacted over the last decade. The Clean Air Act is responsible for one of the more complex permit processes, and thus it is a suspected contributor to protracted construction schedules.

The PSD regulations entail certain explicit and implicit time-consuming tasks. Strictly interpreted, the regulations can require one-year's air quality monitoring data for the permit application. Time is also taken up in developing permit submissions, probably six months. In addition, the reviewing agency is then allowed one year either to approve or reject the permit application. Thus, assuming the permit is approved, up to 30 months can elapse before construction begins.

In practice, the time necessary to obtain a PSD permit varies widely, but it is usually less than 30 months. Table A-1 shows the time spent in the various stages of obtaining a permit, based on a survey of PSD permits issued according to the requirements of the Clean Air Act's 1977 amendments. Before embarking on the early stages of the permit process, a utility

TABLE A.1 PROCESSING TIME SPENT FOR NEW SOURCES BEFORE AND DURING PSD REVIEW

Process Sequence	Median Number of Days	90th Percentile a/	95th Percentile a/
Initial Contact to Initial Submission	42	440	487
Initial to Final Submission	57	298	319
Final Submission to Permit Issue	157	323	328
Initial Submission to Permit Issue	271	463	528
Initial Contact to Permit Issue	333	612	634

SOURCE: See Dames and Moore, "An Investigation of Prevention of Significant Deterioration (PSD) and Emission Offset Permitting Processes," prepared for National Commission on Air Quality (Revised December 1980).

a/ Upper quartiles; 90 percent and 95 percent of permits were processed in these numbers of days or fewer.

applicant typically contacts the agency to determine whether monitoring is required, and if so, how much and what control requirements may be imposed. If the critical permit stages, including monitoring, are assumed to occur between initial contact and permit issuance, then it is clear that total processing time is usually completed within a year, although delays of up to two years can occur in rare instances.

The reasons for the relatively shortened time needed to obtain a permit compared to what theoretically can elapse probably involve the short median time an agency spends on reviewing a final permit and determining how much monitoring to require. The short processing time for final permits is evidenced in Table A-1 as usually consuming less than six months.

With regard to monitoring, the same study responsible for the data in the table found that reviewing agencies required actual on-site monitoring data for particulate matter and sulfur dioxide in only 17 and 15 percent of all cases, respectively. In the other instances, either monitoring was not required, or existing state and local data collected by public agencies were available and accepted.

With regard to the costs associated with increased lead times for construction, it is important to distinguish between time requirements that can be incorporated into the overall planning process and those that fall outside of this schedule, thus resulting in delay. Table A-1 indicates that the overall time required to obtain a PSD permit can cover one to two years but more commonly involves one. If the one year usually required to obtain a permit can be partially or totally absorbed within other planning requirements, such as selection of final design and equipment specifications prior to construction, then delay is reduced to less than one year.

Table A-2 presents estimates of project cost increases for a six month, 12-month, 18-month, and 24-month delay in construction start-up. These estimates include the costs associated with inflation as well as those associated with extended use of obsolete capacity (identified in the table as energy replacement), in this case, a 500-megawatt oil-fired plant.

TABLE A-2. ESTIMATED COSTS OF DELAYS IN CONSTRUCTION START-UP OF A NEW 500-MEGAWATT COAL-FIRED POWER PLANT (In millions of dollars)

	Six-Month Delay	12-Month Delay	18-Month Delay	24-Month Delay
Energy Replacement	4.3	8.6	13.0	17.4
Inflation	25.0	50.0	78.0	104.0
Total	29.3	58.6	91.0	121.4

SOURCE: Congressional Budget Office.

The average increase in normal project lead-time associated with the Clean Air Act is estimated to be six months, which translates into some \$29.3 million for the example given in Table A-2. This estimate assumes that approximately one year of permit preparation and review is necessary, of which half falls outside the normal planning schedule necessary for project start-up. Adding the costs of a full monitoring network for sulfur dioxide, nitrogen oxide, and particulate emissions, and necessary air quality analysis costs for developing a permit (a total cost of approximately \$140,000) results in a possible total cost increase of \$29.4 million for the example given. For comparison, CBO estimated that a change in the interest rate or weighted cost of capital from 10 to 11 percent could result in a total project cost increase of \$101 million.

APPENDIX B. ANALYTICAL ASSUMPTIONS AND METHODOLOGY

To arrive at forecasts of pollutant emissions, changes in capital and annual costs, and coal market effects, the CBO used a detailed linear programming model developed by ICF, Incorporated. The key assumptions, including scrubber costs, were supplied by CBO for use in the simulations. A review of the assumptions and methodology used follows.

DESCRIPTION OF ASSUMPTIONS

Table B.7, at the end of this appendix, defines the major assumptions used in the modeling effort. Tables B.1 through B.4 present the estimated costs used in the analysis of scrubbers for different coal types. These costs are based on a recent Tennessee Valley Authority study, Technical Review of Dry FGD Systems and Economic Evaluation of Spray Dryer FGD Systems (EPA-600/7-81-014) and the information contained in EPA Utility FGD Survey: October-December 1980, (EPA-600/7-81-021a). The costs of the basic units include all equipment and materials needed to transfer the flue gas from the boiler to the stack, as well as collection and disposal of sludge and fly ash residues. The estimates in the tables also reflect a small expected increase in the real costs of equipment and operation between 1980 and 1985, the starting point used for the simulations. Table B.5 displays estimated costs of upgrading particulate control equipment necessary when switching from high-sulfur to low-sulfur coal, as simulated for computation for Option IV.

The costs presented in these tables give rough approximations of the cost-penalty involved; only a case-by-case analysis of actual fuel-switching situations could provide an accurate estimate. Such information was not available for this report.

METHODOLOGY

The effects of the assumptions and alternative standards were estimated using the ICF Coal and Electric Utilities Model (ICF/CEUM). The model simulated key attributes of the coal and electric utility industries by year and by region. For the coal industry, forecasts were made of coal consumption by sector, production by mining method, supply prices, coal

TABLE B.1. CURRENT NSPS

Item	Variable					
	(Coal Type in Pounds SO_2 Per Million BTUs Consumed)					
Raw Coal	0.8	1.2	1.76	3.92	6.67	8.89
Delivered Coal	0.8	1.2	1.67	3.33	5.0	6.67
Coal to Scrubber	0.76	1.14	1.59	3.16	4.75	6.33
Annual Sulfur Dioxide Limit	0.24	0.36	0.5	0.5	0.67	0.89
	(Percent Pollutant Control)					
Design Control Efficiency	70	70	70	90	90	90
Actual Control Efficiency	68	68	69	84	86	86
Scrubber Type	Dry	Dry	Dry	Wet	Wet	Wet
	(Dollars per Kilowatt)					
Total Costs for SO_2 and Particulate Control	144	145	146	228	231	235
	(Mills per Kilowatt-Hour)					
Operation and Maintenance Costs--Fixed and Variable	2.15	2.39	2.68	3.9	4.37	4.8
	(Percent)					
Capacity Penalty	1.52	1.54	1.58	2.23	2.45	2.61
Energy Penalty	2.36	2.38	2.42	3.47	3.85	4.01

SOURCE: Congressional Budget Office

NOTES: All costs based on a 500-megawatt power plant generating 5,500 hours per year. Amortized capital costs not included; all O&M costs are first-year costs. Costs expressed in mid-1980 dollars.

TABLE B.2. OPTION I—EMISSIONS CAP OF 1.2 POUNDS OF SULFUR DIOXIDE PER MILLION BTUs OF FUEL CONSUMED

Item	Variable					
	(Coal Type in Pounds SO_2 Per Million BTUs Consumed)					
Raw Coal	0.8	1.2	1.76	3.92	6.67	8.89
Delivered Coal	0.8	1.2	1.67	3.33	5.0	6.67
Coal to Scrubber	0.76	1.14	1.59	3.16	4.75	6.33
Annual Sulfur Dioxide Limit	0.76	1.14	0.8	1.0	1.0	1.0
	(Percent Pollutant Control)					
Design Control Efficiency	0	0	Part a/	70	80	90
Actual Control Efficiency	0	0	50	68	79	84
Scrubber Type	NA	NA	Dry	Dry	Wet	Wet
	(Dollars per Kilowatt)					
Total Costs for SO_2 and Particulate Control	71	71	123	148	207	235
	(Mills per Kilowatt-Hour)					
Operation and Maintenance Costs--Fixed and Variable	0.1	0.1	1.77	3.64	4.2	4.8
	(Percent)					
Capacity Penalty	0	0	1.12	1.8	2.24	2.61
Energy Penalty	0	0	1.71	2.81	3.48	4.01

SOURCE: Congressional Budget Office

NOTES: All costs based on a 500-megawatt power plant generating 5,500 hours per year. Amortized capital costs not included; all O&M costs are first-year costs. Costs expressed in mid-1980 dollars.

a/ "Part" indicates 70 percent control of portion of flue gas.

TABLE B.3. OPTION II—ACHIEVE 70 PERCENT EMISSIONS CONTROL AND SET A 0.8 POUND FLOOR

Item	Variable					
	(Coal Type in Pounds SO_2 Per Million BTUs Consumed)					
Raw Coal	0.8	1.2	1.76	3.92	6.67	8.89
Delivered Coal	0.8	1.2	1.67	3.33	5.0	6.67
Coal to Scrubber	0.76	1.14	1.59	3.16	4.75	6.33
Annual Sulfur Dioxide Limit	0.76	0.62	0.64	1.0	1.0	1.0
	(Percent Pollutant Control)					
Design Control Efficiency	0	Part a/	Part a/	70	90	90
Actual Control Efficiency	0	50	60	68	80	84
Scrubber Type	NA	Dry	Dry	Dry	Wet	Wet
	(Dollars per Kilowatt)					
Total Costs for SO_2 and Particulate Control	71	119	134	148	231	235
	(Mills per Kilowatt-Hour)					
Operation and Maintenance Costs-- Fixed and Variable	0.1	1.32	2.15	3.64	4.22	4.8
	(Percent)					
Capacity Penalty	0	1.04	1.37	1.81	2.45	2.61
Energy Penalty	0	1.61	2.1	2.81	3.58	4.01

SOURCE: Congressional Budget Office

NOTES: All costs based on a 500-megawatt power plant generating 5,500 hours per year. Amortized capital costs not included; all O&M costs are first-year costs. Costs expressed in mid-1980 dollars.

a/ "Part" indicates 70 percent control of portion of flue gas.