TABLE B.4. OPTION III—ACHIEVE 90 PERCENT EMISSIONS CONTROL AND SET A 0.6 POUND FLOOR

Item	Variable					
	(Coal Type in Pounds SO_2 Per Million BTUs Consumed)					
Raw Coal	0.6	1.2	1.76	3.92	6.67	8.89
Delivered Coal	0.6	1.2	1.67	3.33	5.0	6.67
Coal to Scrubber	0.57	1.14	1.59	3.16	4.75	6.33
Annual Sulfur Dioxide Limit	0.54	0.50	0.50	0.50	0.67	0.89
	(Percent Pollutant Control)					
Design Control Efficiency	0	70	70	90	90	90
Actual Control Efficiency	0	58	70	85	86	86
Scrubber Type	NA	Dry	Dry	Wet	Wet	Wet
	(Dollars per Kilowatt)					
Total Costs for SO_2 and Particulate Control	71	145	146	228	231	235
	(Mills per Kilowatt-Hour)					
Operation and Maintenance Costs--Fixed and Variable	0.10	2.22	2.69	3.9	4.37	4.8
	(Percent)					
Capacity Penalty	0	1.54	1.58	2.23	2.45	2.61
Energy Penalty	0	2.22	2.43	3.50	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.5. ESTIMATED COST PENALTIES IN OPTION IV ASSOCIATED WITH FUEL SWITCHING (Per kilowatt of capacity)

Initial Coal by Pounds SO_2 Per Million BTUs	New Coal Types by Pounds SO_2 Per Million BTUs Consumed					
	0.8	1.2	1.76	3.92	6.67	8.89
0.8	x	x	x	x	x	x
1.2	20	x	x	x	x	x
1.76	30	20	x	x	x	x
3.92	60	30	20	x	x	x
6.67	60	60	30	20	x	x
8.89	60	60	60	30	20	x

SOURCE: Congressional Budget Office.

NOTE: No scrubbers are assumed to figure in this estimate.

distribution, and transportation costs by mode. For the electric utility industry, forecasts were made of generation, changes in emissions, fuel use (including coal by type), and changes in costs for capital, fuel, operation and maintenance, and pollution control for alternative standards.

The model generates a least-cost equilibrium solution using a standard linear programming formulation, which simultaneously balances supply and demand requirements for each region of the United States. This equilibrium solution reflects a wide variety of conditions affecting both the coal and electric utility industries, including both governmental policies and non-governmental factors. The results are summarized regionally in terms of production, consumption, and prices for coal for utilities. These provide the basis for estimating other impacts, such as capital requirements and environmental effects.

The CEUM links the coal and electric utilities industries. The electric utility sector in the model is structured in such a way as to minimize total generation and distribution costs. The model forecasts economic capacity expansion and dispatch. The model can operate existing capacity of various plant types and/or build new capacity. Further, it can operate capacity in any of four local categories--base, cycling, seasonal peaking, and daily peaking. It is designed to build and operate capacity of various plant types in the various load categories such that the total of fuel, capital, and operations costs is minimized.

Different pollution control regulations (for sulfur dioxide and other pollutants) that apply to specific types of plants in different jurisdictions are explicitly modeled. For older sources, actual state emission limitations are used. For sources subject to NSPS, either the federal standards or assumed PSD or state limit is used, whichever is lower (see Table B.6). Hence, consumption of any one coal type depends on its price relative to other coal types and other compliance alternatives. Rather than merely minimizing delivered coal costs, the model minimizes the total costs of generating and distributing electricity.

The current NSPS and all alternatives were simulated as follows. All existing sources were assumed subject to the applicable state and local standards contained in the State Implementation Plan (or PSD determination, if lower), and all new sources were subject to the alternative federal emissions standards being examined, except when those would be superseded by more stringent state regulations in effect as of 1980. Option IV was modeled similarly, except that new sources were permitted to increase emissions above current NSPS levels if equivalent reductions of sulfur dioxide (beyond levels regulated by the SIP) were obtained at one or more existing sources. In all cases, the least-cost solution for electricity production was simulated.

Table B.7 outlines the assumptions used in the model simulation analysis.

TABLE B.6. PREVENTION OF SIGNIFICANT DETERIORATION ASSUMPTIONS FOR SPECIFIED STATES (In pounds of sulfur dioxide per million BTUs consumed)

	State New Source Emissions Standards	Assumed Federal PSD Emissions Limit
Montana	1.20	1.20
Wyoming	0.20	0.20
Colorado	0.40	0.20 a/
New Mexico	0.34	0.34
Utah	0.12/1.20	0.20 a/
Arizona	0.80	0.20 a/
Nevada	1.20	0.20 a/
North California	0.13	0.13
South California	0.13	0.13

SOURCE: Congressional Budget Office.

a/ Denotes states where assumed PSD limit is more stringent than state standards.

TABLE B.7 MAJOR ASSUMPTIONS USED IN CBO/ICF ANALYSIS

Parameter	Base Case	Comment
Energy and Economic Conditions		
GNP (Percent per year real growth	1980 - 1985 = 2.9 1985 - 2000 = 3.0	Modified from recent CBO economic forecasts.
World Oil Prices (1980 dollars)	1985 = 37.29 1990 = 41.17 1995 = 45.46 2000 = 50.19	Higher oil prices encourage the substitution of coal for oil by electric utilities, within assumed financial and institutional constraints. Estimates of future oil prices assume a 2 percent per year real escalation in price, which is based on recent CBO forecasts.
Natural Gas Prices and Availability	As estimated by ICF Gas Models	
Electric Utility Energy Demand		
Electricity Growth Rate (Percent per year)	1979 - 1985 = 3.2 1985 - 1990 = 2.7 1990 - 1995 = 2.7 1995 - 2000 = 2.7	Growth rates for electricity are expected to remain well below pre-1980 historical averages. This is consistent with Wharton Economic Forecasting Assumptions (WEFA) and ICF analysis of the electricity markets
Nuclear Capacity	1985 = 78 1990 = 121 1995 = 141 2000 = 175	Since coal is a substitute for nuclear power in generating electric power, variation in nuclear capacity levels leads to variations in national coal production forecasts. The estimates are based on a unit-by-unit review.
Substitution of Coal for Oil and Gas	Reconversions assumed and accelerated replacement allowed but deterred by capital cost penalty and state limits.	Current and projected oil and gas prices indicate it is economic to substitute coal for oil and gas in substantial proportions, but institutional and financial constraints make this unlikely to occur. In the base case, about 18 gigawatts of conversions are assumed. The accelerated replacements of oil and gas units with new coal units are inhibited by adding capital cost penalty to the cost of a new coal unit and by limiting the amount of new coal capacity in key states--California, Texas, Louisiana, and Florida.

(continued)

TABLE B.7 (Continued)

Parameter	Base Case	Comment
Power plant and Industrial Fuel Use Act		The off-gas provision is not in effect, but the base-year gas use rule remains in 1985 only with the base year quantity defined as the maximum use during 1970s. Oil and gas-fired combined cycle are prohibited for new power plants.
Utility Capital Costs per kilowatt (1980 dollars)	Coal = About 850 Nuclear = 1,020-1,254 Turbine = 223-235	Capital costs for new power plants are based on the most recent (1979) technical data developed by EPRI. They include a total real escalation of 12 percent between 1978 and 1985, as modified by CBO.
Non-Utility Coal Demand		
Industrial Coal Use (Per million tons)	1985 = 80 1990 = 117 1995 = 171 2000 = 225	Based on recent ICF analysis.
Steam Coal Exports (Per million tons)	1985 = 40 1990 = 84 1995 = 120 2000 = 196	Long-term estimates of export demands for steam coal are based on recent ICF in-depth analysis of the export markets.
Metallurgical Coal Use (Millions of tons)		
Export	1985 = 51 1990 = 56 1995 = 58 2000 = 60	Export demand for metallurgical coal is assumed to decline from abnormally high levels in 1980, and then increase only slightly. Metallurgical exports are assumed to be primarily low-sulfur, high-Btu coals.
Domestic	1985 = 73 1990 = 67 1995 = 66	Domestic use of metallurgical coal is expected to decline due to the sluggish growth of the U.S. steel industry and continued process changes that reduce the use of coke per ton of product.

(continued)

TABLE B.7 (Continued)

Parameter	Base Case	Comment
Synfuels (Coal input in millions of tons)	1985 = 7 1990 = 24 1995 = 82 2000 = 139	Estimated demand for coal-derived synfuels in 1985 has been reduced from earlier forecasts to reflect a reduced government role in promoting commercial synfuels production and a project-by-project assessment of announced plans.
Residential and Commercial Coal Use	1985 = 8 1990 = 9 1995 = 10 2000 = 11	Residential and commercial coal use is expected to increase slowly. Residential and commercial demand is assumed to be limited to low- and medium-sulfur coals.
Financial Parameters		
Inflation Rate (Percent per year)	1980 - 2000 = 8.0	The annual inflation rate is assumed to be 8 percent per year, consistent with recent CBO forecasts.
Discount Rates (Percent per year)	Coal Mine = 14.48% Utility = 12.61%	These nominal rates are based on a 6.0 percent real rate for mining and a 4.27 percent real rate for utilities.
Coal Transport Rates—Rail, Barge, and Truck (Percent total real escalation)	1979 - 1985: East = 25.0% West = 25.0%	Transportation rates are estimated to increase in real terms through 1985 as allowed under the Staggers Rail Act.
Mining Costs (Dollars total real escalation)	1980 - 2000: Capital = 0.0% Labor = 0.0% Materials = 0.0%	Capital, labor, and materials are assumed to remain constant in real terms. Productivity increases are assumed to offset any real cost escalation.
Other		
Federal Leasing Policy	Enough	It is assumed that enough coal will be leased by 1985 and later to avoid artificially driving up market prices.
Air Pollution Regulations	Most recent federal and state rules.	Controls on utility emissions of SO_2, NO_x, and TSP are subject where applicable to federal NSPS, revised NSPS and PSD rules; or to state SIP rules if more stringent.

APPENDIX C. FINANCIAL EFFECTS OF DIFFERENT ACCOUNTING METHODS FOR CONSTRUCTION WORK IN PROGRESS

Particular accounting methods used by the electric utilities can influence the financial condition of the industry and the costs of producing power. They can also affect the industry's costs to meet the Clean Air Act's NSPS.

The most significant regulation pertaining to utility finances is the state public utility commissions' treatment of "construction work in progress." In most instances, utilities may not earn returns on CWIP investments before their new facilities are fully operational. To account for the lost revenue a firm incurs while a facility is being built, the state PUC usually allows a utility to establish an "allowance for funds used during construction" account. This account essentially represents the value of total CWIP capitalized each year at a rate of return set by the commission. The capitalized annual CWIP appears as income for accounting purposes, but it is not realized as cash until the facility is service. When the facility does begin operation, the capitalized AFUDC is added to the total investment, forming the rate base. The rate base is then depreciated over the operating life of the facility, with the utility earning an annual return on the undepreciated portion. Although the utility is ultimately allowed to earn a fair return on its construction costs, it must borrow or otherwise maintain its cash flow in the interim.

Table C.1 compares the finances of a new 500-megawatt plant under three different accounting and pollution control hardware assumptions. Each facility is assumed to have begun construction in 1980 with expected start-up in 1987. The first facility includes a scrubber as part of the total plant, and its rate base is calculated to include AFUDC. The second facility also has a scrubber, but the utility is allowed to earn a return on its CWIP investment before plant start-up. The third facility has no scrubber, and similar to the first facility, its rate base includes AFUDC. The calculations assume either all or none of the facility is subject to CWIP or AFUDC, depending on the case.

Figure C.1 shows the electricity cost curves for each plant over its lifetime. Both plants using AFUDC in the rate base do not start charging for electricity until the first year of operation. The plant using CWIP, on the other hand, begins adding a small charge to existing electricity costs during the years of construction. This added charge from passthrough of

TABLE C.1. FINANCIAL COMPARISON OF A NEW 500-MEGAWATT POWER PLANT UNDER DIFFERENT ACCOUNTING AND POLLUTION CONTROL HARDWARE ASSUMPTIONS (In millions of dollars)

	Plant and Scrubber with AFUDC (In Rate Base)	Plant and Scrubber with CWIP (In Rate Base)	Plant with No Scrubber, AFUDC (In Rate Base) c/
Total Plant in Rate Base Start-up (nominal dollars) a/	1,195	892	933
Total Interest During Construction (nominal dollars) a/	303	124	229
Cost to Consumers Over Life of Plant (1980 dollars) b/	86,542	64,394	68,020

SOURCE: Congressional Budget Office.

a/ Interest rate, AFUDC, and return on rate base calculated at 13.74 percent.

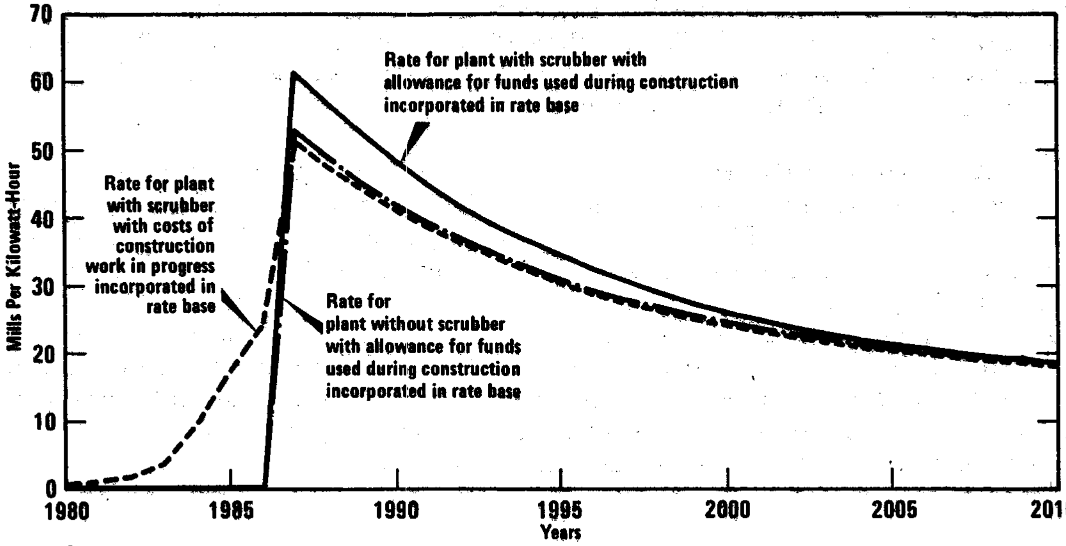
b/ Discount rate used was 10 percent over 25 years.

c/ Life cycle costs of this facility also include higher fuel cost for low-sulfur coal.

CWIP to existing electricity costs would result in high electricity rates during the years preceeding plant start-up. As Table C.1 shows, however, both plants using AFUDC as an accounting procedure have larger rate bases, higher interest costs, and greater electricity costs over the life of the plant than the facility obtaining a return on CWIP, which is assumed to offset a portion of its annual investment during construction.

Figure C1.

Projected Electricity Rates Under Different Accounting Assumptions: 1980-2010



SOURCE: Congressional Budget Office.

NOTE: Transmission and distribution rates not included.

It is important to note that the cost of AFUDC to a plant with a scrubber is approximately equal to the cost of the scrubber itself. The present value difference in total investment (with interest) of the first two plants shown in Table C.1 is equivalent to $184 per kilowatt-hour. This cost is approximately equal to a wet limestone scrubber without particulate controls.

The reason AFUDC is employed as an accounting procedure primarily involves the reluctance of state PUCs to force present consumers to subsidize the rates of future consumers. Though over the long term, utilities and ratepayers enjoy lower costs when CWIP is incorporated in the rate bases, the prospect of yearly rises in electricity rates before a plant's start-up remains an unattractive option to most PUCs.

A recent survey reveals that many states allow some CWIP in the rate base, but such treatment is not uniform, and the average amount allowed is only approximately 20 percent. 1/ In the survey, 44 state PUCs, accounting

1/ General Accounting Office, "Construction Work in Progress Issue Needs Improved Regulatory Response for Utilities and Consumers" (June 23, 1980).

for $38 billion out of the $42.5 billion of total CWIP in 1978, provided information on their treatment of CWIP. In these 44 states, 23.4 percent of CWIP was allowed in the rate bases. The range of CWIP allowed in rate bases nationwide was between 21 and 23 percent in 1978. This 21 to 23 percent figure may be misleading, since state PUCs often employ an "AFUDC-offset" when CWIP is allowed in the rate base. This offset essentially subtracts part of the real income generated by CWIP and replaces it with AFUDC accounting income.

Although AFUDC represents only one accounting procedure that can adversely affects the financial condition of a utility, it is perhaps the most important one. As AFUDC increases as a percent of total revenues, the quality of a utility's earnings diminishes. This reduction in the quality of earnings is perceived negatively by the investment community, which, in turn, becomes reluctant to continue lending, resulting in increased cost of capital for utilities. A 1 percent rise in interest rates can add $25.6 million to the total cost of a new 500-megawatt facility. Such potential costs and those actually associated with financing a utility subject to AFUDC largely overshadow the cost of most air pollution controls.

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