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Volume II
Economic and Financial Impacts

Interagency Energy/Environment R&D Program Report

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REVIEW OF NEW SOURCE PERFORMANCE STANDARDS FOR COAL-FIRED UTILITY BOILERS

VOLUME II – ECONOMIC AND FINANCIAL IMPACTS

March 1978

DISCLAIMER

ABSTRACT

This two volume report summarizes a study of the projected effects of several different revisions to the current New Source Performance Standard (NSPS) for sulfur dioxide (SO_2) emissions from coal-fired utility power boilers. The revision is assumed to apply to all coal-fired units of 25 megawatts or greater generating capacity beginning operation after 1982. The revised standards which are considered are: (1) mandatory 90 percent SO_2 removal with an upper limit on emissions of 1.2 lb SO_2 per million Btu; (2) mandatory 80 percent SO_2 removal with the same upper limit; (3) no mandatory percentage removal with an upper limit of 0.5 lb SO_2 per million Btu. In addition, effects of revising the NSPS for particulate emissions from the current value of 0.1 lb per million Btu down to 0.03 lb are quantified. Projections of the structure of the electric utility industry both with and without the NSPS revisions are given out to the year 2000. Volume I discusses air emissions, solid wastes, water consumption, and energy requirements. Volume II discusses economic and financial effects, including projections of pollution control costs and changes in electricity prices.

PREFACE

This report is one of several volumes being submitted by Teknekron to the U.S. Environmental Protection Agency under contract 68-01-3970, "Review of New Source Performance Standards for Sulfur Dioxide Emissions from Coal-Fired Steam Generators." This volume discusses the economic and financial implications of alternative New Source Performance Standards as they will apply to the U.S. electric utility industry. Volume I, which is being submitted concurrently, presents the emissions and non-air quality environmental implications of these SO_2 control alternatives. A third volume discussing the air quality implications of the emissions control alternatives is anticipated, as is a final volume containing a series of "issue papers" summarizing results which bear on specific policy issues relating to EPS's proposal to revise the current standard.

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1.0 SUMMARY AND CONCLUSIONS

The Environmental Protection Agency asked Teknekron to assess the economic and financial impacts of alternative New Source Performance Standard (NSPS) revisions on the electric utility industry. This assessment has been accomplished both from a regional as well as national perspective for a number of candidate NSPS revisions, presented in Table 1.1. For this analysis Teknekron has employed its Utility Simulation Model (USM), which generates an integrated, internally consistent analysis of the economic and financial impacts of alternative environmental regulations on the operations of the nation's investor and publicly owned electric utilities. Figure 1.1 illustrates the interaction of the economic and financial analysis undertaken in the Financial module of the USM with the utility planning, dispatching, and environmental analysis.

The remainder of this volume is organized in the following manner. Chapter 2 describes the structure, composition, and recent performance of the electric utility industry over the last decade. Chapter 3 contains the economic and financial impact analysis and results of alternative NSPS revisions. Attention has been paid not only to the economic and financial impacts on the industry, but to the potential impacts on the industry's customers and the public. Using the Financial module of the USM, Teknekron has examined the regional price, pollution control cost, and investment effects of these alternative NSPS revisions. Financial effects on utilities' return on investment, interest coverage ratio, and earnings quality are analyzed in addition to the potential impact of the NSPS revisions on the nation's capital markets. Chapter 4 presents an assessment of the coal-nuclear trade-off in the context of changed environmental regulations. Appendix A contains a discussion of issues surrounding the capital formation prospects of electric utilities. Appendix B provides some detail as to the costs of sulfur dioxide and particulate controls.

Table I.1

Alternative New Source Performance Standard Revisions Considered

	BASELINE M 1.2(0)0.1	M 1.2(90)0.1	M 1.2(80)0.03	M 1.2(90)0.03	M 0.5(0)0.03	BASELINE H 1.2(0)0.1	H 1.2(90)0.1	H 1.2(80)0.03	H 1.2(90)0.03
Electricity Demand Growth	Moderate*	Moderate*	Moderate*	Moderate*	Moderate*	High+	High+	High+	High+
Ceiling for SO_2 Emissions**	1.2	1.2	1.2	1.2	0.5	1.2	1.2	1.2	1.2
Percent Removal Requirements for SO_2	0	90%	80%	90%	0	0	90%	80%	90%
Particulate Standard**	0.1	0.1	0.03	0.03	0.03	0.1	0.1	0.03	0.03

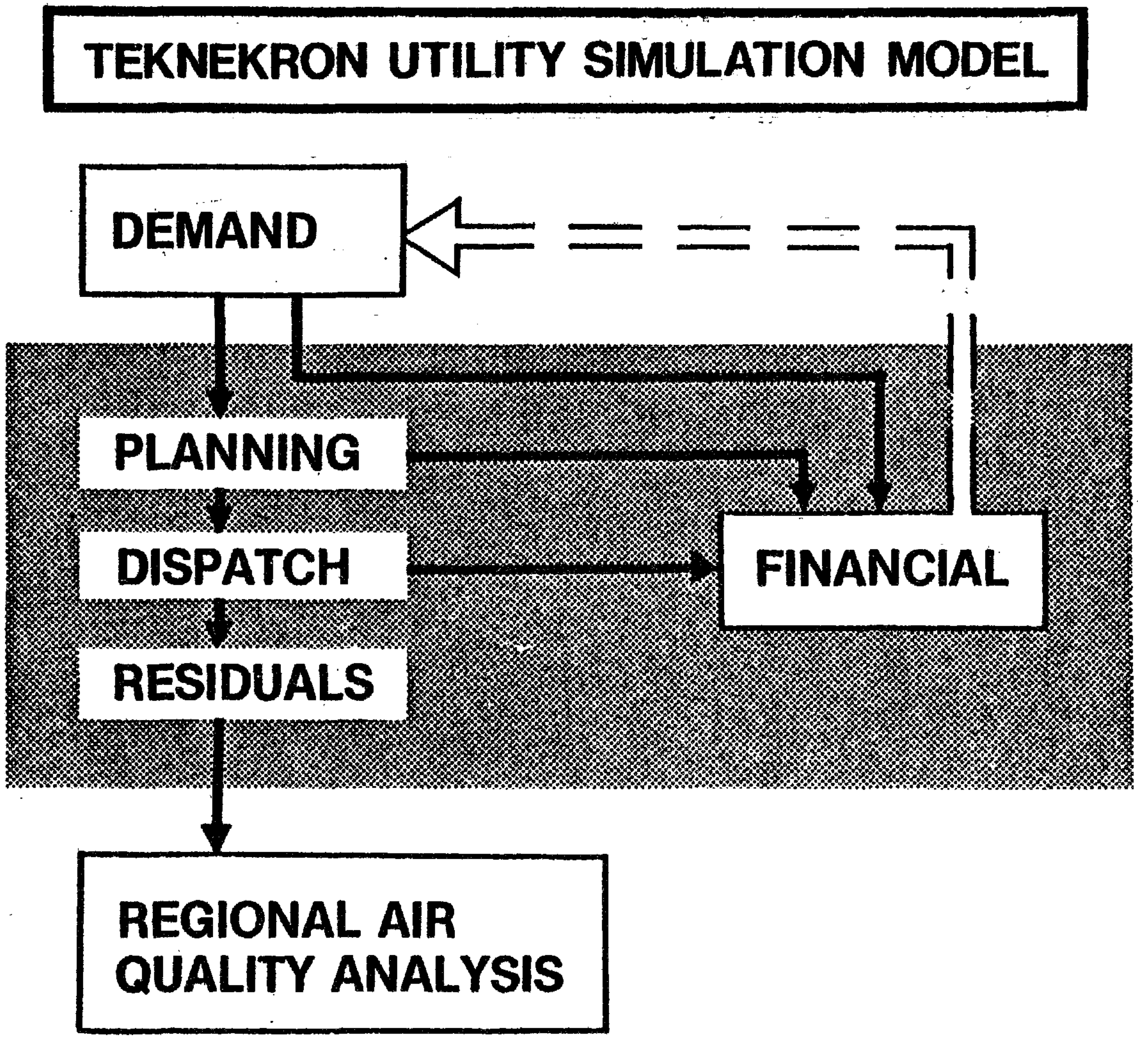
* 5.8% per year to 1985; 3.4% thereafter.

** In $lb/10^6$ Btu

\+ 5.8% per year to 1985; 5.5% thereafter.

NOTE: Standards other than the baseline cases are assigned to apply only to coal-fired generating units beginning commercial operation in 1983 or later. See Volume I for a more detailed discussion of the scenarios analyzed.

Figure 1.1


TEKNEKRON UTILITY SIMULATION MODEL
DEMAND
PLANNING
DISPATCH
RESIDUALS
FINANCIAL
REGIONAL AIR
QUALITY ANALYSIS

1.1 PRINCIPAL ECONOMIC IMPACTS

- The largest increases in national economic factors facing the electric utility industry due to alternative NSPS revisions over the 1986-1995 period (when the majority of economic and financial impacts will occur) are forecast for pollution control costs and investment. Nationally, total costs facing the utility industry under the NSPS revisions increase at most 5 percent over the 1986-1995 forecast period. Net profits for the industry may decrease as much as 2.8 percent under the high growth cases. Pollution control investment may increase to 10 percent of total industry investment over the 1986-1995 period under high growth. Comparing the forecasts of the 80 and 90 percent SO_2 removal standards over the 1986-1995 period indicates that there is little variation in pollution control expenses (costs and investment) or in retail price of electricity.

- Changes in both national retail prices and per capita costs (total revenue/population) due to alternative NSPS revisions are forecast not to be large over the 1986-1995 period; the average yearly increase in real prices is forecast to be approximately 0.5 percent at most, under high growth, less than 0.2 percent under moderate growth. National per capita costs are forecast to increase at most by 0.4 percent per year over the 10-year period.

- There are significant regional variations in the economic impacts. Retail prices of electricity, in real terms, are forecast to increase over 10 percent in the West South Central region, which includes the Gulf coast area where relatively large amounts of coal-fired capacity subject to the NSPS revisions are planned to be constructed to replace gas-fired capacity. Other regions where retail price increases may be significant under high growth include North Mountain, West North Central, East North Central and South Atlantic. *

- Regional per capita costs vary greatly over the 1986-1995 forecast period. As before, the West South Central region incurs the largest increases, over 10 percent under the high growth case. The impact of NSPS revisions on per capita costs for the other regions is not so significant. The forecasted differences between the 80 percent and 90 percent SO_2 removal cases are not large for national per capita costs. The New England, West South Central and South Mountain regions incur the largest differential impact between the 80 percent and 90 percent cases.

- Both pollution control costs and direct pollution control investment are forecast to increase significantly over the 1986-1995 period as a result of the NSPS revisions considered. As expected, direct pollution control investment expenditures increase more than costs. The largest increases occur under the high growth, 90 percent SO_2 removal cases; national direct pollution control investment expenditures increase between 174 and 195 percent (to between $48 and $52 billion in 1975 dollars) and pollution control (operation and maintenance) costs increase between 37 and 41 percent (to between $51 and $57 billion in 1975 dollars). Direct pollution control

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* See Table 3.2 for regional definitions.

investment increases from between 2 and 3 percent for the baseline cases to at most 7 to 10 percent of total industry investment under the 90 percent SO_2 removal cases. While pollution control expenses are higher under the 90 percent cases than the 80 percent cases, on average for the nation over the 1986-1995 period, they are less than 8 percent different.

- In addition to direct pollution control investment expenditures that the electric utility industry is forecast to make under the NSPS revisions, somewhat higher plant investment expense will be incurred because of the FGD system-related capacity penalties.* Based on information supplied to Teknekron on these penalties, we estimate that between $2 and $5 billion may be required for additional plant investment over the 1986-1995 period. These results represent less than one percent of forecasted total industry investment over the period.

- Again, the West South Central region incurs the largest increases in pollution control costs and direct pollution control investment, which are forecast to increase a maximum of 85 and 300 percent respectively over the 1986-1995 period. Under the high growth cases, six of ten regions' direct investment costs increase over 100 percent. Because of its relatively small dependence on coal-fired capacity, New England bears the lowest increase in costs and investment.

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* These capacity penalties are assumed to be between 5 and 6 percent.

1.2 PRINCIPAL FINANCIAL IMPACTS

Important financial parameters that were examined include the utilities' return on equity, their interest coverage ratios, and the quality of their earnings. These factors were analyzed both nationally and regionally.

- Alternative NSPS revisions for both the moderate and high growth cases are forecast as having relatively little financial impact. Nationally, the utilities' return on equity decreases between 3.3 and 6.5 percent; the interest coverage ratio decreases 1.3 percent under high growth, remains constant under moderate growth. The quality of earnings, measuring the extent of the utilities' earnings that are composed of noncash AFDC, decreases relatively little, 2.6 percent, under moderate growth and 6.8 percent under high growth for alternative NSPS revisions.

- Most affected from a financial perspective is the West South Central region, principally because relatively large amounts of coal-fired capacity subject to the NSPS revisions are forecast to be constructed to replace much of the present gas-fired capacity. Other regions' financial impacts due to NSPS revisions are much smaller.

- The utilties' return on equity on a regional basis is generally stable under NSPS revisions. The West South Central and North Mountain are the most affected regions.

- Regional interest coverage ratios generally are not significantly affected by the NSPS revisions. The most affected regions are West South Central, East North Central, and South Mountain.

- Quality of earnings for the utility industry is affected relatively more by different electricity growth rates and overall construction programs than by the NSPS revisions. The most adversely affected regions are East South Central and West South Central.

- The impact on long-term external financing of the NSPS revisions among the nation's investor-owned utilities is felt most on common stock financng. Neither long-term debt or preferred stock issues are greatly affected; the greatest increase is in long-term debt under high growth, representing 2.1 percent increase over the 1976-1995 period. Common stock issues increase 7 percent and 8.6 percent under the moderate and high growth 90 percent SO_2 removal cases, respectively.

- The impact of NSPS revisions on the nation's macro-economic activities and capital markets is relatively small. Additional direct investment by the utility industry due to NSPS revisions in 1990 is forecast to be at most $6.2 billion in 1975 dollars, representing 0.25 percent of real GNP and 1.6 percent of gross private domestic investment.

2.0 OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY

Over the recent past the electric utility industry, already one of the largest in the nation, has grown in importance within the energy sector. In 1950, 17 percent of the nation's primary energy supplies was used to produce electricity. By 1975, this figure had increased to 28 percent. Between 1970 and 1975, electric utility construction work in progress increased over 80 percent in real terms, to over $26 billion. Of this amount, almost $2.2 billion was for environmental-related construction.

Electric utilities are highly capital intensive: in 1975 the amount of investment (gross electric utility plant) per employee was $334,480, a 37 percent increase since 1970. In addition, $3.60 of net capital investment was required to produce $1 of revenue. In 1975, the total electric utility industry had $163 billion invested in plants, making it among the largest in the nation. As will be discussed below, this capital intensity and size both contribute to the utilities' significant impact on the nation's capital market.

Not only is the electric utility industry large, but it is one of the fastest growing in the nation. As Table 2.1 illustrates, both total kilowatt-hour (kwh) sales and total revenues have increased greatly over the past decade. Between 1965 and 1975, total kwh sales increased by 68.6 percent, whereas the real gross national product increased by 27.8 percent.

2.1 INDUSTRY STRUCTURE

Although all electric utilities produce the same product, they can differ significantly by type of ownership, customer mix, cost structure and operation. Since the first electric generating plant began commercial operation in 1892, the

Table 2.1

Total Electric Utility Industry Sales and Revenues, 1965-1975

Year	Total Energy Sales to Ultimate Customers (10^9 Kwh)	Total Revenue from Ultimate Customers (10^6 \$)
1965	953.4	15,022+
1970	1,391.4 (46.0)*	23,434 (55.9)
1975	1,607.4 (13.4)	73,447 (68.1)

Source: Federal Power Commission

* Figures in parentheses indicate percent increase from previous period.

\+ Adjusted by electricity Price Index. In 1967 dollars.

industry has undergone continuous development. The industry now is comprised of over 3,000 operating utilities that are either privately owned, nonfederal government, REA cooperatives, or federal projects.

2.1.1 Privately Owned Utilities

The privately owned electric utilities dominate the entire utility industry despite their few numbers. While representing less than 15 percent of the nation's utility systems, they account for the largest share of industry sales revenues, generated output and customers, as illustrated in Table 2.2.

The growth of the private sector, like that of the whole industry, has been impressive; since 1965 the privately owned electric utilities' total power generation has increased by 68.2 percent. Among the privately owned systems there is great disparity in system size. A large number of private firms are small companies serving nonurban, non-industrial markets. Like the small publicly owned utilities, these firms are usually distribution-only systems, purchasing their power requirements from the larger utilities.

Within the privately owned sector the large utilities account for a disproportionate share of generated output, assets, and revenues. These large systems have grown in size both through internal expansion and through acquisitions of other electric utilities. In 1970 the fifty largest privately owned electric utility systems, representing less than 2 percent of the nation's operating electric systems, generated 64 percent of the industry's net kwh output. The 213 Class A & B utilities,* representing approximately one-half of the privately owned operating utilities, accounted for nearly 100 percent of the privately owned electric utilities' assets and revenues.

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* The Federal Power Commission defines Class A utilities as those with annual electric operating revenues of more than $2.5 million. Class B utilities are those with annual electric operating revenues between $1 million and $2.5 million. Those utilities having annual electric operating revenues below $1 million are defined either as Class C or Class D, depending on their size.

Table 2.2

Comparative Size Characteristics, Privately and Publicly Owned Electric Utilities, 1975

	Private*	Public+
Total Sales (10^6 Kwh)	1,353,089 (84)**	254,353
Total Net Generation (10^6 Kwh)	1,486,676 (86)	245,778
Total Generative Capacity (Mw)	393,953 (81)	91,696
Total Electric Operating Revenue (10^6 \$)	39,639 (90)	4,341
Total Customers (millions)	63.5 (89)	7.9

Source: Federal Power Commission

* Privately owned Class A & B Utilities.

\+ Includes municipal wholesalers, municipal retailers, federal projects, and state power authorities.

** Figures in parentheses indicate percent of total electric utility industry, private plus public utility figures.

These relatively few systems thus exert a pervasive influence on the entire industry's economic and financial performance. Much of the analysis of the utilities' performance in the following chapters will focus on these privately owned utilities.

2.1.2 Nonfederal Government Units

The largest number of electric utility systems, the nonfederal government systems, include city and town municipal utilities, county and state systems, and special utility districts. In 1975 these systems generated about 9 percent of the industry's production and 11 percent of industry sales. Between 1965 and 1975 nonfederal government systems increased their generation by 75.5 percent. In 1923 there were 3,084 such systems, but by 1975 the number had declined from this peak to approximately 2,000 with about two-thirds of them purchasing all of their power requirements from either privately owned or federal systems. The municipal systems are the most numerous of the nonfederal systems and vary greatly in size. Some serve only a few hundred customers, while others like the Los Angeles Department of Water and Power, the nation's largest municipal electric utility, serve over a million.

2.1.3 REA Cooperatives

The Rural Electrification Administration (REA), founded in 1936, has promoted the increased use of electric energy in rural America through the creation of rural electric service cooperatives. Federal financing of such cooperatives was necessary due to the apparent reluctance of private industry to provide electric service in rural areas. This reluctance was likely caused in large part by the relatively high distribution costs per customer, making rural electrification less profitable than urban service areas. The REA systems serve an average load density of about four customers per mile of line, which is about one-tenth the load density in urban areas.

When the cooperatives were first organized in the 1930s, they were almost exclusively distribution systems. As time passed and their loads grew, generation and transmission cooperatives were developed to supply the cooperatives' power requirements. The REA cooperatives now purchase about 75 percent of their wholesale power requirements; in 1940, 92 percent was purchased. Their largest single power source is the government sector, including federal systems, which supplied 45 percent of the cooperatives' requirements.

In 1975 the cooperatives accounted for almost 2 percent of the nation's generated kwh. These utilities have grown the fastest of any systems; between 1965 and 1975 the cooperatives increased their power generation by over 200 percent.

2.1.4 Federally Owned Utilities

The federal systems account for the second largest segment of industry capacity and generated energy. In 1975 they accounted for over 11 percent of the industry's net generation. Over the last decade, their generation increased 46 percent.

The five largest federal systems include the Bonneville Power Administration, the Southwestern Power Administration, the Southeastern Power Administration, the Department of the Interior's Bureau of Reclamation, and the nation's largest system, the Tennessee Valley Authority (TVA). Unlike the four other federal systems, TVA operates fossil-fuel and nuclear generating capacity in addition to hydroelectric facilities. These five systems sell most of their electric power to other publicly owned systems (municipals and cooperatives) in their operating regions, to a small number of large industrial purchasers, and to government agencies such as the Energy Research and Development Administration for nuclear diffusion and processing operations.

2.2 OPERATING COSTS

The utilities' operations can include generation, transmission, and distribution of electricity. The costs associated with these and other activities are presented in Table 2.3 (Privately Owned Utilities) and Table 2.4 (Publicly Owned Utilities). The differences in cost structures between the privately and publicly owned utilities are notable, indicating these firms' varying operating environments. With the exception of the municipal wholesalers, the publicly owned firm's power production costs are relatively higher than those of the privates. In the case of the municipal retailers, 56 percent of operating revenue is accounted for by power production costs, reflecting the higher costs of purchased power. In addition, the distribution costs are relatively higher for municipal retailers than privately owned utilities, illustrating their more distribution-oriented operations.

Also of interest is the "Other Costs" category, which includes depreciation and amortization allowances and taxes. This cost category for publicly owned utilities represents about one-half the relative size of those for privately owned utilities. This is due in large part to the relatively smaller amount of plant owned by the publicly owned utilities and different tax provisions.

Labor, capital, and fuel costs are the major operating costs faced by the electric utilities and have been increasing steadily. Between 1970 and 1975 total salaries and wages for reporting Class A & B privately owned utilities increased 50 percent to $4.06 billion; total employment grew over the same period 4.8 percent to 403,407 in 1975. This increase in salaries and wages is put in perspective when it is realized that the privately owned electric utilities' generated output increased only 25 percent between 1970 and 1975.

The utilities' construction cost is a very important factor in an industry that is so capital intensive. The costs of constructing electric power plants have risen dramatically over the past decade and are shown in Table 2.5. The Handy-

Table 2.3

Structure of Total Costs of Privately Owned Electric Utilities, 1975

Type of Cost	(10^3 \$)	
Power Production		
Fuel	14,545,313	(33)*
Purchased power	3,238,934	(7)
Other power production	1,314,383	(3)
Maintenance	1,403,897	(3)
Sub-Total	20,502,527	(46)
Transmission	502,186	(1)
Distribution	1,753,593	(4)
Customer accounting & sales	2,221,102	(2)
Administrative and general	1,100,347	(2)
Total Operation & Maintenance	26,079,755	(58)
Other Costs (depreciation, amortization, taxes, other)	9,995,463	(22)
Total Operating Costs	36,075,218	(81)
Utility Operating Income	8,522,889	(19)
Total Utility Operating Revenue	44,598,107	(100)

Source: FPC, Statistics of Privately Owned Electric Utilities in the United States, 1975.

* Figures in parentheses indicate percent of Total Utility Operating Revenue.

Table 2.4

Structure of Total Costs of Publicly Owned Utilities, 1975

Type of Cost	Municipal Wholesalers* (10^3 \$)	Municipal Retailers+ (10^3 \$)	Federal Projects (10^3 \$)
Power Production	216,192 (41)**	2,222,341 (56)	1,041,335 (56)
Transmission	16,004 (03)	38,390 (01)	92,831 (05)
Distribution	5,279 (01)	246,219 (06)	1,395 (00)
Customer Accounts & Sales	2,875 (01)	111,113 (03)	4,713 (00)
Administrative & General	27,207 (05)	205,307 (05)	57,960 (03)
Total Operation & Maintenance	267,557 (51)	2,822,770 (71)	1,198,234 (64)
Other Cost (depreciation, amortization, taxes, other)	49,815 (10)	498,257 (12)	105,037 (11)
Total Operating Costs	317,372 (61)	3,321,027 (83)	1,403,271 (75)
Utility Operating Income	204,995 (39)	676,163 (17)	472,424 (25)
Total Utility Operating Revenue	522,367 (100)	3,997,190 (100)	1,875,695 (100)

Source: FPC, Statistics of Publicly Owned Electric Utilities in the United States, 1975.

* Municipal wholesalers are those publicly owned utilities whose revenues from sales for resale are 51 percent or more of total utility operating revenues.

\+ Municipal retailers are those publicly owned utilities whose revenues from sales for resale are 50 percent or less of total utility operating revenues.

** Figures in parentheses indicate percent of Total Utility Operating Revenue.

Table 2.5

Price Indices for Components of Electric Utility Plant Construction, 1965-1975

Handy Whitman Public Utility Construction Index

	1965	1970	1971	1972	1973	1974	1975
Building*	87	121	133	144	158	190	211
Electric Light and Power**	89	119	128	135	144	171	200

Source: Statistical Abstract of the United States, 1976.

Note: Based on data covering public utility construction costs for 95 items in 6 geographic regions. Covers skilled and common labor; does not reflect tax payments nor employee benefit costs. (1967=100)

* Includes cost of components for power plant building construction.

** Includes cost of material and equipment for steam-electric plant generation (boilers, turbine-generators, coal and ash handling equipment, condensors and tubing, and cranes); includes separate listing for operations employees.

Table 2.6

Electric Utility Industry New Construction Expenditures, 1965-1975

	1965	1970	1975
Total National New Construction Expenditures (10^6\$)	73,747	94,855	132,043
Electric Light and Power Industry New Construction Expenditures (10^6\$)	2,589 (3.7)*	5,808 (6.1)	9,020 (6.8)

Source: Statistical Abstract of the United States, 1976

* Figures in parentheses indicate percent of national total.

Whitman Public Utility Construction Cost Indices, which measure the change in costs of constructing electric power plant buildings and of steam-electric generation equipment, have increased by 142 percent and 125 percent, respectively, over the 1965-1975 period. The utilities' new construction expenditures between 1965 and 1975 increased almost 250 percent, as shown in Table 2.6, and account for nearly 7 percent of the nation's new construction.

Fuel cost is the largest single operating cost faced by an electric utility, and represents between 70 percent and 80 percent of total power production costs (see Table 2.3). Table 2.7 illustrates the very large recent increases in fuel cost faced by the utilities. Between 1965 and 1975 the wholesale fuel price index increased over 100 percent. Figure 2.1 illustrates the relationships between fuel prices, fuel cost per kwh generated and fuel used per kwh generated.

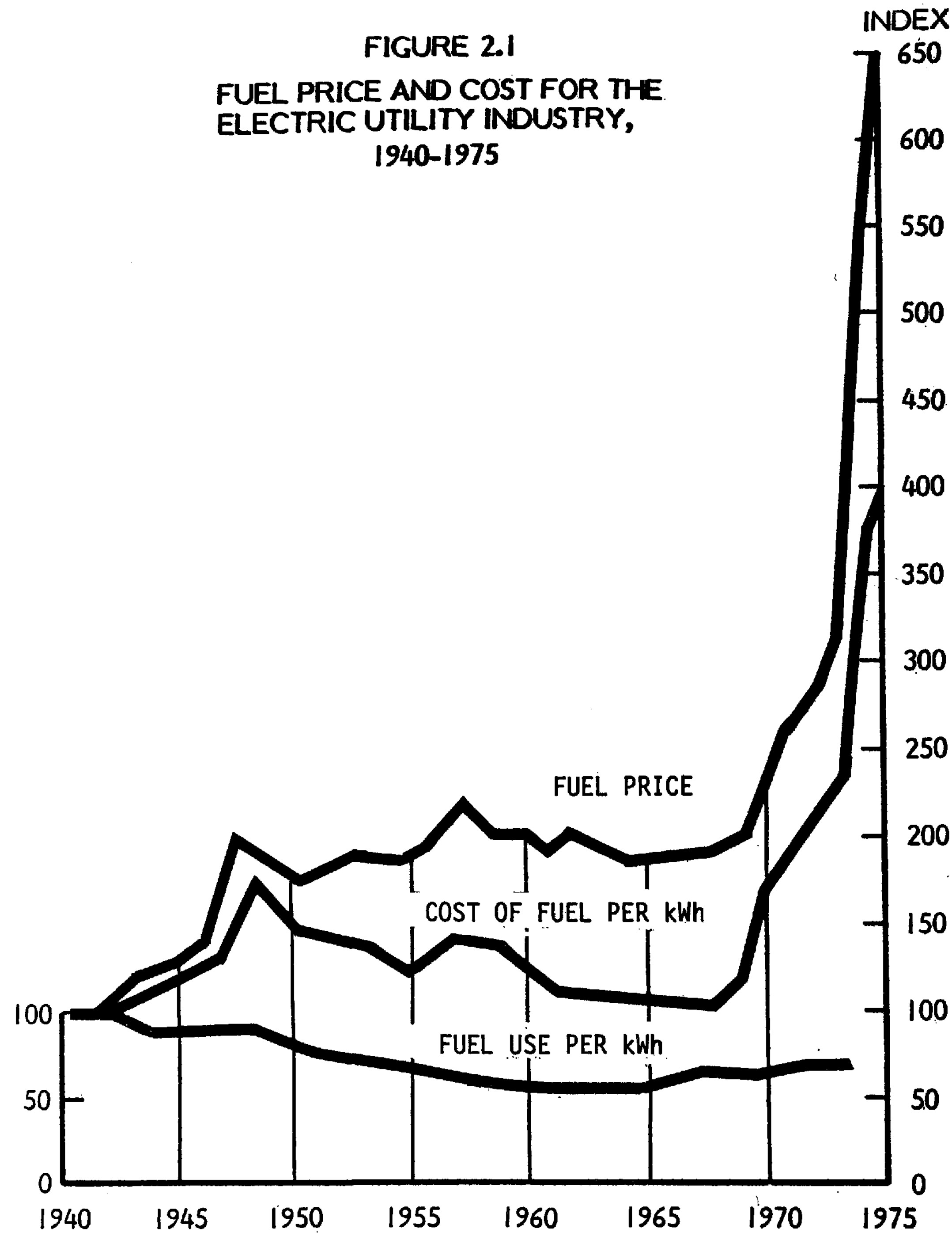
As shown in Figure 2.1, as the price of fuel has increased, the utilities have endeavored to reduce their relative usage of fuel (indicated by fuel use per kwh) through utilization of higher pressure and temperature steam generating equipment. In order to reduce fuel usage the utilities have employed more capital-intensive generating technologies (e.g., nuclear). Together, the increased fuel costs and rising consumption raised fuel expenditures of privately owned electric utilities for $3.73 billion in 1970 to $14.55 billion in 1975, almost a 400 percent increase.

2.3 ELECTRICITY PRICES

Each of these cost increases has been manifested most directly in the increased price of electricity. As is shown in Table 2.8, the electricity price index increased 69 percent between 1965 and 1975. This compares with the 71 percent increase over the same period for the consumer price index. Table 2.9 illustrates the regional breakdown for price increase between 1965 and 1975 in the residential, commercial and industrial customer classes.

FIGURE 2.1

FUEL PRICE AND COST FOR THE ELECTRIC UTILITY INDUSTRY, 1940-1975



NOTE: DATA BASED ON ALL FUEL USED IN ELECTRIC GENERATION AND EXPRESSED IN UNITS OF EQUIVALENT COAL.

INDEX: 1937-1941 = 100

SOURCES: 1937-1958, FEDERAL POWER COMMISSION
1959-1975, FEDERAL POWER COMMISSION AND EDISON ELECTRIC INSTITUTE

Table 2.7

Electric Utility Industry Fuel Consumption and Prices, 1965-1975

	1965	1970	1971	1972	1973	1974	1975
Millions of short tons of coal equivalent fuel	369	592	618	673	729	740	769
Wholesale Fuel Price Index (1967=100)	93.5	122.6	138.5	148.7	164.5	219.4	271.5

Source: Statistical Abstract of the United States, 1976.

Table 2.8

Electricity Price Index, 1965-1975

	1965	1970	1971	1972	1973	1974	1975
Electricity Price Index	99.1	106.2	113.2	118.9	124.9	147.5	167.0
Consumer Price Index	94.5	116.3	121.3	125.3	133.1	147.5	161.2

Source: Statistical Abstract of the United States, 1976. (1967=100)

Table 2.9

Percent Increase in Average Electricity Bills By Census Region and Customer Class, 1965-1975

Region	Residential	Commercial	Industrial
New England	88.2%	56.1%	95.7%
Middle Atlantic	14.5	38.9	55.1
East North Central	52.9	36.2	57.1
West North Central	41.9	33.6	47.8
South Atlantic	78.7	58.7	06.6
East South Central	78.0	40.0	89.1
West South Central	30.1	21.5	42.9
Mountain	39.0	41.3	58.2
Pacific	78.3	65.5	90.9
Noncontiguous	63.2	51.8	70.0
U.S. Average	72.3	63.8	89.6

Source: FPC, Typical Electrical Bills, 1975.

Overall, the New England region has faced the largest increases in average electricity bills. Both residential and industrial bills increased the most nationally between 1965 and 1975 in New England. The next most adversely affected region is the Pacific region, which had the highest increase in commercial bills, and significant increases in residential and industrial bills. These increases in labor, capital, and fuel costs have motivated the utilities to employ generation techniques that realize scale economics by substituting capital in place of labor and fuel, and raise thermal efficiencies to lower fuel costs.

2.4 PLANT SIZE, MIX AND EFFICIENCY

Electric utilities have met the continued increase in demand for electric power in large part by building larger generating units. By 1975, the largest unit size rose to 1,300 Mw, a 30 percent increase for the largest unit in service in 1965. These unit size increases were accomplished in order to realize the production economies of scale. The utilities have maintained that using larger generating units has allowed them to realize lower unit generating costs, thereby holding the price of electricity from rising even more rapidly.

Between 1970 and 1975 the utilities almost doubled the number of large (over 1,000 Mw) plants. Finally, by 1975 over three-quarters of the utilities' plants were larger than 100 Mw. By contrast, in 1960 only one-half of the utilities' plants were this size. In their move toward building larger generating units the utilities have also been building more nuclear and fossil-fueled base load units. Table 2.10 illustrates the industry's growing reliance on nuclear capacity. Between 1970 and 1975 the nuclear plants' generation increased almost 700 percent and supplied more than 10 percent of the nation's electricity. Fossil-fueled plants, however, remain the generating foundation for the utility industry, supplying over 80 percent of the generated kwh.

Over the past decade the utility industry has been predicting growing reliance on nuclear base load generation. Earlier predictions of much larger nuclear generating capacity, however, have not been realized, due in part to potential

Table 2.10

Net Generation of Electricity, (10^6KWH) Class A & B Utilities, 1965-1975

	1965	1970	1975
Fossil-fueled	735,601 (91.1)*	1,077,450 (90.7)	1,226,337 (82.1)
Nuclear	3,725 (0.5)	19,113 (1.6)	152,021 (10.2)
Hydro:			
-conventional	67,042 (8.3)	71,436 (6.0)	83,428 (5.6)
-pumped storage		3,423 (0.3)	7,780 (0.5)
Internal Combustion	707 (0.1)	16,067 (1.4)	23,398 (1.6)
TOTAL	807,075	1,187,489	1,492,964

Source: FPC, Statistics of Privately Owned Electric Utilities in the United States, years indicated.

* Figures in parentheses represent percent of column total; exclude station use.

Table 2.11

Privately Owned Electric Utilities Fossil-Fueled Steam Plant Capacity, 1965-1975

Year	Total No. of Plants	Over 100 Mw Capcity	Over 500 Mw Capacity	Over 1000 Mw Capacity	Total Mw Capacity
1965	653	398(61)*	89(14)	17(3)	159,141
1970	661	442(67)	155(23)	47(7)	220,536
1975	631	477(76)	222(35)	90(14)	366,504

Source: FPC, Statistics of Privately Owned Electric Utilities in the United States, years indicated.

* Figures in parentheses indieate percent of total plants.

pollution and siting considerations. The President's National Energy Act submitted to Congress on April 29, 1977, if enacted, could significantly affect the utilities' choice of base load capacity since the availability and price of oil and natural gas would be affected. In addition, Part F of the President's National Energy Act proposes amendments to the Coal Conversion Program that have the goal of converting oil- and gas-fired steam plants.

In the generation of electric power, one facet of economic efficiency is productive efficiency. From an engineering viewpoint this productive efficiency can be measured by the heat rate and thermal efficiency of the plant. The more efficient the plant, the lower is the heat rate measured by units of generated heat (Btu) per net unit of output (kwh).

Thermal efficiency measures how effectively available inputs, including labor, plant, fuel(s), and cooling facilities, are employed to produce electric power. The higher the thermal efficiency, the more effectively these inputs are being used. Changes in utilities' productive efficiency are measured by examining heat rates for fossil-fueled steam-electric plants in the total electric power industry. Figure 2.2 presents the trends in national average heat rates and thermal efficiency over the period 1950-1975. Average heat rates dropped almost 30 percent and thermal efficiency increased over 30 percent, a major technical accomplishment when facing diminishing returns.

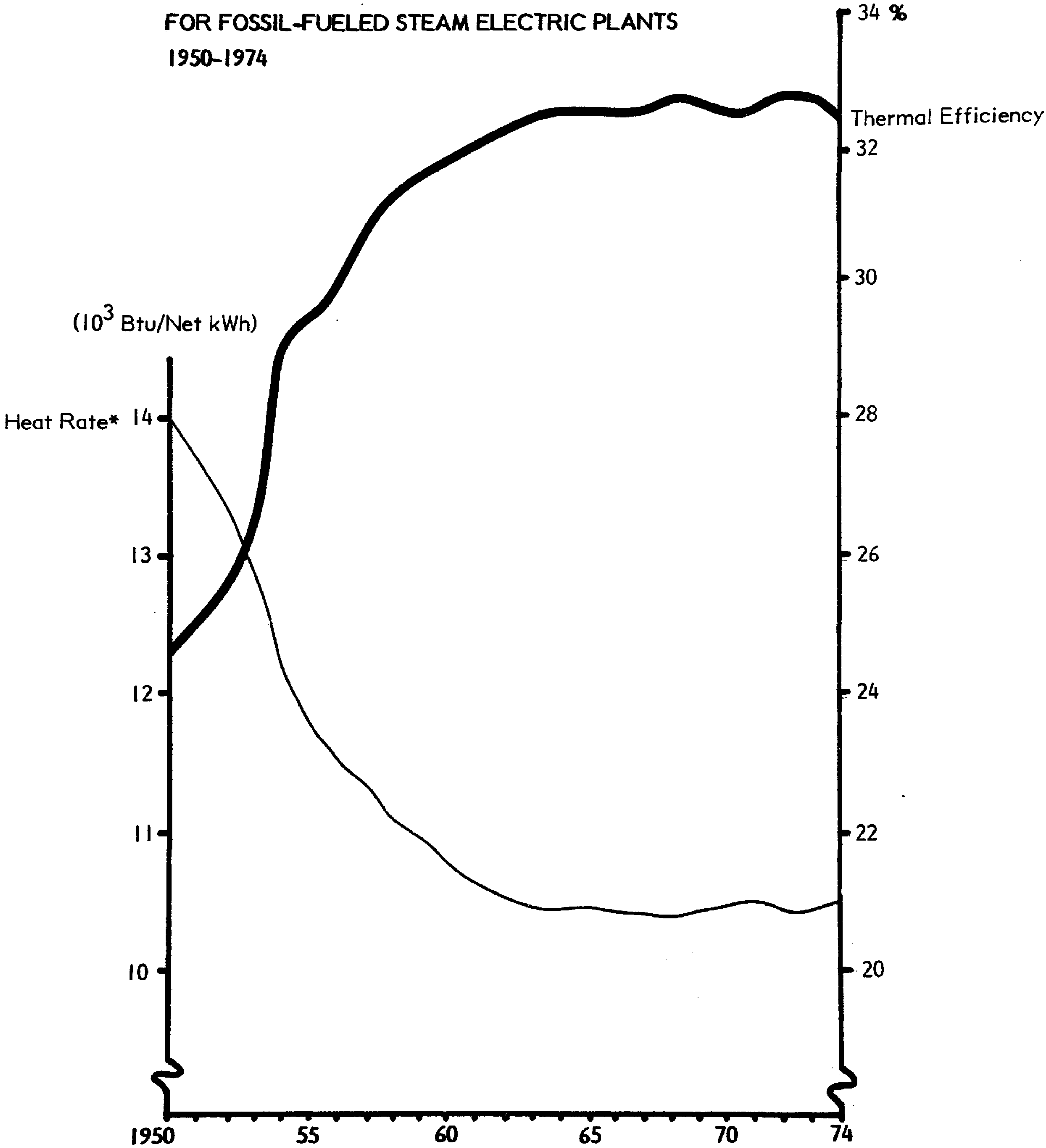
2.5 REGULATORY SETTING

Electric utilities have been considered "natural monopolies" and, as such, are subject to public regulation. This regulation takes place at three jurisdictional levels — federal, state, and local — and falls into three principal areas — issuance of securities, rates, and accounting practices.

At the federal level, the Securities and Exchange Commission (SEC) regulates the issuance of securities by nonexempt electric utility holding company affili-

FIGURE 2.2

NATIONAL AVERAGE HEAT RATES
FOR FOSSIL-FUELED STEAM ELECTRIC PLANTS
1950-1974



Source: Federal Power Commission
* Includes Internal Combustion Plants Prior to 1968.

ates, of which there were 70 in 1974. The SEC has authority also with respect to financial disclosure requirements. The Federal Energy Regulatory Commission (FERC, formerly the FPC) regulates the wholesale rates of all companies operating in interstate commerce. The FERC also regulates the issuance of securities for utilities in states where no such regulatory authority exists. Finally, the FERC prescribes accounting practices, requires detailed reporting on utility operations, and has the authority to approve development of hydroelectric projects on navigable rivers. A number of other federal agencies — such as the Environmental Protection Agency, the Department of Energy and the Nuclear Regulatory Commission — have regulatory authority which may significantly affect the financial condition of the electric utility industry, but the impact of these authorities on the industry's finance is generally considered to be indirect.

Most electric utility regulation takes place at the state level. Comprehensive state regulation of electric utilities began in 1907, when the New York Public Service Commission was created and the Wisconsin Railroad Commission was given regulatory authority over electric and other utilities. By the 1920s, electric utilities were regulated by more than two-thirds of the states. With the implementation of statewide regulatory authority over electric utilities by Minnesota and South Dakota in 1975 and Texas in 1976, 49 of the 50 states now exercise such authority.*

The areas in which state commissions generally have regulatory authority include

- Determining the appropriate rate of return on the utility's equity investments.
- Determining which cost elements should be included in the rate base or in operating costs, and thus are to be paid by consumers, and which elements should be excluded, and thus are to be paid by the investors.

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* Nebraska, which has no privately owned electric utilities, is served by public power districts and cooperatives.

- Approving a rate structure which distributes costs with respect to classes of customer or types of service.
- Approving the issuance of securities.
- Prescribing accounting, auditing, and reporting standards.
- Approving reorganizations, mergers, and consolidations.
- Certifying and licensing plant expansion
- Ensuring safety and service reliability.

In addition to these powers, state commissions have a responsibility to ensure that their current decisions do not endanger the financial viability of regulated utilities to the extent that the utilities are unable to accommodate the needs of customers in the future.

2.5.1. Regulatory Interaction with Utilities

Over the past five years, as the industry's capital and operating costs have risen significantly (see Table 2.5), utilities have spent an increasingly large amount of time before regulatory commissions in an attempt to recover costs through rate increases. The result has been an increase in the time necessary for the public utility commissions to decide on the utilities' rate increase requests. This increased time for regulatory case review has been referred to as "regulatory lag". Table 2.12 illustrates the dollar amounts of rate increases granted annually over the period 1970-1975, which grew from about $500 million in 1970 to more than $3 billion in 1975. However, far more significant to the financial condition of the industry was the fact that dollar amounts awaiting rate inclusion approval due to regulatory lag grew from about $700 million at the end of 1970 to more than $4 billion at the end of 1975.

The major impact of the regulatory lag on the industry's financial situation was that by the time the final order was issued to allow the applicant to increase rates, inflation had so eaten into the sum originally requested – this sum being

Table 2.12

Backlog of Electric Utility Rate Cases

End of Year	Total Dollar Value of Increases Granted During the Year (Million current $)	Number of Rate Cases Pending at End of Year	Total Dollar Value of Requested Increases Pending at End of Year (Million current $)
1970	534	59	679
1971	825	99	1,157
1972	870	99	1,123
1973	1,084	137	1,656
1974	2,202	183	4,015
1975	3,095	185	4,073

Source: Edison Electric Institute.

calculated based on costs prevailing at the time of application — that the rate increases finally granted were insufficient to cover inflated costs. This impact sometimes was mitigated by a commission's granting an interim rate increase while deliberations proceeded on the application itself. However, for over three-quarters of the cases decided during the period 1971-1973, no interim increases were granted.

Another way to mitigate the financial effects of regulatory lag and inflation is to permit so-called "forward-looking test years" to be used to calculate the amount of costs needed to be recovered through rate increases. This method of calculation permits applicants to anticipate cost trends, but has not been widely used in regulatory hearings.

The utilities' financial condition over the past decade is described in more detail in the next section, with particular attention to the utilities' future capital requirements and their attendant costs.

2.6 FINANCIAL CONSIDERATIONS

There are several important factors that have contributed to the electric utility industry's financial condition. This section will examine briefly these factors and then examine the relationship between these factors to the industry's financial condition. Chapter 3 presents a more detailed discussion of financial issues related to changes in environmental regulations facing the industry.

Because a sizable number of requests for rate relief were not acted upon immediately in recent years, as described above, it has become evident that the costs the industry incurred would have to be carried, at least for a time, by some other means. Since fixed charges, such as interest payable on debt, could not be reduced, the major source of funds has been cash flow from operations.

Clearly, the regulatory delays that had worked to the industry's and its investors' advantage in the early 1960s were working in the 1970s to their disadvantage. Whereas, in the early 1960s the industry's members were generally able to earn more than the rate of return allowed by regulatory commissions, in the early 1970s they were generally earning less. Table 2.13 illustrates that in 1970, 53 percent of privately owned utilities had higher than an 11 percent return on common equity, whereas in 1975 only 48 percent of the utilities realized that return.

One direct impact of a declining rate of return in the face of a greater need for funds was that the industry was forced to become much more dependent on capital markets, i.e., on external financing. When funds from internal sources – earnings, depreciation and tax deferrals – constitute relatively little to the firm's total investment needs, the utilities have had to acquire external funds in the capital market. Table 2.14 shows the significant extent to which the industry has been required to finance itself externally. External financing was required in particular in 1974 when sufficient internal funds were not available.

Table 2.15 shows that both long term debt and preferred stock holdings have increased, as a percent of the utilities capitalization between 1965 and 1975; long-term debt increased from 51.5 percent to 53.3 percent in 1975 (representing $70.8 billion); preferred stock increased from 9.5 percent ot 12.4 percent in 1975 (representing $16.8 billion issued. The average debt cost increased from 3.80 percent to 6.83 percent between 1965 and 1975, a very significant change over a period when utilities were financing a larger amount of their capital needs through debt, as indicated by the increased long-term debt as a percentage of net utility plant. Also indicative of the utilities' changing external financing patterns is that common stock holdings decreased as a percentage of capitalization from 27.5 percent in 1965 to 24.0 percent in 1975.

This discussion has highlighted the economic and financial trends that the electric utility industry has faced over the past ten years. Appendix A discusses

Table 2.13

Distribution of Returns on Equity for Class A & B Utilities, 1970 and 1975
(Percent of Utilities Earning Indicated Return)

Return on Equity	1970	1975*
Less than 5.00%	2.4%	5.7%
5.00 - 7.99	17.9	14.8
8.00 -10.99	27.1	31.0
11.00 -13.99	32.3	37.1
14.00 -16.99	16.4	9.5
17.00 and above	3.9	1.9

Source: Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States

* Includes equity earnings on subsidiary companies.

Table 2.14

External Financing of Electric Utility Industry, 1965-1975

Year	Percent of Investment Financed Externally	Year	Percent of Investment Financed Externally
1965	45%	1971	79%
1966	59%	1972	68%
1967	58%	1973	70%
1968	76%	1974	92%
1969	68%	1975	82%
1970	80%		

Sources: from Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry.

Table 2.15

Balance Sheet Relationships for Privately Owned Electric Utilities, 1965-1975

	1975	1974	1973	1972	1971	1970	1969	1968	1967	1966	1965
Percent of Capitalization:											
Long-term debt	53.3%	53.0%	52.3%	53.1%	54.2%	54.8%	54.6%	53.8%	53.0%	52.3%	51.5%
Preferred Stock	12.4	12.2	12.1	11.8	10.7	9.8	9.4	9.6	9.6	9.5	9.5
Common Stock and other paid in capital	24.0	23.5	23.8	23.5	23.3	23.2	23.4	24.1	25.2	26.1	27.5
Retained earnings	11.3	11.3	11.8	11.6	11.8	12.2	12.6	12.5	12.2	12.1	11.5
Long-term debt as percent net utility plant	51.5	51.4	50.2	51.3	52.2	52.5	51.9	51.6	51.4	50.6	49.7
Accumulated provision for depreciation as percent of total utility plant	20.3	20.2	20.4	20.7	21.3	21.9	22.4	22.7	22.9	23.0	22.7
AFDC as percent of net income	26.5	28.9	24.8	24.2	21.1	17.3	12.6	9.2	6.4	4.6	5.6
Average debt cost	6.83	6.32	5.80	5.51	5.27	5.01	4.52	4.17	3.94	3.81	3.80

Source: Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States in more detail the capital market environment which the electric utilities will face over the next ten to fifteen years as they find it necessary to finance their investment requirements. The remaining chapters will provide more detailed analysis of the economic and financial impacts on the industry and its customers as a result of alternative New Source Performance Standard revisions.

3.0 ECONOMIC AND FINANCIAL IMPACT ASSESSMENT OF ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS

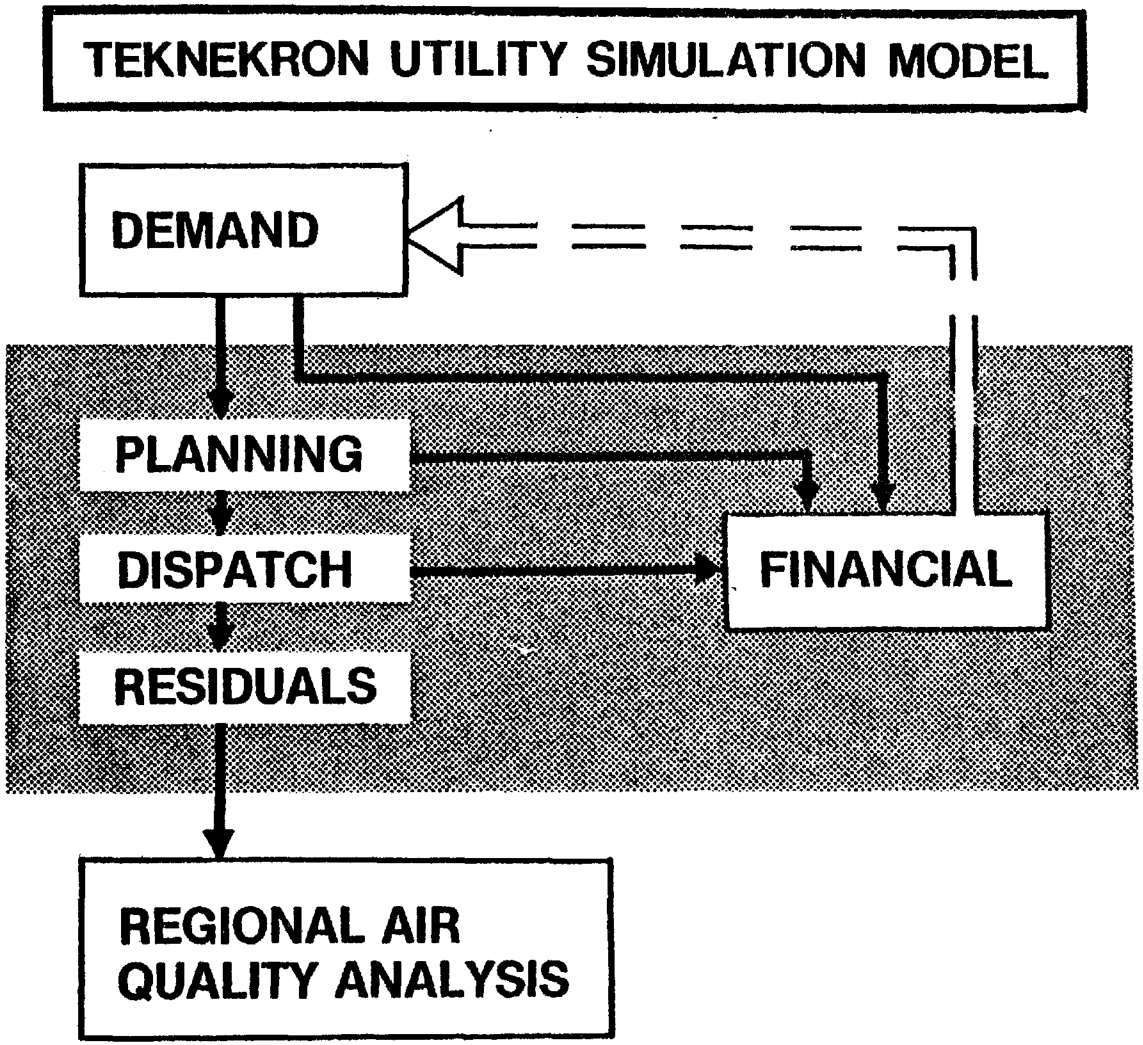
In this chapter the economic and financial effects of the alternative New Source Performance Standard (NSPS) shown in Table 1.1 will be assessed. The principal analytical means of examining these impacts is Teknekron's Financial module of its Utility Simulation Model (USM), which is described below. The Financial module works in conjunction with the other modules of the USM, as shown in Figure 3.1, so that the economic and financial impact results are fully consistent with the technical and environmental assessments discussed in Volumes I and III of this report.

In this chapter, "economic" impacts focus on changes in retail prices and electric utility expenses induced by revisions in NSPS at the national and regional levels. "Financial" impacts include those that may affect the relative financial position of the electric utilities. Also examined will be the relative impact of alternative NSPS revisions on the utility industry's external capital needs and, thus, on the nation's capital market. As with many types of forecasts, it is more important to consider the relative effects of these revisions rather than their absolute levels.

Several qualifications need to be made before commencing this examination. First, this analysis will not attempt to identify and compare the largely non-quantifiable private and social benefits that may be realized from revision of the NSPS. Such potential benefits may include improvements in human health, labor productivity, agricultural sector output, and visibility, along with a general improvement in social welfare.

Second, as is true for any forecast of future events, uncertainty surrounds our projection of the relative economic and financial impacts. We believe, however, that the Financial module, operating in conjunction with the rest of the Utility Simulation Model, has generated as useful, comprehensive information about the

Figure 3.1


TEKNEKRON UTILITY SIMULATION MODEL
DEMAND
PLANNING
DISPATCH
RESIDUALS
FINANCIAL
REGIONAL AIR
QUALITY ANALYSIS

potential impacts of NSPS revisions as can be obtained. The principal assumptions of the Financial module are discussed below in Section 3.1.1. The USM is discussed in the Appendix to Volume I.

Uncertainty also surrounds those estimates for a different reason. In the future some State Implementation Plans (SIPs) may require local standards more stringent than the Federal New Source Standards. Under such conditions, the economic and financial impacts ascribed to the federal standards may more properly be assigned to the state regulations. Although we have anticipated that certain current SIPs are, or are expected to be, more stringent than the current NSPS, we have assumed that the <u>revised</u> NSPS will apply uniformly to all coal-fired units operating in 1983 and thereafter.

Third, as will be discussed in the text, there are several regulatory agencies besides the state and federal environmental agencies that influence utility operations and performance. State Public Utility Commissions, and in the case of publicly owned utilities, utility district or local regulators, exert predominant authority over the utility's financial position. As its name implies, the rate-of-return regulation practiced by the State PUCs and the Federal Energy Regulatory Commission* over the electric utilities establishes an "allowed" rate of return for the utility. This return and the utility's performance then directly influence the firm's ability to raise capital. Federal environmental regulations are but one of several that the utilities face in their interactions with the nation's financial markets. As will be shown, pollution control investments made by the utility industry as a result of state and federal environmental regulations are growing, but still represent a small fraction of the industry's capital requirements over the next two decades. The utilities' ability to raise this capital is affected above all by state PUC policies and practices. Teknekron's Financial module makes reasoned assumptions, similar to other such financial models, about the responsiveness of the State PUCs to the utilities' financial needs. These assumptions are described below in Section 3.1.1.

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* Formerly the Federal Power Commission.

3.1 TEKNEKRON'S ELECTRIC UTILITY FINANCIAL MODULE

The Teknekron electric utility financial module, which has been developed over the past three years, provides economic and financial information to complement the wealth of technical and environmental data produced by other modules of the Utility Simulation Model. Table 3.1 presents the inputs that are passed to the financial module from other modules. The Financial module uses this information as well as internal computations for interest, depreciation, taxes, financing and rate-setting to produce annual simulated financial statements. These financial statements include an income statement, balance sheet, source and use of funds statement and other financial statistics for both investor owned and publicly owned electric utilities.

As is shown in Figure 3.1, the Financial module acts as an interface of the demand and supply models by means of a computational module which calculates prices at which revenues are in balance with costs. It constitutes a type of computer simulation of regulatory control. But, strictly speaking, a computer simulation of the regulatory process is impossible. Computer simulation implies that prices are determinable from cost information, or similar data, by definite mathematical formulas. This is often not the case. Rather, the regulatory commissions (or similar public regulatory authorities) are deliberative bodies. They consider a wide range of facts and hear opposing views expressed in the form of a formal hearing. In making their judgments they may be called upon to resolve problems when accepted principles are in conflict.

3.1.1 Financial Module Assumptions

This conceptual model, like other similar regulatory models,* involves a number of assumptions and approximations. It entails a uniformity of approach to regulation which does not, of course, exist among the many public bodies

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* For example, see P. L. Joskow and M. L. Baughman, "The Future of the U.S. Nuclear Energy Industry," Bell Journal of Economics, Spring 1976, pp. 3-32.

Table 3.1

Input Values Passed to the Financial Module by Other USM Modules

DEMAND INFORMATION	from **DEMAND**
• Sales to ultimate consumers	
• Sales for resale	
OPERATING DATA	from **DISPATCH**
• Fuel Expense	
• Operation Expense	
• Maintenance Expense	
PLANNING DATA	from **PLAN**
• Cash outlays for plant construction for each year of simulation	
• Details of plants coming online	
(All information broken down by asset categories)	

involved. The institutional complexities surrounding the regulatory process set limits on the analysis which can be made using the regulatory model.

The conceptual model of regulatory control assumes fundamentally that regulation acts to set prices so that revenue collected will equal actual costs of providing service. These costs are to be understood to include an appropriate return to investor/owners of the utilities. Prices so set are adjusted among different groups of customers in accordance with criteria of fairness to both consumers and investors; efficiency of resource management; insuring adequacy and reliability of future supply; and similar desirable attributes of an ideal pricing-regulatory system. The following are several of the principal assumptions incorporated into the operation of the Financial module.

<u>Constancy of current parameter values and accounting and tax practices.</u> The Financial module is required to make implicit assumptions regarding the external financial environment of the electric utility industry over the simulation period. A key assumption in this regard is that conditions will either remain as they are today or closely follow the historical pattern that has developed over the past 20 years. The model uses a predetermined external financing mix throughout the simulation period; the inflation rate, specified by the EPA, remains a constant 5.5 percent; the target return to investors on common equity is 13 percent. It is implicitly assumed that accounting practices and income-tax determination regulations will remain the same as they are now. The model has been updated for all current changes in tax laws and accounting procedures.

<u>Cost of capital is constant at all financing levels.</u> Just as the financing mix ratios are predetermined, the cost of capital is set at an exogenuously determined level for each type of security. This cost then remains constant throughout the model and all new issues of debt and equity will pay the specified return. It should be noted that in the case of common stock, because of well-known forecasting difficulties, no attempt is made to predict the market price of

the stock or earnings per share. Thus dividends are based on a specified percentage return for each dollar of common stock outstanding and are not determined on a per share basis.

Rate-setting Environment. The Financial module assumes a responsive rate-setting environment. Revenues in any given year are a result of an average electricity price determined in the previous year. This average price is based upon what revenue requirements would have been in effect in that year in order for the utility to recover all its costs and an allowed return to common stockholders. Because annual electricity demand growth rates are exogenously specified, there is an implicit assumption that price sensitivity and customers' substitution of energy forms due to relative energy prices are not significant factors. Although it is possible that during the simulation a return greater or less than the allowed return will actually result, due to fluctuations in the real cost of electricity and variations in financing levels, over the simulation period the realized rate of return will not vary dramatically from the allowed return specified.

Neutral effect of non-electric operations. A number of items on an electric utility's balance sheet and income statement are outside the scope of electric operations but nonetheless must be accounted for. These items include net income from non-electric operations, non-operating income, non-income taxes, other assets and other credits. The initial amounts of these items are determined from FPC forms, for 1975. During each year of the simulation they are assumed to increase at the inflation rate.

3.1.2 Regionalization

Throughout this assessment, when warranted, we will be examining important economic and financial impacts on a regional as well as national basis. The regions we have examined are basically those defined by the Bureau of Census, with one exception. In order to gain more insight into the economic and financial

Table 3.2

Regions Used for Analysis of Alternative NSPS Revisions

New England	Mid-Atlantic	South Atlantic	East North Central	East South Central
Connecticut	New York	Delaware	Wisconsin	Kentucky
Rhode Island	Pennsylvania	Maryland/D.C.	Michigan	Tennessee
Massachusetts	New Jersey	Virginia	Illinois	Mississippi
New Hampshire		West Virginia	Indiana	Alabama
Vermont		North Carolina	Ohio	
Maine		South Carolina		
		Georgia		
		Florida		

West North Central	West South Central	North Mountain	South Mountain	Pacific
North Dakota	Texas	Idaho	Nevada	Washington
South Dakota	Oklahoma	Montana	Utah	Oregon
Nebraska	Arkansas	Wyoming	Colorado	California
Kansas	Louisiana		Arizona	
Iowa			New Mexico	
Missouri				
Minnesota				

effects on the utility industry in the western United States, we have subdivided the Census' Mountain region into two regions, North Mountain and South Mountain. The regions are defined in Table 3.2.

3.2 ECONOMIC IMPACTS

The economic impacts associated with changing pollution control regulations for electric utility coal-fired boiler operations can be examined from several perspectives. First, we will analyze the economic effects on the utility industry; including changes in its total revenue requirements; total costs and important components, such as fuel, operation and maintenance and pollution control equipment O&M; net profit and capital investment needs, both for plant and pollution control equipment. These effects will then be compared across the selected NSPS revisions. See Table 3.3 for a description of the alternative NSPS revisions considered.

Second, we will then compare the impact on retail prices under several of the scenarios defining alternative NSPS revisions. These prices will be examined both nationally and regionally, to capture important regional detail. After this we will analyze the per capita cost of the revisions. This measure is important when one assumes that cost increases facing industrial and other utility customers ultimately can be passed forward to the residential consumer.

Third, we will examine the national and regional pollution control costs and investment expenses associated with alternative NSPS revisions. As will be shown, it is important to show regional data as there can be significant variations among regions, illustrating differences in the characteristics of their electricity supply systems, economic factors and fuel availability and cost.

3.2.1 Economic Impacts on the Utility Industry

Revisions to the NSPS may have several, inter-related effects on important economic parameters facing the electric utility industry over the 1976-1995 time

Table 3.3

Alternative New Source Performance Standard Revisions Considered

Electricity Demand Growth	BASELINE M 1.2(0)0.1 Moderate*	M 1.2(90)0.1 Moderate*	M 1.2(80)0.03 Moderate*	M 1.2(90)0.03 Moderate*	M 0.5(0)0.03 Moderate*	BASELINE H 1.2(0)0.1 High+	H 1.2(90)0.1 High+	H 1.2(80)0.03 High+	H 1.2(90)0.03 High+
Ceiling for SO_2 Emissions**	1.2	1.2	1.2	1.2	0.5	1.2	1.2	1.2	1.2
Percent Removal Requirements for SO_2	0	90%	80%	90%	0	0	90%	80%	90%
Particulate Standard**	0.1	0.1	0.03	0.03	0.03	0.1	0.1	0.03	0.03

* 5.8% per year to 1985; 3.4% thereafter.

** In $lb/10^6$ Btu

\+ 5.8% per year to 1985; 5.5% thereafter.

NOTE: Standards other than the baseline cases are assigned to apply only to coal-fired generating units beginning commercial operation in 1983 or later. See Volume I for a more detailed discussion of the scenarios analyzed.

period. We have focused on the ten-year period 1986-1995 since we assume that plants subject to the revised NSPS will not be coming on-line until 1983. See Volume I for a more detailed discussion.

Tables 3.4 and 3.5 present the forecasted national changes in the following economic factors for the moderate and high demand growth rates, respectively:*

- Total Revenue Requirements;
- Total Cost;
- Fuel Cost;
- Operation and Maintenance Cost;
- Pollution Control Cost;
- Net Profit;
- Total Investment Excluding Pollution Control
- Pollution Control Investment; and
- Retail Price.

These represent the principal economic factors facing the electric utility industry that may be affected by a revision of the NSPS.

3.2.1.1 Total Revenue Requirements

As is shown in Table 3.4, total revenue requirements under moderate growth vary little as a result of the NSPS revisions considered. The largest increase over the current standard (baseline, M 1.2(0)0.1) occurs with the 90 percent removal with 12.9 ng/J (0.03 lb/10^6 Btu) particulate limit. Under this case total revenue requirements, which include a target return on equity (or the rate base in the case of the publicly owned utilities), increase $24 billion over the 1986-1995 time period, representing about a 2 percent increase over baseline. All of the other

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* Throughout this assessment all forecasted dollar values are presented in 1975 dollars.

Table 3.4

Comparison of Selected National Economic Impacts on the Electric Utility Industry of Alternative NSPS Revisions*

1986 - 1995

	Baseline M 1.2(0)0.1	M 1.2(90)0.1	M 1.2(80)0.03	M 1.2(90)0.03	M 0.5(0)0.03
Total Revenue	$1,149.5	+22.1**	+20.9**	+24.0**	+20.5**
Total Cost	1,023.9	+26.7	+25.8	+29.0	+25.5
Fuel	369.8	-0.3	-0.3	0	-0.9
Operation & Maintenance	167.4	+0.5	+0.5	+0.6	+0.5
Pollution Control+	36.4	+7.2	+6.9	+7.9	+7.0
Net Profit	125.6	-4.6	-4.9	-5.0	-5.0
Total Investment Excluding Pollution Control	325.3	+4.2	+3.1	4.2	+3.4
Pollution Control Investment +	8.0	+13.0	+13.3	+14.6	+13.3

	Baseline 1985	Baseline 1995	M 1.2(90)0.1 1985	M 1.2(90)0.1 1995	M 1.2(80)0.03 1985	M 1.2(80)0.03 1995	M 1.2(90)0.03 1985	M 1.2(90)0.03 1995	M 0.5(0)0.03 1985	M 0.5(0)0.03 1995
Retail Price (1975¢/kWh)	2.81	2.93	+0.04	+0.05	+0.03	+0.05	+0.04	+0.05	+0.03	+0.05

* Unless noted otherwise, figures in billions of 1975 dollars.

** Change from baseline.

\+ Includes expenses for SO_2, NO_x, particulate and water pollution controls. The latter are not varied across scenarios.

Table 3-5

<u>Comparison of Selected National Economic Impacts on the Electric Utility Industry of Alternative NSPS Revisions*</u>

1986 - 1995

	Baseline H 1.2(0)0.1	H 1.2(90)0.1	H 1.2(80)0.03	H 1.2(90)0.03
Total Revenue	$1,346.1	+41.0**	+42.5**	+47.8**
Total Cost	1,197.1	+52.9	+54.3	+60.7
Fuel	432.6	+ 2.6	+ 2.7	+ 5.1
Operation & Maintenance	196.1	+ 1.0	+ 0.8	+ 0.6
Pollution Control+	40.0	+14.9	+11.1	+16.3
Net Profit	140.0	- 2.9	- 2.8	- 3.9
Total Investment Excluding Pollution Control	518.8	+ 5.4	+ 4.3	+ 5.5
Pollution Control Investment +	17.6	+30.7	+30.1	+34.4

	Baseline 1985	Baseline 1995	H 1.2(90)0.1 1985	H 1.2(90)0.1 1995	H 1.2(80)0.03 1985	H 1.2(80)0.03 1995	H 1.2(90)0.03 1985	H 1.2(90)0.03 1995
Retail Price (1975 ¢/kWh)	2.85	3.10	+0.05	+0.13	+0.05	+0.11	+0.05	+0.16

* Unless noted otherwise, figures in billions of 1975 dollars

** Change from Baseline

\+ Includes expenses for SO_2, NO_x, particulate and water pollution controls. The latter are not varied across scenarios.

revenue changes for other revisions, including moving to a 215 ng/J (0.5 lb/10^6 Btu) SO_2 ceiling result in less than 2 percent increases in total revenue requirements.

Under the high growth cases, total revenue requirements increase more. Again, the largest increase occurs under the 90 percent, 12.9 ng/J (0.03 lb/10^6 Btu) case; where revenues increase over $47 billion, representing a 3.6 percent increase. Each of the other revisions results in increases of about 3 percent.

Thus, the NSPS revisions considered are not forecast to increase total revenue requirements significantly between 1986 and 1995.

3.2.1.2 Costs

Total Costs include the following items;

- Fuel,
- Operation and Maintenance,
- Pollution Controls,
- Income Taxes,
- Other Taxes,
- Interest Expense,
- Depreciation and
- Other Utility Costs.

We have selected fuel, operation and maintenance (O&M) and pollution control costs as the most important operating costs of the above cost categories and have focused our attention on them. Under the baseline case in both moderate and high growth, these three cost categories are forecast to comprise over 55 percent of total costs between 1986 and 1995. The largest is fuel cost, representing 36 percent of total costs; the smallest of these categories is pollution control costs, representing somewhat over 3 percent of total costs.

As will be shown, some cost categories increase substantially under the NSPS revisions. Under moderate growth, as shown in Table 3.4, total costs increase the most, \$29 billion, under the 90 percent SO_2 removal case and a particulate limit of 12.9 ng/J (0.03 lb/10^6 Btu). This would be expected because this represents the most stringent NSPS revision we have considered. Putting this in perspective, however, this change represents less than a 3 percent increase in total costs. The high growth cases, presented in Table 3.5, show that the dollar increase in total costs rise considerably, due mostly to the relatively higher costs of building, operating and maintaining an electric utility system capable of meeting this increased load.

The largest increase in total costs for the high growth cases (Table 3.5) is found for the 90 percent 12.9 ng/J (0.03 lb/10^6 Btu) case; a \$60.7 billion increase. This represents a 5.1 percent increase in total costs. Each of the other cases shows between a 4 and 5 percent increase in total costs, over the ten-year period.

Under the moderate growth cases fuel costs remain essentially constant as illustrated in Table 3.4. Each of the incremental changes are well within the margin of uncertainty for the fuel price data used and represent less than one-quarter of one percent change. Similarly, the O&M costs do not change significantly across the alternative NSPS revisions.

The fuel costs increase slightly under the high growth cases. The largest change, \$5.1 billion, shown in Table 3.5 represents a 1.2 percent increase over the ten-year period examined and should not be considered a significant change. Operation and Maintenance costs also do not increase significantly; the largest change, \$1 billion, is but a 0.5 percent increase.

Pollution control costs, which represent not only operation and maintenance expenses for SO_2 control equipment, but for NO_x, particulate and related control equipment, increase significantly under the NSPS revisions.* The largest

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* As mentioned previously, pollution control costs include the costs of meeting water pollution regulations. However, since these regulations are held constant, their effect is removed when we examine the incremental costs of more stringent NSPS. Appendix B describes how SO_2 and particulate costs can vary for a typical generating unit based on fuel type and its physical characteristics.

increase shown in Table 3.4 occurs under the 90 percent SO_2, 12.9 ng/J (0.03 lb/10^6 Btu) particulate case, \$7.9 billion over the ten-year period, and represents just under a 22 percent increase. The other cost increases range between 19 and 20 percent for other NSPS revisions.

Imposition of the 90 percent SO_2 removal requirement, as compared to 80 percent does not appear to markedly increase pollution control costs. If these additional costs, \$1 billion (\$7.9 - \$6.9), are spread evenly over the period examined, they represent less than 0.5 percent annual increase in total costs. A similar result is that tightening of the particulate standard does not appear to result in a significant cost increase, less than 0.2 percent annual change over the ten-year period.* Although pollution control costs increase significantly, as a percent of total costs, they increase from 3.6 percent to 4.2 percent. When put in the perspective of total costs the increase appears more tempered.

Under the high growth cases, shown in Table 3.5, pollution control costs increase more, as expected. The largest growth occurs under the 90 percent 12.9 ng/J (0.03 lb/10^6 Btu) case, when over the ten-year period these costs increase \$16.3 billion. This represents over a 40 percent increase in these costs. Other cost increases range between 27 and 37 percent.

As was found in the moderate growth cases, the imposition of the 90 percent SO_2 removal standard, as compared to the 80 percent standard, is forecast to have a marginal effect on pollution control costs. If spread evenly ovear the ten-year period, the stricter standard would increase annual total costs by less than 0.5 percent. In addition, annual total costs do not increase significantly, less than 0.4 percent, where the particulate standard is tightened to 12.9 ng/J (0.03 lb/10^6 Btu).

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* This conclusion may be different if precipitators, rather than fabric filters had been used for Western coal; See Volume I.

In Section 3.3.2.3, we will discuss the regional effects of these pollution control cost increases.

3.2.1.3 Net Profits

The imposition of alternative NSPS revisions is forecast uniformly to decrease the electric utility industry's net profits,* defined as total revenues minus total costs. The decreases as a percentage of baseline are greatest under the moderate growth cases as shown in Table 3-4. Net profits decrease over 20 percent under scenario M1.2(90)0.03, in part due to the one year regulatory lag assumed in the model in covering increased costs. Because of relatively lower revenue growth under the high growth cases, net profit reductions are much less and do not exceed 3 percent over the ten year period. Generally, the more stringent the NSPS revision, the greater net profits drop, as would be expected. More detailed analysis of the financial effects of NSPS revisions, including return on equity and quality of earnings, is presented in Section 3.3.

3.2.1.4 Investment

The NSPS revisions are projected to influence both total investment excluding pollution control, representing principally plant investment, and pollution control investment. As presented in Tables 3.4 and 3.5, total investment excluding pollution control increases with the NSPS revisions.

In addition to the direct pollution control investment expenditures that the utility industry is forecast to make the industry also will face somewhat higher plant investment expense due to the capacity penalties incurred with operation of FGD systems. These penalties have been estimated to be between five and six

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* Net profits is used for both privately and publicy owned utilities although, technically, publicly owned utilities' account would be called a "surplus."

percent for installed generating capacity.* From this information and from the simulation model's national forecast of the percent of capacity using FGD systems in 1995, we estimate that approximately $2.7 billion (in 1975 dollars) may be required for additional plant investment due to capacity penalties under the moderate growth case (M1.2(90)0.03); under the high growth case (H1.2(90)0.03), as much as $4.8 billion may be necessary. These additional, indirect pollution control investment expenditures are accounted for, although not explicitly, in the incremental changes in Total Investment Excluding Pollution Control category shown in Tables 3.4 and 3.5. The incremental investment, however, is a small percentage increase over the baseline. The largest increase under moderate growth, $3 billion, represents 0.6 percent. Under high growth the largest increase over the ten-year period is $4.2 billion, representing 1.3 percent increase over the baseline.

Pollution control investment increases significantly, as expected. It should be remembered, however, that such investment represents a relatively small part of the industry's forecasted capital investment needs over the 1986-1995 period. Under the moderate growth baseline, pollution control investment represents 2.4 percent of total investment. For the high growth baseline, it represents 3.4 percent ot total investment.

The increases in pollution control investment for the moderate growth cases range from $13 to $14.6 billion over the 1986-1995 period, representing between a 62 and 83 percent increase over baseline. The largest increase for each growth rate is found under the M1.2(90)0.03 scenario, as expected. As is described in more detail in Volume I, the amount of national coal capacity subject to FGD in 1995 increases from 16 and 13 percent to 51 and 68 percent for the moderate and high growth cases, respectively. Pollution control investment, as a percent of total investment, increases to 6.9 and 10 percent under the moderate and high

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* See "Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers," PEDCo Environmental, Inc. under EPA Contract 68-02-2535.

growth rates, respectively. Since the regional distribution of this additional pollution control investment can have important implications, the regional effects are examined in Section 3.2.3, below.

3.2.1.5 Retail Prices

National average retail prices for each of the NSPS revisions considered are found not to have significant variation in 1985. By 1995, only the high growth cases shown significant variation. The largest change occurs with the 90 percent SO_2 removal 12.ng/J (0.03 lb /10^6 Btu) particulate limit, a 16 mill/kWh increase, representing a 5.2 percent increase over the baseline. These retail prices represent a weighted average of retail prices for privately and publicly owned utilities. Section 3.2.2 contains more detailed analysis of the regional price effects under alternative NSPS revisions.

3.2.2 Regional Prices and Per Capita Costs

Table 3.6 presents a detailed compilation of regional impacts on the utility industry's retail electricity prices in 1985 and 1995. The 90 percent SO_2 removal with the tightened particulate standard scenarios were chosen for moderate and high growth since these resulted in the largest change in national average retail prices (see Tables 3.4 and 3.5). In order to facilitate some comparison we have included the M0.5(0)0.03 scenario as well.

The regional variations can be large. The New England region is forecast to continue to have the highest retail prices under both moderate and high growth cases, over 40 percent greater than the national average in 1995. The East South Central region, which contains much of the Tennessee Valley Authority service territory, historically one of the least expensive areas for electricity, is forecast to change, on average, less than 50 percent of the national average by 1995.

Under both moderate and high growth scenarios, the largest increase in retail prices in 1995 occurs in the West South Central region. Consumers there bear

Table 3.6

Regional Price Impacts on the Electric Utility Industry of Alternative NSPS Revisions, 1976-1996

	Baseline M 1.2(0)0.1		M 1.2(90)0.03		M 0.5(0)0.03		Baseline H 1.2(0)0.1		H 1.2(90)0.03	
REGION	1985	1995	1985	1995	1985	1995	1985	1995	1985	1995
NATION	2.81*	2.93*	1.4**	1.7**	1.1**	1.7**	2.85*	3.10*	1.8**	5.2**
New England	3.90	4.23	0.3	1.7	0.0	1.7	3.96	4.31	0.3	0.2
Mid-Atlantic	3.76	3.58	1.3	2.0	1.3	2.0	3.81	3.83	0	2.1
South Atlantic	2.86	3.03	1.7	1.7	1.7	1.7	2.90	3.27	2.1	4.6
East North Central	2.99	3.11	-0.7	0.3	-0.7	-0.3	3.01	3.32	2.0	4.8
East South Central	1.43	1.32	1.4	2.3	0.7	2.3	1.45	1.42	2.7	2.8
West North Central	2.77	2.73	0	1.8	0.0	2.2	2.81	2.95	1.8	5.4
West South Central	2.15	2.92	3.3	11.0	3.3	4.1	2.17	2.91	3.7	12.0
North Mountain	2.30	2.02	0.4	3.5	0.4	1.5	2.29	2.30	0.8	7.4
South Mountain	2.67	2.67	5.6	3.7	4.9	0.4	2.76	2.91	4.0	1.7
Pacific	2.76	2.75	0.7	0.7	0.4	0.4	2.78	2.90	1.1	1.0

* Average prices to retail customers expressed in ¢/kwh, in 1975 dollars. Represents a weighted average of privately and publicly owned utilities.

** Percentage change from Baseline.

the largest price increase because of the projected phase-out of oil- and gas-fired capacity and replacement by coal capacity additons subject to the revised standards (see Volume I, Table 2.5). Other regions that reflect relatively higher price increases are the two Mountain regions, where the revisions would cause a shift from new source compliance through the use of low sulfur coals to the use of FGD systems.

Changes in the percentage increases between 1985 and 1995 illustrate the distribution of economic effects over time and system expansion schedules. Price changes in 1985 do not reflect major impacts of the NSPS revisions since the revisions only affect capacity on-line after 1983. What effects are present reflect in large part the price-related additional investment expenditure impacts for generating equipment construction underway. The West South Central region's prices increase significantly more in 1995; whereas, other regions such as Pacific, East South Central and South Atlantic reflect a more balanced increase in prices over the period. Several regions such as South Mountain show less price increase in 1995 than in 1985 and illustrate that by the last year of the forecast much of the price-related effects have been accounted for. The 1985 price change for East North Central under moderate growth appears negative. However, the change should be interpreted as not significantly different from zero, since it is within the forecast's margin of uncertainty. Overall, the price changes resulting from NSPS revisions do not appear to be large by 1995, with the exception of the Gulf Coast region as previously noted.

Under moderate growth the 215 ng/J (0.5 lb/10^6 Btu) SO_2 ceiling case, the M0.5(0)0.03 scenario, is notable in that there is relatively little difference in 1995 retail prices between it and the 90 percent SO_2 removal scenario. Under this scenario, however, the West South Central and North Mountain regions' price increases in 1995 are less than half than those under the 90 percent SO_2 cases.

Another useful measure of economic impact on the consumer is the relative change in per capita costs, here defined as total revenue requirements divided by population in 1995, are presented in Tables 3.7 and 3.8 for the moderate and high growth cases respectively. The growth of real per capital cost between 1976 and 1995 is not dramatic. In 1976, the model estimates that national real per capita cost is \$268; by 1995 it increases to over \$500 and over \$600 for the moderate and high growth baseline cases respectively. There are several reasons for this increase. The yearly demand growth rates we have assumed require the utility industry to build new capacity to meet these projected loads with ever more expensive generating capacity, transmission lines and distribution systems. The compound effect of cost escalation and demand growth rates that exceeds the population growth rate increase (about one percent per year) increases the total costs of operating, maintaining and financing the nation's utility systems. As costs increase, revenue requirements correspondingly increase. Retail prices have been shown not to increase greatly (see Table 3.6), so that increased revenue requirements are satisfied principally by the constant growth in kWh sales.

The important information presented in Tables 3.7 and 3.8 is the incremental change in per capita costs between scenarios rather than the absolute level of these costs. As is shown, none of the moderate growth cases shows a large increase in per capita costs. The largest national increase occurs under the most stringent scenario, M1.2(90)0.03; but this represents less than a 2 percent change in per capita costs over the baseline. Under the high growth cases the increase is larger, \$27 in 1995, representing almost a four percent increase in per capita costs.

It is important to note the regional variations in per capita costs. The biggest increases in per capita costs occurs in the Gulf Coast region, West South Central, where the largest percentage of new FGD capacity is built. The largest increase for this region under moderate growth, \$35, represents a 6 percent change in per capita cost. The next largest change occurs in the North Mountain region, where per capita costs increase 5.1 percent. Each of the other changes represents less than a 3 percent increase.

Table 3.7

Per Capita Cost of Alternative NSPS Revisions, 1995*

Region	Baseline M 1.2(0)0.1	M 1.2(90)0.1	M 1.2(80).03	M 1.2(90).03	M 0.5(0).03
Nation	$530	+$ 8+	+$ 8+	+$ 9+	$+ 7+
New England	476	+ 8	+ 1	+ 8	+ 8
Mid-Atlantic	469	+ 5	+ 5	+ 7	+ 6
South Atlantic	576	+ 5	+ 6	+ 7	+ 7
East North Central	577	+ 3	+ 5	+ 3	+ 3
East South Central	365	+ 7	+ 7	+ 7	+10
West North Central	475	+ 6	+ 6	+ 6	+ 3
West South Central	662	+31	+29	+35	+25
North Mountain	426	+41	+38	+42	+25
South Mountain	462	+14	+11	+14	+ 1
Pacific	541	+ 7	+ 8	+ 7	+ 7

* Defined as total revenues divided by population in 1995. All figures in 1975 dollars.

\+ Change from Baseline.

Table 3.8

Per Capita Cost of Alternative NSPS Revisions, 1995*

REGION	Baseline H 1.2(0)0.1	H 1.2(80)0.03	H 1.2(90)0.03
NATION	$685	$+24+	$+27+
New England	632	0	0
Mid-Atlantic	609	+ 7	+12
South Atlantic	766	+36	+40
East North Central	747	+27	+33
East South Central	491	+13	+14
West North Central	629	+26	+30
West South Central	801	+80	+87
North Mountain	606	+45	+48
South Mountain	617	+ 1	+ 5
Pacific	677	+ 5	+ 6

* Defined as total revenues divided by population in 1995. All figures in 1975 dollars.

\+ Change from Baseline.

Under the high growth cases, the same regions again incur the largest increases, both above 7 percent as shown in Table 3.8. Also, the Mid-Atlantic, East North Central and West North Central regions are forecast to have relatively larger increases in per capita costs, both between 4 and 5 percent. Each of the other changes is under 4 percent.

To summarize, changes in both average retail prices and per capita costs under the various control scenarios are not forecast to be large at the national level. National price increases at most increase 5 percent in 1995. In that year, national per capita costs increase at most 4 percent, under the high growth case, and at most 2 percent under the moderate growth case.

Regional impacts display significant variation, with the West South Central region incurring the largest price and per capita cost increases; over 10 percent increase for both measures under high growth. Other more affected regions include North Mountain and the West North Central regions, where coal capacity additions using FGD systems are significant. Other regions analyzed are not forecast to be severely affected in terms of price or per capita cost as a result of alternative NSPS revisions.

On average, forecasted differences between the 80 percent and 90 percent SO_2 removal cases do not appear significant for either retail prices or per capita costs.

3.2.3 Regional Pollution Control Cost and Investment

One of the most important impacts on the electric utility industry of implementing more stringent NSPS will be changes in direct pollution control expenses, including both operation and maintenance costs and investment expenditures. We have previously discussed a third important cost, indirect pollution control-related expense, the cost of additional generating capacity needed due to capacity penalties incurred by using FGD systems (see Section

3.2.1.4). In this section we will examine the regional distribution of these direct costs and investment over the 1986-1995 period.

3.2.3.1 Regional Pollution Control Costs

We will concentrate our discussion on the regional impacts of the NSPS revisions on pollution control costs over the period 1986-1995. It should be remembered that when used, the term pollution control costs includes expenses for SO_2, NO_x and particulate pollution control equipment operation and maintenance.*

Tables 3.9 and 3.10 display the regional pollution control costs associated with alternative scenarios under moderate and high growth cases respectively. As is shown in the tables, the South Atlantic, Mid-Atlantic, East North Central and West South Central regions account for the largest percentage of pollution control costs in the baseline cases, representing 68 percent of the national total.

As expected, the largest increases in pollution control costs occurs in the West South Central region; for moderate growth, an 80 percent increase; for high growth, an 85 percent increase. Other large percentage increases occur in the Mid-Atlantic, North Mountain and Pacific regions. Increases for New England are less than $0.1 billion because of the nuclear and oil-fired generation in that region (see Volume I, Table 2.5). Finally, note that in all regions pollution control costs under the 80 percent SO_2 removal requirement and the 215 ng/J (0.5 lb/10^6 Btu) SO_2 emission limit scenarios are nearly identical.**

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* The costs of meeting chemical and thermal emission limitations promulgated by EPA in 1974 are included. However, these limits do not change among the scenarios.

** Although we have not run this last scenario under the high growth assumption, we do not anticipate that the results would contradict this conclusion.

Table 3.9

Pollution Control Costs by Region For Alternative NSPS Revisions*

1986 - 1995

Region	Baseline M 1.2(0)0.1	M 1.2(80)0.03	M 1.2(90)0.03	M 0.5(0)0.03
Nation	$36.4	+$6.9**	+$7.9**	+$6.8**
New England	0.9 (2.4)+	0	0	0
Mid-Atlantic	5.0 (13.7)	+0.3	+0.5	+0.5
South Atlantic	7.0 (19.2)	+1.9	+2.1	+2.0
East North Central	8.5 (23.3)	+0.3	+0.3	+0.3
East South Central	4.0 (11.0)	+0.1	+0.2	+0.1
West North Central	2.2 (6.0)	+0.4	+0.4	+0.3
West South Central	4.1 (11.2)	+3.0	+3.3	+2.9
North Mountain	0.3 (0.8)	+0.1	+0.1	+0.1
South Mountain	2.5 (6.8)	+0.3	+0.5	+0.2
Pacific	1.9 (5.2)	+0.5	+0.5	+0.5

* In billions of 1975 dollars, icnludes expenses for SO_2, NO_x, particulate and related pollution control equipment operation and maintenance costs.

** Change from Baseline.

+ Figures in parentheses indicate percent of national total; does not add to 100 due to rounding.

Table 3.10

Pollution Control Costs by Region For Alternative NSPS Revisions*

1986 - 1995

Region	Baseline H 1.2(0)0.1	H 1.2(80)0.03	H 1.2(90)0.03
Nation	$40.0	+$13.4**	+$16.3**
New England	1.1 (2.7)+	0	+0.1
Mid-Atlan	4.3 (10.8)	+2.6	+3.0
South Atlantic	8.0 (20.0)	+2.6	+3.1
East North Central	10.3 (25.8)	+2.2	+2.6
East South Central	3.8 (9.5)	+0.2	+0.5
West North Central	2.5 (6.3)	+0.8	+0.8
West South Central	4.6 (11.5)	+3.3	+3.9
North Mountain	0.3 (0.1)	+0.2	+0.4
South Mountain	2.7 (6.7)	+0.4	+0.5
Pacific	2.4 (6.0)	+1.2	+1.4

* In billions of 1975 dollars; includes expenses for SO_2, NO_x, particulate and related pollution control equipment operation and maintenance costs.

** Change from Baseline.

\+ Figures in parentheses indicate percent of national total; does not add to 100 due to rounding.

3.2.3.2 Regional Pollution Control Investment

We have discussed the national results on direct pollution control investment in Section 3.2.1.4 above; now we will examine the regional impacts on direct pollution control investment incurred under alternative NSPS revisions. Tables 3.11 and 3.12 present regional pollution control investment expenditures over the 1986-1995 time period.

As was in the case of pollution control costs, several regions dominate the industry's direct pollution control investment. The Mid-Atlantic, South Atlantic, East North Central and West South Central in both the moderate and high growth baseline cases account for over 65 percent of the national total throughout the period. In the moderate growth baseline case, the West South Central region incurs the largest percentage of direct pollution control investment. In the high growth baseline, the East North Central region, which contains the northern Ohio River Valley area, incurs the largest percentage of this investment expense, illustrating regional variances in demand growth and generating capacity additions.

Again, the largest increases occur under the 90 percent SO_2 removal, 12.9 ng/J (0.03 lb/10^6 Btu) case, although national and regional differences between the 90 percent and 80 percent SO_2 removal requirements, as presented in Table 3.11, do not appear significant for the 1986-1995 period. Regionally, the West South Central area incurs the largest increase, representing a 400 percent increase. As has been stated before, this Gulf Coast region is the most severely affected due to the utilities' movement away from gas-fired boilers to coal-fired capacity that will be subject to the revised standards. The South Atlantic, North Mountain and South Mountain regions also show substantial increases in their direct pollution control expenses. As before, we see that the M0.5(0)0.03 scenario shows nearly the same direct pollution control investment as the 80 percent SO_2 removal standard.

Table 3.11

Direct Pollution Control Investment by Region for Alternative NSPS Revisions*

1986 - 1995

Region	Baseline M 1.2(0)0.1	M 1.2(80).03	M 1.2(90).03	M 0.5(0).03
Nation	$8.0	+$13.3**	+$14.6**	+$13.3**
New England	0.5 (6.3)+	0	0	0
Mid-Atlantic	1.5 (18.8)	+0.8	+1.1	+1.1
South Atlantic	1.4 (17.5)	+2.2	+2.5	+2.5
East North Central	1.1 (13.8)	+0.4	+0.4	+0.4
East South Central	0.5 (6.3)	+0.7	+0.8	+0.8
West North Central	0.5 (6.3)	+1.4	+1.5	+1.3
West South Central	1.6 (20.0)	+6.1	+6.5	+6.0
North Mountain	0.1 (1.3)	+0.2	+0.3	+0.2
South Mountain	0.4 (5.0)	+0.8	+0.9	+0.7
Pacific	0.4 (5.0)	+0.4	+0.5	+0.4

* In billions of 1975 dollars; includes expenses for SO_2, NO_x, TSP and related pollution control.

** Change from Baseline.

\+ Figures in parentheses indicate percent of national total; does not add to 100 due to rounding.

Table 3.12

Direct Pollution Control Investment by Region For Alternative NSPS Revisions*

1986 - 1995

Region	Baseline H 1.2(0)0.1	H 1.2(80).03	H 1.2(90).03
Nation	$17.6	+$30.1**	+$34.4**
New England	0.9 (5.1)+	+0.1	+0.2
Mid-Atlantic	1.6 (9.1)	+3.5	+4.0
South Atlantic	2.8 (15.9)	+4.9	+5.5
East North Central	6.1 (34.7)	+5.3	+6.1
East South Central	0.7 (4.0)	+1.9	+2.2
West North Central	1.1 (6.3)	+3.1	+3.4
West South Central	2.7 (15.3)	+7.3	+8.3
North Mountain	0.2 (1.1)	+0.4	+0.5
South Mountain	0.5 (2.8)	+1.6	+1.8
Pacific	1.0 (5.7)	+2.0	+2.2

* All figures in billions of 1975 dollars; includes expenses for SO_2, NO_x, TSP and related pollution control equipment investment.

** Change from Baseline.

\+ Figures in parentheses indicate percent of national total.

Under the high growth cases presented in Table 3.12, the largest increase occurs in the West South Central region, as occurred in the moderate growth cases. The increase in direct pollution control investment for the Gulf Coast area is 300 percent under the 90 percent SO_2 removal case. Other regions where investment expenditures at least double include South Atlantic, East South Central, West North Central, North Mountain, South Mountain and Pacific. Because relatively little of its generating capacity is coal-fired, New England again stands out as being relatively unaffected.

As expected, we project large increases in the utility industry's direct pollution control investment, although it must be remembered that this increase represents a relatively small portion of the industry's forecasted total investment needs.

To summarize, both pollution control costs and direct pollution control investment increase significantly over the 1986-1995 period. As would be expected, investment expenditures increase more than costs. The largest increases occur under the 90 percent SO_2 removal 12.9 ng/J (0.03 lb/10^6 Btu) particulate limit cases, although we do not forecast large differences between the 80 and 90 percent SO_2 removal cases. The West South Central region is the most heavily affected, as its pollution control costs are forecast to increase at most 85 percent; this region's direct pollution control investment costs may increase as much as 300 percent. Under the high growth cases, six of the ten regions' direct investment costs at least double. Becase of its minimal dependence on coal-fired capacity, New England bears the smallest increase in these costs and investment.

3.3 FINANCIAL IMPACTS

In appraising the relative effects of alternative NSPS revisions, economic impacts, as have been discussed, can be shown as the result of a direct cause-and-effect relationship. That is, if an NSPS revision suggests that additional expenditures need to be made, then utilities will bear the added costs and consumers, higher prices. Financial impacts are more difficult to relate to the added capital expenditures implied by candidate new source performance standards. This is true for a variety of possible reasons. There is, in fact, no direct relationship between utilities' needs to incur additional costs and any measure of their financial well-being. A number of factors can intervene. The most important of these factors is regulatory treatment of the added expenditures and the stock market's interpretation of the financial impact of the added cost burden. Investors, in making these interpretations, will take into account such matters as regulatory recognition of possible financial impacts, consumer responses to higher prices, possible flexibility in the overall capital spending plans of utilities, perceptions as to the phase of the business cycle in which capital spending may take place, the perspectives and activities of other market participants, and the management philosophies and overall financial health of the affected utilities. It is impossible to take all such factors into account. However, by making certain behavioral assumptions in the Utility Simulation Model, it is possible to demonstrate the relative effect of alternative NSPS revisions on several generally accepted measures indicative of financial well-being.

The financial health of the electric utility industry may be represented by such measures as its return on equity, its interest coverage ratio, and the quality of its earnings. The return on equity, as used in this report, refers to a realized book return on equity investment. It encompasses both cash and noncash earnings. The interest coverage ratio refers to the relationship between earnings and interest payable on debt. The ratio is calculated by adding earnings to interest payments, and dividing this sum by interest payments. This ratio is significant because bond indenture agreements are generally written so as to prohibit additional debt financing in the event the interest coverage ratio falls below a certain level, usually 1.75:1 or 2:1. The final measure, quality of earnings, shows the extent to which a current year's earnings are made up of noncash credits to income. These credits are placed in an account termed the Account for Funds used During Construction (AFDC). Clearly, the higher the proportion of noncash earnings to total earnings (cash and noncash), the greater will be utilities' difficulties in having both dividends to distribute and earnings to reinvest in the enterprise.

These measures are often considered indicative of the relative access which utilities may have to capital markets. If these measures, considered jointly, are in a poor state over an extended period of time, they may suggest that the utilities either do not have access to traditional sources of external funds or, if they do, that these funds could be acquired only if the utilities were willing to pay a relatively high price for their use.

Before proceeding to show the extent to which the selected measures of financial health are affected under alternative NSPS revisions, it will prove useful to highlight a few aspects of the way in which the Financial module of the Utility Simulation Model produces financial results and, thus, the context in which these results should be interpreted. (The Financial module has been described more fully above in Section 3.1.1.)

The essential characteristic of the Financial module is that it is, like other albeit less elaborately developed models of its type, an accounting structure. As such, economic and financial decisions are treated in a pre-specified manner at pre-specified times. Accordingly, these decisions are not constrained by extraordinary events such as unexpectedly high inflation or interest rates. Moreover, it should be noted that implicit in the operation of this model is a relatively high degree of "regulatory responsiveness." That is, it is assumed that at the end of each accounting year expected revenue requirements (for the following year) are readjusted. In effect, a rate hearing is held and a decision is made at the end of each year. This may be considered an optimistic assumption with respect to the possible deterioration of utilities' financial positions over multi-year periods. However, it might be inappropriate to assume that state utility commissions would be less responsive than this and still be able to maintain that the utilities can operate efficiently.

3.3.1 Return on Equity

For purposes of assessing the relative impacts of alternative NSPS revisions, it was assumed that all investor-owned electric utilities would be allowed to earn a 13 percent return on equity by their respective state commissions. As the figures in Table 3.11 under national results ("Nation", column 1) for the baseline scenarios with moderate and high electricity growth rates (M 1.2(0)0.1 and H 1.2(0)0.1, respectively) indicate, the USM projects that investor-owned electric utilities as a whole will earn less than the allowed rate of return. This result is due to a combination of factors. The principal element involves the fact that, over an eleven year simulation period, 1985-1995, in an "average year"* the costs incurred by the nation's investor-owned electric utilities are greater than the revenues they are permitted (in the year) by regulatory commissions. These costs may be greater than revenues because a net increase over the previous year's interest, O&M, and fuel costs was experienced. Since we have assumed that regulatory commissions will reassess revenue requirements but once a year, if the utilities are unable to effect a net reduction in costs in an average year, they will be unable to earn more than the allowed 13 percent return on equity. Finally, it should be noted that it is not necessarily a severe problem for utilities to earn less than that which is allowed by regulators. One of the nation's strongest investor-owned utilities, Pacific Gas and Electric Company, has been unable to earn its allowed rate of return in any one of the last five years. Despite this failure, Pacific Gas and Electric continues to be one of the most financially robust utilities in the nation.

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* The USM produces annual costs, revenues, returns on equity, etc. which vary from year to year. For purposes of interpretation, these annual values were averaged over an eleven year simulation period.

The results of the simulation under alternative NSPS revisions show the following results for the nation's investor-owned electric utilities.

SCENARIO	EFFECT ON RETURN ON EQUITY
M 1.2(80)0.03	– 3.3%
M 1.2(90)0.03	– 4.2%
H 1.2(90)0.03	– 6.5%

The investor-owned electric utilities in some regions are more adversely affected than they are in others. For example, in New England, NSPS revisions for coal-fired units have an insignificant effect on the return on equity. Effects are more readily apparent in the Mid-Atlantic, South Atlantic, East North Central, South Mountain, and Pacific regions. The greatest impacts on returns on equity due to tightened standards are projected for the East South Central, West North Central, West South Central, and North Mountain regions. Impacts are greater in these regions for both moderate and high growth rate cases.

Two important additional observations should be noted regarding Table 3.13. First, it should be noted that there is a significant difference in the effect a 90 percent removal requirement will have under the moderate and high electricity demand growth rate assumptions in certain regions. The Mid-Atlantic, East North Central, West North Central, West South Central, and South Mountain regions are more adversely affected under the high growth case than they are under the moderate growth case.

Table 3.13

RETURN ON EQUITY

for Investor-Owned Electric Utilities on a Regional Basis under Alternative Scenarios, 1985-1995

CASE \ REGION	NATION	New England	Mid-Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	North Mountain	South Mountain	Pacific
Baseline M 1.2(0)0.1	12.4%	13.9%	13.1%	10.7%	12.9%	10.9%	14.5%	10.2%	16.5%	13.2%	14.5%
M 1.2(80)0.03	12.0%	13.9	12.7	10.4	12.8	9.8	13.7	9.0	14.0	12.7	14.3
M 1.2(90)0.03	11.9%	13.9	12.6	10.3	12.8	9.7	13.7	8.9	13.9	12.7	14.3
Baseline H 1.2(0)0.1	11.5%	15.4	12.1	10.1	11.6	10.2	13.1	9.5	14.9	12.5	13.2
H 1.2(90)0.03	10.8%	15.5	11.4	9.7	10.8	9.5	11.8	7.9	13.5	11.3	12.9

Second, the results of the simulation show only a marginal effect on return on equity in going from an 80 to a 90 percent SO_2 removal requirement. The small effect that shows up in five of the ten regions is well within the margin of uncertainty.*

3.3.2 Interest Coverage

Interest Coverage ratios for investor-owned electric utilities under the various control scenarios are shown in Table 3.14. As indicated in this table, baseline conditions (current NSPS for SO_2 and particulates under moderate and high electricity growth rates) essentially foretell the extent to which utilities in particular regions may have difficulty attracting needed debt financing. In this regard, the New England, South Atlantic, East South Central, and West South Central regions could have debt financing problems under the assumptions used in the simulation model.

The interest coverage ratios in three of these regions – South Atlantic, East South Central, and West South Central – can be shown to be measurably affected by alternative NSPS revisions. Adverse effects are found in some other regions, but, with the exception of the South Mountain region, these effects may not be significant. It should also be noted that in some cases anomalies appear in these results. That is, coverage ratios going up by one one-hundredths when these might be expected to go down – but these results are well within the margin of uncertainty.

The results for the nation's investor-owned utilities are summarized as follows:

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* An extensive sensitivity analysis would be required to quantify the band of uncertainty surrounding all the key data for this analysis.

Table 3.14

INTEREST COVERAGE

for Investor-Owned Electric Utilities on a Regional Basis under Alternative Scenarios, 1985-1995

CASE \ REGION	NATION	New England	Mid-Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	North Mountain	South Mountain	Pacific
Baseline M 1.2(0)0.1	3.14%	2.52%	3.50%	2.82%	3.44%	2.78%	3.61%	2.63%	4.38%	3.42%	3.70%
M 1.2(80)0.03	3.14%	2.52	3.47	2.81	3.43	2.73	3.62	2.62	4.36	3.38	3.68
M 1.2(90)0.03	3.14%	2.54	3.47	2.76	3.42	2.73	3.62	2.62	4.36	3.31	3.68
Baseline H 1.2(0)0.1	3.01%	3.23	3.24	2.67	3.27	2.66	3.30	2.55	3.71	3.14	3.37
H 1.2(90)0.03	2.97%	3.22	3.21	2.68	3.19	2.66	3.25	2.49	3.68	3.10	3.31

SCENARIO	EFFECT ON INTEREST COVERAGE RATIO
M 1.2(80)0.03	No Change
M 1.2(90)0.03	No Change
H 1.2(90)0.03	– 1.3%

3.3.3 Quality of Earnings

It is generally assumed that astute investors will bid down share prices if AFDC is expected to represent a large proportion of earnings over a long period of time. This would be true, in part, because a high proportion of (noncash AFDC) earnings would be unavailable for immediate reinvestment in the utility. This would imply that utilities would need to go to the capital markets for additional funds if sizeable capital or any other expenditures were required. It would imply, moreover, that if a significant downturn in revenues were experienced, dividends or possible dividend increases could be endangered.

Table 3.15 shows that under the assumptions of the Utility Simulation Model, AFDC in every region of the nation assumes a much larger position in earnings statements than it has traditionally. This situation can be the result of a number of factors, most important of which are relatively high construction financing obligations tied up in the AFDC account and relatively low generation of cash earnings. That the construction financing account (AFDC) should be relatively high by historical standards can be understood by the fact that additions to generating capacity will be more costly and capital-intensive than ever before. Also, since the cost of capital assumed for the forecast period is reflective of a current weighted average cost and not an historical cost, the AFDC rate will be higher than it has ever been.

Table 3.15

QUALITY OF EARNINGS

— Percentage of Earnings That is Noncash AFDC —

for Investor-Owned Electric Utilities on a Regional Basis under Alternative Scenarios, 1985–1995

REGION / CASE	NATION	New England	Mid-Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	North Mountain	South Mountain	Pacific
Baseline M 1.2(0)0.1	38%	46%	32%	43%	36%	46%	31%	53%	22%	37%	28%
M 1.2(80)0.03	39%	46	31	44	38	50	30	57	23	36	28
M 1.2(90)0.03	40%	44	31	45	38	50	30	57	24	37	28
Baseline H 1.2(0)0.1	44%	60	38	51	43	52	37	55	30	42	34
H 1.2(90)0.03	47%	60	39	53	45	57	40	62	33	45	35

It is certainly debatable whether or not the quality of the nation's electric utilities' earnings could erode as much as that represented in the baseline scenarios. Part of this erosion is due to regulatory lag, which the Financial module includes. However, the utilities' response to earnings quality erosion would likely be to request more rate increases (to increase cash earnings) and higher returns on equity (both to increase cash earnings and to attract needed capital, which may be more difficult to do due to investors' discounting as a result of earnings quality troubles). The model does not increase the frequency of rate relief, nor does it increase the allowed rate of return on equity.*

With these considerations in mind, it should be noted that the purpose of this assessment is to show the effect, if any, on this measure of financial health, eqrnings quality, which may be attributable to alternative NSPS revisions. For the nation's investor-owned electric utilties, the results of the simulation model show the following marginal impacts on earnings quality.

SCENARIO	EFFECT ON EARNINGS QUALITY
M 1.2(80)0.03	– 2.6%
M 1.2(90)0.03	– 5.3%
H 1.2(90)0.03	– 6.8%

* Teknekron performed an analysis of the sensitivity of earnings quality to increased allowable return on equity, and found that there is a greater than one-to-one correspondence between percentage increases in target return on equity and improvements in earnings quality.

As for relative impacts on earnings quality over the ten regions considered in this assessment, the regions most affected are the West South Central and East South Central areas. Measurable effects are also shown in the North Mountain, South Mountain, and West North Central regions.

The greatest impacts on earnings quality are experienced in two of the regions with most basic financial difficulties as implied by results for the baseline scenarios. To reiterate, these regions are West South Central and East South Central. The South Atlantic region, which also has a relatively high proportion of AFDC in its baseline scenarios, is not as significantly affected. New England also has an earnings quality problem in its baseline scenarios; however, since in this region the problem may be related to nuclear capacity expansion, the alternative NSPS revisions have a negligible effect. In the results for New England, there is an anomaly which is within the margin for error.

It is important to note, at this point, the relationship between earnings quality and realized return on equity. Earnings quality is essentially a measure used to distinguish between cash and noncash earnings. Return on equity calculaitons do not make this distinction. The return on equity computation is based on a book return (i.e., not a cash-flow return), as is consistent with accepted accounting practice. Since the cash/noncash distinction is not made for return on equity, a particular region may have a poor quality of earnings ratio without its return on equity suffering to the same extent. If the return on equity were calculated on a cash-flow basis, then there would be a direct relationship between it and earnings quality.

3.3.4 Summary of Industry Impacts

Under the assumptions used in the operation of the Utility Simulation Model, the following impacts on the financial well-being of the nation's investor-owned electric utility industry may be viewed as attributable to alternative NSPS revisions:

Scenario	Return on Equity	Interest Coverage Ratio	Earnings Quality
M 1.2(80)0.03	– 3.3%	No Change	– 2.6%
M 1.2(90)0.03	– 4.2%	No Change	– 5.3%
H 1.2(90)0.03	– 6.5%	– 1.3%	– 6.8%

The regions most significantly affected from a financial perspective are the West South Central and East South Central areas. The impacts in other regions are less significant. That the impacts should be greatest in West South Central region could reasonably be expected since a large amount of coal-fired capacity subject to a revised standard is anticipated to be built in this area. A sizeable amount of new capacity – both nuclear and coal, though especially the latter – will be built in these regions prior to the units subject to a revised standard coming on line. This suggests that, particularly in these regions, though certainly in other regions as well, utilities may have difficulty attracting investors on what are now considered reasonable terms (e.g., a 13 percent allowed return on equity) to the rather bleak prospects described under the baseline scenarios.

Accordingly, there are at least two interpretations that might give such measures of financial health. First, these measures may be indicative of the extent to which state regulations in certain regions will be under pressure to facilitate electric utility financing (e.g., by raising the allowed return on equity, by increasing the frequency of rate relief, by permitting construction-work-in-progress in rate base, or by other means). Second, these measures may indicate that electric utility spending plans are too ambitious.

Irrespective of the interpretation which may be attached to figures in the baseline scenarios, the relative effects of alternative NSPS revisions, both for the moderate and high growth futures, are projected to have relatively little national financial impact.

3.3.5 External Financing Impact

Since a large proportion of the additional costs and investment expenditures required by the electric utility industry due to revisions in pollution control regulations will be financed externally, it is useful to examine the impact on long-term external financing of the alternative NSPS revisions for the nation's investor-owned electric utilities. Results of the simulation for alternative NSPS revisions on long-term financing are presented in Table 3.16.

For each of the cases considered, additional total external financing accounts for approximately 60 percent of the investor-owned utilities' NSPS revision-related investment requirements over the 1976-1995 period. The largest percentage occurs under the high growth most stringent scenario (H 1.2(90)0.03), where external financing represents 63 percent of total investment.

As shown, the utilities' long-term external financing increases significantly between the moderate and high growth baseline cases. As would be expected, the majority of this financing is made with long-term debt issues. Neither long-term debt nor preferred stock financing is forecast to be affected greatly by the alternative NSPS revisions under moderate growth. In addition, the 90 percent SO_2 removal case is not forecast to affect significantly the utilities' external financing requirements as compared to the 80 percent SO_2 removal case. The differences between the two cases are less than 0.3 percent for each type of financing. The NSPS revisions are forecast to influence common stock financing more heavily than either debt or preferred stock, although debt remains the major source of capital for the utilities. Common stock financing is forecast to increase 7 percent under both the 80 and 90 percent SO_2 removal cases. Total incremental external financing over the twenty-year period is forecast to be \$10.4 and \$11.1 billion (in 1975 dollars) for the 80 percent and 90 percent removal cases, respectively.

Table 3.16

Long-Term External Financing

	Baseline External Financing			Incremental Long-Term External Financing Attributable to Alternative NSPS Revisions		
	Long-Term Debt	Common Stock	Preferred Stock	Long-Term Debt	Common Stock	Preferred Stock
Baseline M 1.2(0)0.1	$255.2*	$ 87.0	$ 80.8	—	—	—
M 1.2(80)0.03	—	—	—	+$3.4	+$6.0	+$1.0
M 1.2(90)0.03	—	—	—	+3.8	+6.1	+1.2
Baseline H 1.2(0)0.1	363.7	158.3	111.3	—	—	—
H 1.2(90)0.03	—	—	—	+7.7	+13.6	+2.3

* All dollar figures in billions of 1975 dollars.

Under high growth, the 90 percent SO_2 removal case is forecast to require more than 2 percent more debt and preferred stock, and more than 8 percent common stock financing, which together represent, on average, less than 0.2 percent increase in total external financing per year over the 20-year period. This incremental external financing is forecast to be $23.6 billion (in 1975 dollars) through 1995.

3.3.6 Impact on National Capital Markets

The Utility Simulation Model allows for an integrated technical, environmental, and economic/financial assessment of the alternative NSPS revisions on the utility industry, as has been described above. However, the model is essentially a micro-economic impact model and is not formally "linked" to a macro-economic forecasting model. Because it is useful to examine the potential macro-economic impacts of alternative NSPS revisions for electric utility industry boilers, we have attempted to calculate these impacts by utilizing the Data Resources, Inc. (DRI) long-term macro-economic forecasting model in conjunction with our results.

This effort could be undertaken because the data that are required to perform a mcaro-economic analysis include forecasts for Gross National Product (GNP) and its components. Comparable types of forecasts are required for the operation of the Utility Simulation Model. However, producing forecast consistency is a difficult problem because of differing assumptions about the movement of key economic parameters such as the inflation rate, the growth in electricity demand and financial parameters such as bond rates, returns on equity, and external financing requirements.

Before we present the results of this co-ordinated assessment, there are several qualifications that must be made about the results. First, the DRI forecasts stop in 1990, when the financial impacts of the NSPS revisions have not yet matured. Thus, the full potential financial impact of the revisions on the nation's capital markets is not discussed. Second, the problem of forecast consistency between the two models cannot be fully resolved. Significant differences remain in parameter values, data sources, and model structure. For example, we have used the TRENDLONG 0977 forecast, which is the most consistent forecast with that of the USM based on inflation rates and other parameters. However, under the DRI forecast, an inflation rate of 5.7 percent between 1976 and 1983 drops to 4.5 percent in the late 1980's. This is contrasted to the constant 5.5 percent per year rate used in Teknekron's forecast.

Nevertheless, we believe the results presented below are illustrative and indicate the general magnitude of the macro-economic impact of imposing the NSPS revisions we have considered, although care must be taken in placing confidence in the actual forecast values.

We have selected the high growth, 90 percent SO_2 removal scenario (H 1.2(90)0.03) for analysis because it contains the largest potential macro-economic impact since the utility industry's total investment increases the most under this case (see Table 3.5). All other alternative NSPS revisions will likely result in less macro-economic impact.

Comparing the high growth baseline with the M 1.2(90)0.03 case, we forecast that in 1990 an additional \$6.2 billion dollars of plant and pollution control investment will be needed. This figure is converted to 1972 dollars, which the DRI model uses, giving \$5.25 billion. In 1990 the DRI model forecasts that GNP will be \$2,109.4 billion and gross private domestic investment, \$321.5 billion.

Thus we estimate in 1990 that the NSPS revision-induced investment for the electric utility industry will account for 0.25 percent of GNP and 1.6 percent of gross private domestic investment. From this we conclude that the NSPS revisions we considered are likely to have, at most, a small impact on the nation's capital markets, e.g., on the level of interest rates in that year.

4.0 COAL VERSUS NUCLEAR: Economics and Decision-Making As Affected by Revised New Source Performance Standards For Coal-Fired Boilers

It has been asserted by a critic of nuclear power, Charles Komanoff,* that the golden age of nuclear economics – said to have lasted from 1968 to 1975 –is over. President Carter himself has declared, in addressing a delegation at the International Fuel Cycle Evaluation Conference, that "the need for atomic power for peaceful uses has perhaps been greatly exaggerated", suggesting that all nations carefully assess the alternatives to nuclear power, "if for no other reason than economics"** (emphasis added).

Alternatives to nuclear power for new baseload electrical generation also have economic problems. At present, the principal alternative to nuclear is believed to be coal-fired plants. While the potential coal resources of the U.S. are extensive, costly restrictions on the extraction, combustion, and disposal of waste products make use of these resources an expensive proposition. It is sometimes alleged that, in the final analysis, electrification based on coal will be as expensive or more expensive than that based on nuclear power. Following this view, revisions to current New Source Performance Standards for coal-fired boilers might be sufficiently costly to tip the economic scales to a clear advantage for the nuclear alternative.

What are the economics of nuclear and coal power? Is decision-making with respect to nuclear vis-a-vis coal for new baseload electrical generating capacity likely to be significantly affected by added cost burdens placed on coal-fired plants as a result of revised NSPS? If so, in what regions of the nation can this effect be anticipated to be most pronounced? If not, what factors may operate to mitigate or otherwise make insignificant this effect? What are the principal quantifiable and non-quantifiable factors likely to be weighed in choices, on a regional basis, between nuclear and coal?

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* See Komanoff reference, Table 4.1.

** The Energy Daily, 5(204); 1, October 20, 1977.

The purpose of this chapter is to address these issues in such a way as to provide a broad assessment of the effect of a single set of possible EPA regulatory initiatives – that of revising the NSPS for coal-fired boilers. As such, the analysis does not dwell on any one of the sizeable number of sub-issues which arise in considering the relative prospects for coal and nuclear power. Rather, by presenting a brief review of a representative sample of economic evaluations of these two power technologies and by enumerating the key factors on which the relative attractiveness of each of these technologies now rests, it is hoped this assessment will prove useful in the formulation of public policy.

4.1 BUSBAR POWER COSTS

The relative economics of alternative fuel-type/plant-types is conventionally expressed in terms of busbar power costs. This means, in effect, that each fuel/plant candidate is assessed in terms of the cost which is likely to be incurred to feed its product, electricity, from the power plant to connecting transmission lines.

All anticipated capital charges, fuel, operating and maintenance expenses are taken into account in this economic evaluation. Numerous detailed calculations must be made to arrive at a busbar power cost. Crucial decisions must be made as to the assumptions which should go into the model for evaluation. Generally, every item input is based on someone's forecast, i.e., assumption, as to a "most likely" value for that item. The end-product of such an economic evaluation is a levelized cost – that is, a yearly cost spread over some period of time, which is often but not always equal to the anticipated life of the plant. This cost is expressed in terms of mills-per-kilowatt-hour. In theory, the plant which is calculated to deliver electricity to the transmission lines at least cost, e.g., over the life of the plant, would be chosen to be built. In practice, this will not always be so.

Decision-makers do not necessarily rely on "most likely" estimates for values which are critical to the evaluation. Some would rather base their decisions on "worst-case" values for these variables. If a particular fuel/plant type were to maintain its economic attractiveness under "worst-case" assumptions, then it may stand a better chance of being chosen.

Another possible reason for not choosing the alternative which is calculated to have the lowest busbar power cost has to do with the limitations which exist as to what can be quantified – as input data to busbar power cost calculations or for other purposes. In theory, probabilities can be assigned to any future occurrence. For example, one might wish to learn the probability of a nuclear moratorium or shutdown aimed at then-operating plants in a particular state. Even if the probability of such an occurrence could be determined, i.e., quantified, this information would not be reflected in anticipated unit power costs. Moreover, it is unlikely that any decision-maker would lend much credence to the precise odds produced as a result of such an exercise.

Despite these and other limitations to be discussed concerning the usefulness of busbar power cost estimates for ultimate decision-making purposes, these estimates provide a point of reference. In the following section, a review is made of three recent estimates of the unit costs for producing electricity from new baseloaded nuclear and coal-fired plants. In some respects, these estimates parallel one another; in others, they diverge. Basically, in some cases analysts would agree as to the future behavior of key variables affecting costs and, in other cases, they would disagree.

4.2 REVIEW OF ECONOMIC EVALUATIONS

Over the last three years, numerous evaluations have been conducted concerning the relative economics of coal and nuclear power. These studies have been performed by or for reactor and boiler manufacturers, electric utility trade associations, environmental organizations, and state and federal agencies. Each of these studies was conducted for a different purpose. Accordingly, the emphasis of each and the extent to which detailed calculations were performed varies enormously. Few were published with sufficient documentation to make possible meaningful comparison with other studies.

Major assumptions as to basic investment costs, escalation rates for various cost elements, and fixed charge rates differed among the studies. Further, costs were levelized over different periods of time. In sum, since these and other problems inhibited attempts to reconcile cost estimates, the generalizations which are drawn from this review should be viewed in the light in which they are intended: to establish a point of reference.

As might be expected, there are basically two schools of thought on the coal versus nuclear economics question: a coal school and a nuclear school. This difference in views is clearly manifest in Table 4.1. In the Komanoff view coal is the least-cost alternative in every region. The Electric Power Research Institute (EPRI) presents a completely contrary point of view. The National Economic Research Associates, Inc. (NERA) view is that nuclear is cheapest in most regions. (It should be noted that the results shown for NERA estimates represent but one set of figures offered by the firm in the GESMO hearings. Other sets of figures show the economic advantage of nuclear to be greater.)

4.2.1 Capacity Factors

These estimates (and others) vary for some basic reasons. Komanoff, who has made some contributions to the understanding of the recent reliability of nuclear units and of both nuclear and coal units of larger magnitude, begins with the premise that only larger (over 1000 Mw) nuclear units will be available in the future and that these units will function at significantly lower capacity factors than do smaller units built in the U.S. in the past. Consequently, he compares the relative economics of three 600 Mw coal units (he alleges units of this size are more reliable) operating at a levelized capacity factor of 70 percent to two 1150 Mw nuclear reactors operating at a 55 percent capacity factor.

Capacity factor assumptions are crucial inputs to economic evaluations such as these. That Komanoff should assume different capacity factors for coal and nuclear plants and that EPRI and NERA should assume equal capacity factors for these two types of plants makes it very difficult to compare the results of these economic evaluations.

Table 4.1

Comparison of Nuclear and Coal Busbar Power Costs on Regional Basis

(Mills/kWh)

		New England	Mid-Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	North Mountain	South Mountain	PACIFIC	
											NW	Calif.
Komanoff	NUCLEAR	55.7	55.7	52.0	54.0	52.0	54.0	52.0	54.0	54.0	54.0	55.7
	COAL	55.4	55.4	46.5	45.5	42.0	42.8	42.0	36.0	36.0	36.0	44.6
EPRI	NUCLEAR	37.7-45.5	37.7-45.5	34.0-41.2	36.4-44.0	34.0-41.2	35.4-42.8	34.7-42.0	36.2-46.4	36.2-46.4	36.2-46.4	
	COAL	43.4-52.8	43.4-52.8	39.9-48.6	42.3-51.4	39.9-48.6	38.4-46.7	37.5-44.6	40.6-51.8	40.6-51.8	40.6-51.8	
NERA	NUCLEAR	50.0	50.0	45.8	48.9	45.8	48.9	45.9	47.6	47.6	50.2	50.2
	COAL	54.7	52.7	49.3	49.6	46.5	46.4	47.5	39.7	46.2	51.0	46.3

<u>Komanoff,</u> Chas., Testimony of – on the Costs of Nuclear Power before the House Subcommittee on Environment, Energy, and Natural Resources, September 21, 1977. Komanoff compared costs of generating electricity from 3 - 600 MW coal units to 2 - 1,150 MW nuclear units. *He assumed these two configurations would achieve the same overall system reliability.* Assumed capacity factors: 55% for nuclear; 70% for coal.

<u>EPRI</u> PS-455-SR, Coal and Nuclear Generating Costs, April 1977. Assumed capacity factors: 66% for both types of plant.

<u>NERA,</u> Testimony of Dr. Lewis J. Perl, on behalf of the GESMO Utility group. Concerning Nuclear and Coal Electric Generating Capacity Expansion, 1975-2000; March 4, 1977. NERA produced estimates of busbar power costs for two scenarios under different capacity factor assumptions. The estimates shown are for the "high-cost" nuclear scenario, the figures for which parallel those made in the latest estimates for plants coming on line in 1986. Assumed capacity factors: 60% for both types of plant.

Komanoff bases his capacity factor assumptions, in part, on rough extrapolations of the recent experience of nuclear units of larger capacity. In effect, he sees no reason to believe that nuclear reactors of this size will operate very much better in the future than they do now. Utilities view this matter quite differently, as do reactor manufacturers. They believe that the performance of larger size reactors will improve with age. (It should be noted that reactor manufacturers have taken issue with some of Komanoff's findings and, obviously, with his conclusions.) They argue that a few problem plants, e.g., the Browns Ferry units #1 and #2, bias the overall performance of nuclear power. It is also argued that the units of some manufacturers perform better than others. Finally, and very importantly, it is argued that regulatory initiatives on the part of the Nuclear Regulatory Commission (NRC), and others have had a great deal to do with the less than anticipated nuclear capacity factors. It is suggested that availability factors (a measure purported to adjust for the adverse effect on capacity factors of regulatory initiatives to raise the probability that existing nuclear reactors can be operated safely) would be a more equitable measure of reactor performance. Also, it is argued that as the nuclear industry matures, as reactor designs are standardized, and as regulatory procedures are routinized, the capacity factors of nuclear power plants will rise.

It is clear that all of this takes some faith. The burden of proof rests with the nuclear industry. It is also evident that, despite all the problems of the industry, electricity now produced from nuclear reactors is competitive with that produced from coal-fired facilities. This can probably be explained in part by the fact that when nuclear units are available for use there is a large incentive to use them as much as possible — perhaps in the process relegating coal-fired units to a subordinate dispatch position.

On the matter of capacity factors, another point should be noted. In another evaluation of the relative economics of coal versus nuclear, a study group*

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* Nuclear Power: Issues and Choices; Report of the Nuclear Energy Policy Study Group, Ford/Mitre, 1977.

assumes that a coal-fired plant burning Northern or Central Appalachian coal and requiring a scrubber would have a capacity factor five to ten percent less than it would were no scrubber required.*

4.2.2 Fuel Costs

Another important factor contributing to the current economy of nuclear power is the relatively inexpensive fuel now being used in these units. Future fuel prices probably will be much higher. How much higher cannot be determined, because virtually no new uranium supply contracts now negotiated involve fixed-prices (with customary cost escalation clauses). Instead, all new contracts entered are of the "market-price" variety, wherein the selling price is determined just prior to delivery, based on then-prevailing market prices.

Since these contractual arrangements are consummated as much as a decade before deliveries begin, this presents a rather risky situation for a utility. It is especially risky since fuel costs, based on information from fixed-price contracts when they were available, are expected to represent 40 to 50 percent of total fuel cycle costs** for plants coming on line in 1986. Fuel cycle costs are now about 25 percent of total busbar power costs for nuclear units.

The combination of f.o.b. mine coal prices and transportation charges is generally assumed to account for about 40 to 50 percent of the future busbar power costs of coal units. As such, the assumptions which are made as to the future prices of coals with different characteristics, in different regions, and with different means and costs of transport are crucial inputs to busbar power cost calculations.

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* It should be noted that possible changes in the availabilities of coal units due to the installation of FGD systems have not been incorporated in the Utility Simulation Model.

** Fuel costs for a light-water reactor include the prices charged for mining and milling. Fuel cycle costs, assuming no recycle, include the prices charged for mining, milling, conversion (U_3O_8 to UF_6), enrichment (UF_6 to 3% U^{235}), fabrication (enriched UF_6 to UO_3, pelletize, sinter to UO_2, load and fabricate into fuel elements), shipping spent fuel, waste management (interim and long-term), and fuel inventory charge.

It was not possible to determine with any degree of certainty whether the busbar power cost differentials noted in Table 4.1 could be attributable to differences in assumptions as to the future prices of coal and transport. The NERA study was reasonably detailed insofar as it identified sources of coal, accordingly to Bureau of Mines' regions, and assumed cost escalation factors were stated unambiguously. A least-cost optimization model was said to have been used to determine coal flows. The EPRI and Komanoff studies lacked equivalent documentation. Other studies or models of coal flows, ones with which NERA's results might conceivably be contrasted, were not considered for this analysis.

4.2.3 Capital Costs

The economic factor most often mentioned as the major nuclear parameter is its capital cost. Building a kilowatt of nuclear capacity is estimated to cost from 15 to 30 percent more than building a kilowatt of coal-fired capacity. In the three studies compared in Table 4.1, it was estimated by Komanoff that a kilowatt of nuclear capacity would cost 26 percent more, by NERA, 24 percent more, and EPRI, 17 percent more. These are national averages; there is very little regional variation in these relationships.

In considering capital cost estimates, it is important to note not only the relationships between nuclear and coal investment figures but also the magnitude of these estimates. In this regard, Komanoff's national average for nuclear, $1,200/kw (1985 dollars, 1150 Mw), is 14 percent higher than the NERA estimate; (same size unit); his coal investment figure, $950 (600 Mw), is 11 percent higher than NERA's (800 Mw). EPRI figures could not be compared in this manner.

A higher absolute level of investment implies, other things being equal, that there will be greater amounts of interest charges that will appear in busbar power costs. This assumes, for one thing, that the same fixed charge rates are used. Komanoff and NERA did not use the same rates.

To summarize, differences in the estimated busbar power cost advantages to nuclear and coal, as displayed in Table 4.1, may be attributable to: differences in assumed capacity factors; differences in assumptions as to future delivered coal prices; and differences in capital cost and fixed charge rate assumptions.

Estimates for particular aspects of the nuclear fuel cycle could not be shown to vary. Nor could it be demonstrated that significant variation exists in projected O & M costs for either coal or nuclear.

4.2.4 NSPS Revisions and Regional Effects

Based on preliminary and rough calculations of the incremental costs associated with NSPS revisions, it can be stated that the busbar power costs of coal may increase by 6.5 mills per kilowatt-hour, $\pm$ 20 percent, in 1985 dollars. With reference to Table 4.1, this effect may be seen to tip the economic scales in favor of nuclear in three of the four areas which NERA now estimates a slight advantage for coal. Coal would maintain its advantage, in the NERA analysis, only in the North Mountain region. In the Komanoff analysis, coal would lose its advantage in the Northeast, Mid-Atlantic, and South Atlantic regions.

While these may appear significant effects in terms of a strictly quantifiable measure, their true effect on decision-making concerning coal and nuclear may in fact be quite insignificant. Estimates such as those discussed in Section 4.2 may well not be the basis for actual decision-making. In the following section, other not strictly quantifiable factors are suggested as possible reasons for choosing to build a nuclear and not a coal plant, or vice-versa.

4.3 FACTORS DIFFICULT TO QUANTIFY

In this section, factors that are difficult to quantify are viewed from two perspectives. First of all, from the perspective of a decision-maker who may be attempting to find out a number of good reasons to invest in nuclear. The list the decision-maker draws up will include, assuming there is but one other choice, coal, the principal reasons to avoid coal. The other perspective is one drawn in terms of reasons to go with coal, if for no other reason than to avoid nuclear.

4.3.1 Reasons to Invest in Nuclear And Reasons to Avoid Coal

PUBLIC SUPPORT

It is not enough to simply calculate busbar power costs, do some sensitivity runs, and then decide that nuclear power is competitive and, therefore, there can be no argument about it. What a decision-maker needs is backers, people who will help to make his choice an economic one. In this regard, because an enormous amount of taxpayers' money has already gone into the development of peaceful uses for atomic power, there is a natural desire on the part of taxpayers and public servants to see the nuclear promise realized at some time. Accordingly, it may be safe to assume that the public would not permit nuclear power be made uneconomic by, for example, lifting the tort liability protections provided under the Price-Anderson Act, by pricing enrichment services or waste disposal services at unsubsidized rates, or by eliminating certain special tax advantages.

EXPERIENCE

Firms such as Commonwealth Edison and an ever-increasing number of others are learning, by experience, about the economics of nuclear power. Significantly, Commonwealth Edison is pushing ahead with the siting and licensing of more reactors and captive uranium mine development.

DIVERSITY

Even a utility such as Commonwealth Edison which is heavily committed to nuclear, recognizes the strength in a diversity of plant/fuel types. As a result, it is also planning to build more coal-fired units. Utilities now principally coal-fired may be wishing, as the effects of the coal strike are beginning to hurt sales and profitability, that they had a reactor or two.

The threat of coal strikes is not the only reason to avoid too heavy a reliance on coal. There may be apprehension that sulfur and particulate controls will not function properly on some coal plants, and that these plants may be required to shut down until such controls are effective. The reliability and ultimately the economics of these plants could, as a result, be much worse than now foreseen.

Other factors could make coal appear uneconomic. For one thing, FGD sludge disposal costs may be higher than now anticipated. Severance taxes, greater costs for surface mine reclamation, for mine health and safety, or for miners' pension funds could make coal power lose its attractiveness.

SITING COAL PLANTS

Air quality standards make the siting of a coal-fired plant a major problem. To site a plant in or anywhere upwind of a Non-Attainment area could well involve having to invest in tradeoffs. These could prove uneconomic given the alternative of nuclear power.

In the near term, coal plants may be sited in Class II and other areas. But in so doing, the allowable degradation increments may be used up. Again, nuclear may be the only reasonable alternative in the long-term.

THE ENVIRONMENTAL EFFECTS OF EXPANDED COAL USE ARE UNKNOWN

One of the most compelling reasons to avoid coal is that new controls for nitric oxides, heavy trace metals, and toxic and carcinogenic compounds may be required. The combined cost of such emissions controls is now not available.

NUCLEAR IS YOUNG, FURTHER ASSISTANCE WOULD MAKE ITS PROSPECTS BRIGHT

Like all relatively new technologies, nuclear power has been struggling to get on its feet. It may need further help. In this regard, an elimination of the Construction-Work-in-Progress account (i.e., include construction expenditures in the rate base) would help to reduce the economic/financial bias against a capital-intensive technology. In addition, while plutonium recycle is contrary to current national policy, were this policy changed the economics of nuclear power would be enhanced marginally.

4.3.2 Reasons to Invest in Coal and Avoid Nuclear

INDIGENOUS RESOURCE

In 1976, greater than 80 percent of uranium procurements for future delivery were negotiated with firms whose mines are in four western states — New Mexico, Wyoming, Colorado, and Utah. About 14 percent of procurements is to come from foreign sources.* Nuclear electrification may end up sending a sizeable proportion of electricity rate payers' money to these four states and, increasingly, to other nations.

By contrast, coal-powered electrification can keep fuel costs circulating in local economies. Twenty-one states have substantial coal reserves. Several others have mineable through less significant reserves. NSPS revisions could make all U.S. coal available for use —that is, if these revisions imply an effective FGD mandate. Not all reserves can be developed economically, but the potential is there to have many states share in the spillover benefits of electrification.

In this regard, there may be further political/economic pressure to have reliance on indigenous coal resources become a reality. This pressure may affect utilities which have planned to build nuclear plants.

COMPETITIVE CHARACTERISTICS OF COAL MARKET

The market for coal may be seen as having more competitive characteristics than does the market for uranium. NSPS revisions may further increase the competitiveness of this market. It may also be said that the market for coal-fired boilers has more competitive characteristics than does the market for

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* Reference to study conducted by J. Patterson and G. Combs, DOE, Division of Uranium Resources and Enrichment, Supply Evaluation Branch, in The Energy Daily, 5(210); 4, October 31, 1977.

nuclear reactors. Together these factors may help to keep the busbar power cost of coal-fired units very competitive – with nuclear or other types of electrical generation.

FLEXIBILITY OF COAL-FIRED UNITS

If for some reason coal cannot be burned in the quantities now foreseen, units designed for coal can in many cases with some, albeit expensive, modification be converted to burn other fuels. Nuclear units have no such flexibility.

LESS EXPOSURE TO INFLATION

Since coal-fired units are less capital-intensive than nuclear reactors and if coal-fired units continue to maintain their several-year advantage in terms of licensing and construction, these units will be less exposed to the possibility of labor and material cost overruns due to periods of high inflation during construction. Moreover, for the same reason and with the same supposition in mind, coal-fired units will have lower interest costs during construction.

THE NUCLEAR FUEL CYCLE IS FRAUGHT WITH PROBLEMS

At present, the alternatives for acquiring uranium to fuel a reactor appear to include: (a) making a sizeable investment in a captive uranium mine – with no control over the rest of the fuel cycle (such investment in a captive coal mine might be more cost-effective); or (b) entering into a fixed-price contract with a supplier or middleman who has no bargaining strength – with the risk that the contract may be abrogated (as did Westinghouse) for reasons of "commercial impracticability;" or, (c) entering into a "market-price" contract wherein there is virtually no control over the price ultimately paid for the uranium. None of these options appear particularly appealing.

Just 12 months ago, enrichment costs were considered relatively stable at $60/Separative Work Unit (SWU).* Now, the GAO has called for higher, "fair value", prices for enrichment services. $88/SWU is set as a new interim price.

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* A separative work unit is a measure of work required to separate uranium isotopes in the enrichment process.

This increase in price will mean a yearly increase in nuclear power cost from about $4.7 million to about $6.9 million. Over a 30-year period, this is an added cost of approximately $66 million. The future is uncertain – both in terms of enrichment prices and in terms of national enrichment capacity.

Just 12 months ago, waste management was being estimated in busbar power calculations at $16/kg. Now the federal government has proposed a $100/kg price for this service, and the service is simply an interim solution. The proposed price increase would raise the yearly waste management costs to a utility from about $400,000 to $2,500,000. Over a 30-year period, this means an increase from $12 million to $75 million. There may be technological solutions to ultimate waste disposal, but there may not be an institutional/political solution for some time to come. In the meantime, other states or the federal government may follow the lead of California and Sweden in stopping nuclear power until an acceptable waste disposal solution is found.

DECOMMISSIONING

One of the frequently overlooked and potentially expensive aspects of the nuclear power alternative has to do with what it may cost to decommission a reactor. The ultimate cost will depend on numerous factors, including the size of the reactor, the period of time over which it was used, how many kilowatt-hours it produced over its lifetime, and the manner in which it is considered safest to segregate the reactor vessel and the concrete shield from society. Since a reactor may remain hazardous for one-and-a-half million years, great care will go into this decision.

Perhaps the easiest thing to do with a reactor is simply to bury, or entomb, it. But this may not be an acceptable solution in all cases. Surveillance of some kind may be required for centuries. Another possible solution is to dismantle the reactor, but radioactive dust may be dispersed in the process. To date, of the eight experimental reactors which have been decommissioned (the largest, 61 Mw), only one has been dismantled. This reactor, Elk River (22 Mw), cost $6 million to build (completed in 1962) and $6.9 million to dismantle (dismantled in 1970).*

CONSEQUENCES OF ONE MAJOR ACCIDENT

The consequences of a major nuclear accident – either here or anywhere else in the world – can be expected to be felt dramatically throughout the industry. Just as the property and human damages which might result from a major accident are, for all practical purposes incalculable, so, too, are the enconomic and financial impacts on utilities that have nuclear power plants. A major act of sabotage could have the same effect. The fact that the Emergency Core Cooling System has yet to be demonstrated to operate in a fullscale test adds to this uncertainty.

PROSPECTS FOR HAVING SUBSIDIES ELIMINATED

There is also an economic risk that one day the substantial subsidies now offered to assist nuclear power will be lost, in part or as a whole. By far the greatest subsidy is the protection offered under the Price-Anderson Act. The provisions of the Act, which were recently extended until 1986 (at which time they would need to be renewed), limit the tort liability of utilities to $125 million. The federal government promises to cover any additional damages up to $435 million. After that, nothing – though presumably emergency aid in the form of low-cost loans, etc., might be provided. Beyond $560 million, the utility is subsidized by the populace at large – including of course, any firm which would choose to locate in the neighborhood of a nuclear power plant.

There are additional taxpayer subsidies offered to nuclear power: a heavy emphasis on nuclear in federal R&D budgets; accelerated depreciation both for plant (16 years, versus 22.5 for coal) and fuel core (4 years); and fuel cycle subsidies.

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* "The Cost of Turning It Off," M. Resnikoff et al., Environment, 18 (10); 26, December 1976.

Without special treatment for nuclear power it is doubtful that, in the near-term, it could remain competitive with coal. It cannot be assumed that this special treatment will last. Coal producing states may one day clamor for making nuclear meet the market test.

4.4 SUMMARY, EMPHASIZING REGIONAL CONSIDERATIONS

This discussion of the relative economic advantage, on a regional basis, of coal and nuclear power, as effected by NSPS revisions for coal-fired boilers, had two parts. First, we discussed the key factors affecting differences in busbar power cost estimates for coal and nuclear, on a regional basis, as performed in the three existing evaluations of this type. Second, a description was made of some of the crucial difficult-to-quantify factors which may well convince decision-makers to choose one technology over another irrespective of values produced as a result of busbar power cost calculations.

It was determined from the review of three studies of regional busbar power costs for coal and nuclear that differences in results were due principally to *variation in assumed capacity factors, though also to variation in assumed coal* prices and assumed relative and absolute differences in capital costs for nuclear and coal. Based on a rough calculation of the incremental costs due to NSPS revisions, it was determined that in a few regions – notably the Mid-Atlantic and South Atlantic regions – the economic scales might tip slightly in favor of the nuclear alternative should the coal alternative be subject to a more stringent new source standard.

However, care should be taken not to read an inordinate amount into these results. This is necessary both because the incremental costs were calculated as approximations and particularly because the studies to which these costs were applied were not well documented. In sum, the purpose of the first part of the analysis was primarily to provide a quantitative frame of reference. In so doing, it became clear that nuclear and coal power are quite competitive in most regions. Finally, it should be noted that site-specific data were not analyzed. In reality, of course, true economic evaluations are made solely on the basis of such data.

In the second part of the analysis, factors which are not readily amenable to quantification were described as very important to the coal versus nuclear decision-making process. Many decisions to build one type of unit over another may be strongly influenced by such things as public support for or disfavor with subsidies to the nuclear industry, by a need to diversify a firm's generating capacity, by siting restrictions, by political/economic pressure to utilize indigenous coal resources, by a major nuclear accident, by the perceived competitiveness of coal and uranium markets, by perceptions as to ultimate costs of waste disposal, enrichment, and decommissioning and by several other factors.

As for the combined effect of all these factors, it is our judgment that the ten regions will – in general – be affected by NSPS revisions for coal-fired boilers in the ways and for the reasons described below.

New England	Relatively insensitive to revised NSPS; nuclear is perceived to have advantage; experience with nuclear; diversification possible, but other fuels competitive.
Mid-Atlantic	Relatively insensitive to revised NSPS in New York and New Jersey; more so in Pennsylvania; some diversification possible; residual fuel available due to refinery capacity.
South-Atlantic	Relatively insensitive to revised NSPS; mixed coal and nuclear.
East North Central	Relatively insensitive to revised NSPS; some utilities strongly nuclear may diversify; political pressure to use indigenous resources; siting restrictions may in some cases necessitate nuclear.
East South Central	Relatively insensitive to revised NSPS; mixed nuclear and coal; some possible siting restrictions.

West North Central	Relatively insensitive to revised NSPS; political pressure to use indigenous resources; some diversification to nuclear.
West South Central	Relatively insensitive to revised NSPS; siting restrictions possible; some diversification; residual fuels available due to refinery capacity.
North Mountain	Relatively insensitive to revised NSPS; heavy commitment to coal.
South Mountain	Relatively insensitive to revised NSPS; heavy commitment to coal; possible siting restrictions.
Pacific	In Northwest, relatively insensitive to revised NSPS; some nuclear, much hydro. In California, both coal and nuclear stymied; "coal-by-wire" from mountain states; hydro and residual fuel oil.

APPENDIX A

CAPITAL FORMATION PROSPECTS

APPENDIX A: CAPITAL FORMATION PROSPECTS

A. THE ROLE OF CAPITAL MARKETS

INTRODUCTION

No industry is more capital-intensive than the electric utility industry. To illustrate, the ratios of net investment to annual revenues in the steel, chemical, and automobile manufacturing industries are such that it takes about twelve, ten, and seven months, respectively, to generate sales revenues equal to net (depreciated) assets. By comparison, it takes about four years' worth of electricity sales revenues to match the industry's net tangible investment. The electric utility industry's current level of capital-intensiveness suggests that, under the best of circumstances, in order to fund new projects, it will require a good deal more capital funds than it it likely to raise from internal sources (depreciation allowances, retained earnings, and tax deferrals). This causes the industry to seek funds in the capital markets.

The industry's requirement for external funds from 1978 to 1995 could be very large — on the order of $200-300 billion (1977 dollars), depending on the amount of total capital need, earnings, dividend policies, and many other factors. It cannot be assumed that the industry will be able to acquire funds sufficient to do all it would like or may be asked to do. Numerous factors, many of which are discussed in this section, will affect the outcome.

The purpose of this Section is to describe the capital market environment in which the electric utility industry will find it necessary to fund a portion of one of its major spending programs — that of NSPS-related investment--through 1990. To describe this environment first a brief sketch is presented of the capital markets in which funds for all purposes are acquired. The important aspects affecting electric utilities' participation in raising external capital over the last 10 to 15 years are described next.

In the second Section, the discussion becomes prospective in nature. Factors are discussed which will affect the industry's need and ability to raise capital. Since macroeconomic factors will affect the availability and cost of external capital, some of these key economic variables are described first. The notion of "capital shortage" will be discussed briefly.

The investment and financing policies of firms seeking external capital will be important determinants of relative access to the capital markets; hence, an overview will be presented of some of the important firm-level policy decisions. First, consideration will be given to the uncertainty which pervades the industry's capital budgeting environment.

The policies of both state regulatory authorities and utility management may have a strong influence on the industry's capital-raising prospects; hence, some of the key policy options available to regulators and management will be discussed briefly.

Further, since utility investment for air pollution abatement purposes will be made in the context of the industry's possible investment requirements for other purposes, as well as the requirements of all other public and private entities and parties, a discussion will be presented of the types of projects which may compete for investment funds.

Finally, since the electric utility industry would appear to hope that a major proportion of pollution abatement spending could be funded through issuance of tax-exempt debt, particular attention is given to the feasibility of this approach to investment funding and to the impact that widespread use by investor-owned utilities of pollution control revenue bonds could have on the market for tax-exempt securities.

CAPITAL MARKETS

Capital markets are the network of institutions and mechanisms through which intermediate-term funds (loans of up to ten years maturity) and long-term funds (longer-term loans and corporate stocks) are pooled and made available to businesses, governments and individuals. Capital markets include both primary markets, in which an issuer's securities are first sold to the public, and secondary markets in which outstanding securities are transferred. Examples of capital markets include the markets for government, corporate, and municipal bonds, corporate stocks, and mortgages.

A distinction is made between capital markets and money markets. The latter are regarded as including financial assets that are short-term (obligations of a year or less to maturity) and possess low risk and a high degree of liquidity. Examples of money markets include the markets for short-term government securities, bankers' acceptances, and commercial paper.

Although focus of this section is on the capital markets, the capital and money markets should be considered interdependent. Suppliers and users of funds may use both markets depending on investment policies and on the relative rates available in the different markets. Funds flow back and forth between markets as, for example, when a bank lends the proceeds of a maturing mortgage to a business firm for a short period of time.

Some institutions serve both markets. Commercial banks, for example, make both intermediate and short-term loans. Moreover, yields in the long- and short-term markets are interrelated. A rise in short-term interest rates reflecting a condition of credit stringency is likely to be accompanied or followed by a rise in long-term rates.

To complete this introductory overview of capital markets, it is useful to distinguish the markets according to the instruments involved; that is, the instruments that represent funds supplied to and obtained from the capital markets are either debt instruments, such as corporate bonds, or equity instruments, such as corporate stocks. This distinction will prove convenient when we consider the electric utilities' participation in the capital markets.

Long-term Corporate Debt Financing

Historically, corporate bonds have been issued for a variety of reasons. The most important of these is to reduce the cost of financing and to increase the rate of return on equity capital by applying the principle of leverage. The after-tax cost of long-term debt can be lower than that of equity capital because of its preferred risk position and the tax deductibility of interest payments. Bond financing also avoids possible dilution of control.

On the other hand, debt financing has definite disadvantages. The contractual payments and restrictions on working capital and retained earnings contained in the indenture agreements inhibit corporate flexibility and diminish the appeal of debt financing. Also, because fixed changes are involved, the debt financing can have an adverse impact on earnings during an economic downturn.

Corporate debt, either secured or unsecured, can be offered either publicly or privately. Public issues are distributed through investment banking houses, which form syndicates of investment banks and underwrite the bond issues for resale to institutions and individual investors. The investment banker provides the issuers with advice on the terms, timing, and prices of bond financing and with continuing counsel after the issue is floated. Correspondingly, the members of the underwriting syndicate serve as broker-dealers and provide investors with information on the financial condition of the issuers, the form and terms of the financing, and general investment advice.

Investment banking syndicates acquire new corporate bond issues by either negotiated or competitive bidding. Direct negotiation between issuer and underwriter (acting alone or as a manager of a syndicate) ends in a purchase contract whereby the banker acquires the issue at a net price and yield determined by bargaining. Such underwriting is largely confined to offerings of industrial firms and financial institutions. Competitive bidding, in which the issuer invites sealed bids, is ordinarily required by federal or state statute in the case of public utility and railroad issues. The cost of flotation of fully underwritten public issues consists of the bannker's gross spread or commission and the expenses involved in preparation and negotiation, as required by the Securities Act of 1933. The banker's commission varies with size and quality of the issues and the methods of distribution, and ranges from 0.5 to 0.8 percent.

The price that a borrower pays for the use of borrowed funds is the interest rate. When the borrower issues a particular debt instrument, he agrees to meet a schedule of interest payments over the life of the instrument at a stated rate of interest (sometimes called the "coupon" rate). Normally, the stated rate is based upon current market interest rates for similar debt issues and is chosen so that the market value of the issue will be very close, if not identical, to the face value of the instrument. For example, if a firm is planning to sell some new thirty year bonds and similar ones are currently selling to yield 8½, then we would expect that a stated interest rate of 8½ would result in the market paying approximately $1000 for each $1000 face value bond.

Over time, market interest rates fluctuate substantially. Since the stated interest rates on outstanding debt instruments do not change, fluctuations in the market rates cause the prices at which the instruments trade in the secondary markets to adjust accordingly. If the market rate for a given bond is higher than the stated rate, the bond will sell at a discount; if it is lower, the bond will sell at a premium. The rate of return that an investor will earn if he purchases the bond at the market price and holds it to maturity is called the yield.

There is no single market interest rate. Instead, there is a range of rates, observable at any time, that encompasses such factors as the supply of funds available, the expected rate of inflation and the risk of default by the borrower. Issues of the U.S. government are normally considered free of default risk and thus their yields are used as a proxy for the market's riskless rate of interest.

This rate captures the market's time value of money, i.e., the rate at which the market is willing to forego consumption today for future consumption, and the anticipated rate of inflation, which adjusts for the loss of purchasing power of the dollars received in the future over the dollars invested now.

For issuers other than the U.S. government there is the possibility of default. Hence, the market interest rate for these issuers is equal to the riskless rate for an instrument of the same maturity (since the effect of inflation varies with maturity) plus a risk premium, which increases as the possibility of default increases. The way that the market determines the possibility of default and hence the size of a risk premium is not fully understood. However, one important ingredient of the market's decision process is the ratings assigned the bond by the two ratings agencies, Standard and Poor's and Moody's Investor Service. These agencies evaluate the quality of bonds and state their opinion in letter grade form. A brief discussion of the factors considered impoortant by these bond raters is presentedlater in this section.

While the magnitudes of the interest rate differentials between the various rating categories fluctuate over time, they are typically small relative to the fluctuations of the entire interest rate structure. And it is this latter pattern of movements which is considered to be one of the most significant aspects of interest rates – their role as an index of the availability of funds. In theory, a firm, no matter how risky, should always be able to borrows funds at some price. But in practice there are many legal and institutional constraints and conventions that place limits on how high interest rates may go. As a result, a period of high interest rates usually reflects tight money, even though the high rates may be primarily attributable to high levels of anticipated inflation. For small firms and for high risk large firms, periods of rising interest rates may indicate increasing difficulty in obtaining new debt financing.

Corporate Stock Financing

Corporate stocks in the form of transferrable certificates represent the equity interest in the company. There are two types of corporate stocks, preferred and common. Stocks having a preferred status rank ahead of common stock as the claim on assets and in the receipt of dividends. The common stock represents the residual equity in the corporation and participates in net assets in liquidation and in dividends after all claims of creditors and of any preferred stockholders have been met.

New corporate stocks are sold to investors both directly by the issuer and indirectly through investment bankers and dealers. The chief means of direct sale of common stocks is through the issuance of rights to existing stockholders entitling them to buy new shares (including covertible bonds and preferreds) in proportion to existing holdings. Sale of securities to employees in connection with savings, stock purchase, and stock options incentives is also considered direct. Some stock issues are directly placed with institutional buyers; these are chiefly higher grade preferred stocks of public utility companies.

The majority of new common stock issues of public utilities is underwritten by syndicates of investment banks, who negotiate the transaction directly with the issuer and purchase the entire offering at a price net of discounts and commissions. They then sell the new shares to the public at the offering price which usually is very close to the most recent price at which the issuers shares were traded in its secondary market (such as the New York Stock Exchange). Thus, the value which an issuer receives when selling new shares of stock is dictated by the current market price of its outstanding shares. The balance sheet or book value of the firm's shares plays no role in determining the price at which new shares are to be offered (unless it is the first public offering of the firm).

Composition of Sources of Funds

It is instructive to note that as business spending has been rising over the period 1960-1974, two significant changes in the composition of funds sources has occurred. First, internal sources of funds have declined relative to total need for funds. Second, the use of common and preferred stocks has declined relative to the use of debt instruments. These trends can be observed in Table I.

These trends signify that U.S. firms chose to grow in the Sixties and early Seventies by applying debt leverage. Of course, while the use of debt leverage has its benefits, it too has its costs. It tends to destabilize earnings since firms with fixed debt funding become more sensitive to cyclical swings in the economy. As equity investors perceive this change, they tend to require higher prospective returns to compensate them for added risk-taking. As firms become more leveraged, incremental debt generally carries higher interest rates. As the cost of financing grows, so grow the costs of production. With some lag, selling prices rise, too. Inflation may result, and this would further boost returns sought by investors.

Apparently, what has happened of late is that firms have continued to invest without earning their costs of capital. Investors again bid up the required return; consequently, share prices fell. Since some individual investors left the market entirely, seeking greater opportunities in real estate and other investments, the new equities market narrowed. Consequently, the significance of institutional trading increased.

Institutional Sources of Long-term Capital

It has been estimated that individuals hold about 70 percent of outstanding equity securities, 20 percent of corporate bonds outstanding, 30 percent of municipal debt, and about 25 percent of outstanding federal debt (these figures include holdings of individuals as beneficiaries of trusts managed by trust departments of banks). Despite their large holding of equities (mostly common stocks) indi-

Table I

Sources of Funds

Domestic Non-Financial Business Corporations
1960-1975

(billions of dollars)

	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975
Total Financing Need	$44.1	$49.2	$55.2	$57.6	$67.2	$79.2	$86.7	$86.5	$96.1	$96.3	$95.3	$116.8	$133.9	$154.1	$163.1	$137.3
Funds Internally Generated	34.4	35.6	41.8	43.9	50.5	56.6	61.2	61.5	61.7	60.7	59.4	68.0	78.7	84.6	81.5	90.3
(as percentage of Total)	78	72	76	76	75	71	71	71	64	63	62	58	59	55	53	66
Adjusted Retained Profits	10.1	10.1	12.7	13.1	17.7	21.2	23.0	20.0	16.6	10.9	5.8	10.3	15.7	17.1	9.0	11.3
(as percentage of Internal)	29	28	30	30	35	37	38	33	27	18	10	15	20	20	11	13
Capital Consumption Allowances (Depreciation)	24.2	25.4	29.2	30.8	32.8	35.2	38.2	41.5	45.1	49.8	53.6	57.7	63.0	67.5	72.5	79.0
(as percentage of Internal)	71	72	70	70	65	63	62	67	73	82	90	85	80	80	89	87
External Funds Raised	9.7	13.7	13.4	13.7	15.0	22.6	25.6	24.9	34.4	35.6	35.8	48.8	55.2	69.5	81.5	47.0
(as percentage of Total)	22	28	24	24	25	29	29	29	36	37	38	42	41	45	47	34
Bank Loans and Other Short-Term Debt	2.1	2.8	3.9	5.5	6.1	13.4	10.1	3.5	16.1	15.5	5.2	7.0	15.9	34.9	45.3	(12.8)
(as percentage of External)	22	20	29	40	41	59	39	14	47	44	15	14	29	50	56	(27)
Long-Term Funds	7.5	10.8	9.5	8.2	8.9	9.2	15.5	21.4	18.4	20.0	30.4	41.5	39.2	34.5	36.3	59.8
(as percentage of External)	78	80	71	60	59	41	61	86	53	56	85	86	71	50	44	127
Equity	1.5	2.2	0.4	(0.6)	1.3	(0.1)	1.1	2.2	(0.2)	3.4	5.7	11.4	10.9	7.4	4.1	10.0
(as percentage of Long Term)	20	20	4	(7)	15	(1)	7	10	(1)	17	19	27	28	21	11	17
Long-Term Debt	6.0	8.6	9.1	8.8	7.6	9.3	14.4	19.2	18.6	16.6	24.7	30.1	28.3	27.1	32.2	49.8
(as percentage of Long Term)	80	80	96	107	85	101	93	90	101	83	81	73	72	79	89	83
Mortgage Bonds	2.5	4.0	4.5	4.9	3.6	3.9	4.2	4.5	5.7	4.6	5.2	11.3	15.6	16.1	10.9	23.6
(As percentage of Long Term Debt)	42	47	49	56	47	42	29	23	31	28	21	38	55	59	34	47
Debentures	3.5	4.6	4.6	3.9	4.0	5.4	10.2	14.7	12.9	12.0	19.5	18.8	12.2	9.2	21.3	26.2
(as percentage of Long Term Debt)	58	53	51	44	53	58	71	77	69	72	79	62	45	41	66	53

Source: Flow of Funds Statistics, Board of Governors of the Federal Reserve System

Note: Parentheses indicate net negative flows.

viduals directly engage in trading only about 30 percent of equities, commercial banks trade about 40 percent (including trading for noninsured pension fund and for trust fund accounts), and other institutional investors — principally mutual funds, life insurance, and property and casualty insurance companies — trade the remainder.

Since institutional investors engage in about 70 percent of equity trading —versus about 30 percent in 1960 — the character of their trading habits has become of concern. It has been alleged that the institutions show active interest in no more than about 200 to 300 stocks and that they, in fact, limit trading mostly to the so-called Favorite Fifty. Not many electric utilities are among these stocks . (Institutional investors, as evidenced by their current holdings, show great interest in Texas Utilities, three Florida utilities, and PSC of Indiana; some interest in some firms located in Illinois, California, Ohio, Wisconsin, and Montana; virtually no interest in forms located in New York, Pennsylvania, and Massachusetts; and particularly low regard for the common equity of firms such as Con Ed, Boston Ed, Detroit Ed, Iowa PS, and Portland G&E).

The lack of institutional interest in most electric utilities — and indeed in about 90 percent of all stocks publicly traded — tends to make these stocks illiquid, and illiquidity tends to negatively affect share prices. Further, since the value of shares traded in the secondary market has great influence on the price of new issues, a lack of institutional activity in a particular stock can add a cost and serve as a constraint to the issuance of new utility equity.

Stocks that institutions do actively trade may also be made more risky by their trading (hence, the required return is bid up; if by no other means, by bidding the share price down). This may well be true due to the so-called "air-pocket effect" — if one firm sells a large block of shares, other institutions may follow suit. This tends to create significant swings in stock prices. Individual investors who are not privy to the same information that institutional investors are and those individuals who do not watch closely their investments may be adversely affected by institutional transactions.

In summary, there may be significant benefits to institutional activity in the stock market, but without restrictions on institutional trading, new electric utility stock issues may not enjoy a marketplace characterized by breadth, depth, and resiliency. Ultimately, this affects the financial options available to investor-owned electric utilities.

The market for debt securities is largely institutional in nature. Therefore, the policies of and restrictions placed upon financial institutions are important in determining where funds go and at what interest rates. There are essentially four markets for debt securities: the mortgage market, the federal market, the municipal market, and the corporate bond market. The interest here centers on the municipal and corporate bond markets, but it should be noted that the mortgage and federal government securities market can, at times, offer very serious competition for funds. Under normal circumstances, most institutional investors hold some proportion of their portfolios in debt securities of all types.

The Municipal Market

The major participants in the municipal market are as follows: commercial banks, with about 45 percent of outstanding securities; individual investors, including those entrusting their accounts to banks, with about 30 percent; and property and casualty insurance companies, with about 20 percent. The remaining 5 percent is shared by life insurance companies, state and local retirement funds, mutual savings banks, and business corporations. Lately the largest growth in municipal participation has been evidenced by the household (individual) sector.

The municipal bond's distinguishing feature is its tax-exempt status. The market for municipals is thus principally composed of those seeking this status for their own tax purposes; that is, investors with high marginal tax rates. The market's major attraction is also a cause for concern for those seeking funds, because when the earnings of its three large participants dip, they lose interest in the market. In fact, though they hold about 95 percent of outstanding municipals,

municipals represent only about 6 percent of the total combined financial assets of commercial banks, property and casualty insurance companies and individuals. Hence, a one percent shift in their combined assets away from municipals could have major repercussions in the municipal market. Later in this section, the municipal market will be reconsidered in light of the expanding use of pollution control revenue bonds, which now account for about 10 percent of all newly issued tax-exempts.

The Corporate Bond Market

The major participants in the corporate bond market are life insurance companies and private and government pension funds. Other participants include mutual savings banks, property and casualty insurance companies, mutual funds, commercial banks, and foreign investors.

Since most corporate bonds are purchased by institutional investors, their secondary market is rather thin. The institutions that buy these bonds are generally satisfied to hold them to maturity. However, in the event of a liquidity problem faced by a particular holder of corporate bonds, these bonds can generally be sold rather quickly – as evidenced by the narrow bid-and-ask spreads these bonds now enjoy. (Bid-and-ask spreads are stated as a percentage of a bond's face value, and refer to the difference between what a potential buyer is willing to pay and what a potential seller is willing to sell a bond for.)

ELECTRIC UTILITY PARTICIPATION IN THE CAPITAL MARKETS

Trends and events occuring over the last decade have significantly affected the setting in which the industry operates, the industry's financial condition, and the manner and extent to which the industry participates in the capital markets. Of course, the extraordinary events of 1974-1975 had a particularly adverse effect on the industry. But trends beginning earlier, that is, in the late Sixties, had the effect of making the industry very vulnerable to the Oil Embargo, high inflation, pronounced regulatory lag, and other occurrences which shook the industry and its investors in 1974-75.

Key Factors Affecting Financial Position

Demand

Over the past ten years, the industry's annual growth rate in peak demand has exceeded the annual growth rate in average system demand on six occasions, sometimes by as much as 2 or 3 percentage points. Over the last decade, in only one year, 1967, did the growth in peak demand fall significantly below the average demand growth rate. The variability in the peak growth rate was substantial over the 1966-1975 period. The peak growth rate, more than any other factor at present, signals the likely need for expansion of plant capacity. With such great year-to-year variability in the peak, the accuracy of predicting future capacity needs tends to be low. Still, the rate of peak growth, whether considered over the 1966-1973 period (8 percent) or over the 1966-1975 period (6.7 percent), seemed to indicate the need for large capital expenditures to accommodate anticipated future demand.

The financial implications of the foregoing discussion are: (1) great uncertainty had crept into the industry's capital budgeting process; (2) peak demand growth (at least for the years 1966-1973) suggested that a substantially increased amount of capital would be required to construct additional capacity — irrespective of added expenditures implied by environmental guidelines; and (3) since peak demand was rising a good deal faster than yearly average demand, operating efficiency would suffer.

Load Factor

Capacity utilization, as measured by load factor, did suffer. Over the last fifteen years, load factor has fallen from about 65 percent to its current level of 61 percent.

When peak demand rises faster than average system demand, the load factor deteriorates, and a greater portion of the industry's plant is idle or underutilized. Since three-quarters or more of the industry's costs are either actual fixed costs or essentially fixed, declining load factor signifies — other things being equal — an increase in cost per unit sales.

Increasing Costs of Production

Fixed overhead did not remain stable during this period. Indeed, it rose dramatically. Historically, the electric utility industry had been faced with the fact that the incremental cost of electrical production — that is, the cost of producing an additional kilowatt-hour — was less than the average cost of each kilowatt-hour then being produced. This meant that the more the industry built, the cheaper would be the rates everyone paid. In the late 1960s, however, the factors that made the industry increasingly cost efficient ended.

One reason for the demise of the economies associated with the building of larger conventional plants was that the industry was unable to continue lowering its heat rate, the number of BTUs from fuel required to generate each kilowatt-hour of electricity. At the same time, the major components of construction costs — equipment, materials, labor, and money — were increasing rapidly. The increase in the cost of constructing new facilities is a major factor contributing to the change in the industry's financial setting.

Cost of Capital Funds

Over the last decade, the cost of capital funds has risen steeply. This rise may be attributed chiefly to a greater use of debt financing and to the high rate of inflation and to inflationary expectations over the decade. As shown in Table 2, the yields on high-quality utility debt and equities essentially doubled over the period 1966-1976.

Costs of Environmental Controls

During the past decade, environmental protection has become an important aspect of electric utility planning and operations. Three major federal environmental laws were enacted, and had significant impact on the industry. First, the National Environmental Policy Act, enacted in 1969, affected utility plant siting and land uses. Second, the Federal Water Pollution Control Act, and subsequent amendments, affected the industry's practices with respect to the discharge of effluents and waste water in both existing and planned facilities. Third, the Clean Air Act of 1970, and the subsequent amendments to it, affected the industry's practices with respect to the discharge of air pollutants, in particular sulfur dioxide, nitrogen oxide, and total suspended particulates. In addition to federal regulations, state and local agencies proposed environmental regulations. The net effect of all these new laws and relationships was to increase both capital and operating costs.

Fuel Costs

Fuel costs began to be a problem to the industry in the late 1960s. The closing of the Suez Canal in 1967 affected oil tanker rates. Coal prices began to rise, due in part to coal industry investments in health and safety improvements and in part to the fact that the electric industry, in general, was neither vertically integrated back to the mine nor made extensive use of the long-term contract. Natural gas prices, too, began to rise as the Federal Power Commission began to lift the ceiling on these prices.

Table 2

Average Yields on Top-Grade Utility Bonds and High Quality Utility Stocks, 1966-1976

End of Month of March	BONDS Overall Avg. Yield	PREFERRED STOCK High Quality[b] Yield	Dividend Yield	COMMON STOCK High Quality[c] Earnings/Price Ratio
1976	9.36%	8.96%	9.00%	13.51%
1975	9.74	9.31	10.34	15.63
1974	8.53	8.06	8.35	11.63
1973	7.67	7.39	6.42	9.34
1972	7.81	6.99	5.96	8.55
1971	8.03	6.91	5.55	7.51
1970	8.37	7.26	5.62	7.71
1969	7.37	6.39	4.75	6.54
1968	6.39	6.04	4.85	7.01
1967	5.37	5.15	3.89	5.83
1966	5.23	4.69	3.79	5.44

Source: Moody's Investors Service

a The overall average refers to the average of 40 utility bonds, 10 in each of Moody's four top-grade ratings, Aaa, Aa, A, Baa.

b This is the highest quality preferred rated by Moody's.

c This is the highest quality common rated by Moody's.

Note: In the past few years, the ratings given the issues of electric utilities generally been lower than those given other utilities, so the percentages above may understate that cost of money to the electric utilities.

Of course, the largest fuel price increases occurred during the oil embargo, a time at which the industry was more heavily dependent on petroleum than ever before. This dependence resulted from the fact that many utilities had just completed the conversion to oil-burning of coal-fired plants in an effort to meet sulfur dioxide emission standards. In 1974, when the price of oil increased 137 percent and the price of coal increased 58 percent, the industry was dependent on petroleum for 16.9 percent of its fuel for electrical generation and on coal for 45.5 percent.

Regulatory Setting

As the industry's costs rose, it found it necessary to spend an increasingly large amount of time preparing materials for and testifying before regulatory commissions in an attempt to recover costs through rate increases. As the first wave of rate-increase applications appeared, regulatory commissions, had difficulty processing the large number of applications. More applications were forthcoming, however, and as the effects of the first round of rate increases were beginning to be felt — and, in many cases, resisted by consumers — the commissions were compelled to take ever greater pains to scrutinize the arguments for rate increases. This scrutiny required a great deal of time.

The major impact of regulatory lag on the industry's financial situation involved the fact that by the time the final order was issued to allow the applicant to boost his rates, inflation had so eaten into the sum originally requested — this this sum being calculated based on costs prevailing at the time of application — that the rate increases finally granted were insufficient to cover inflated costs. This impact was sometimes mitigated by a commission's granting of an interim rate increase while deliberations proceeded on the application itself. However, for over three-quarters of the cases decided during the period 1971-1973, no interim increases were granted.

Another way to soften the financial blow delivered by a combination of regulatory lag and inflation is to permit so-called "forward looking test years" to be used to calculate the amount of costs needed to be recovered through rate increases. This method of calculation permits applicants to predict cost trends. Perhaps fearing that applicants might erroneously inflate costs, throughout the late 1960s and early 1970s, the regulatory authorities typically did not permit such a practice.

In the early 1970s, one of the few concessions the industry was generally able to win from regulatory commissions was the authority to pass certain "uncontrollable costs on to the consumer without having to go through formal rate proceedings. By mid-1974, 43 states and the District of Columbia permitted fuel cost adjustment/pass-through clauses. On the nationwide basis, 75 percent of investor-owned utilities were permitted some form of fuel adjustment clause, though in some cases, the adjustments were restricted to industrial and commercial customers. A few regulatory commissions permitted utilities to pass through taxes and the cost of power purchased from other utilities, but as a general rule, such adjustments were not permitted.

Pass-through clauses undoubtedly helped utilities to recover costs more quickly. Still, when fuel costs were soaring, for example, during the winter of 1973-1974, even the normal lag between billing and collection added to the strain on a utility's working capital.

While the pass-through clauses gave the industry's financial condition a moderate boost, the need for rate increases to recover costs generally unrelated to fuel outlays was growing rapidly. The dollar amounts of rate increases granted annually over the period 1970-1975 grew from about $500 million in 1970 to more than $3 billion in 1975. However, far more significant to the financial condition of the industry was the fact that dollar amounts requested for rate increase approval grew from about $700 million at the end of 1970 to more than $4 billion at the end of 1975.

Since a sizable number of requests for rate relief were not acted upon immediately, it became evident that the costs the industry had incurred would have to be carried, at least for a time, by some other means. Fixed charges, such as interest payable on debt, could not be reduced, lest foreclosure proceedings be commenced. The major source of funds would have to be cash flow from operations.

Clearly what had happened was that the regulatory delays that had worked to the industry's and its investors' advantage in the ealy 1960s were now working to their great disadvantage. Whereas, in the early 1960s the industry's members were generally able to earn more than the rate of return allowed by regulatory commissions, in the early 1970s, they were generally earning less.

It is misleading to attribute all of the decline in the earnings rate of the electric utility industry to regulatory lag. Regulatory lag does not explain why the amounts requested and the amounts still pending at the end of the year were progressively so much higher year to year. Allusion has been made to some of the factors that contributed to this situation — load-factor deterioration, higher construction costs, environmental costs, and higher fuel costs. Other contributing factors, including a higher level of construction activity, greater external financing, a higher level of debt financing, and the use of certain accounting practices will be discussed in ensuing paragraphs. The combination of these factors has had extremely adverse impacts on earnings.

External Financing

As the industry found it could not prevent a lower rate of return (on shares and rate base), a number of factors came into play. The first impact of a declining rate of return in the face of a greater need for funds was that the industry was forced to become more dependent on capital markets, i.e., on external financing. A review of Table I shows this quite clearly — as earnings contributed as decreasing share to capital expenditures, external financing assumed an increasing share. As external financing of the electric utility industry increased, it came to represent an ever-growing proportion of all long term capital funds available for U.S. industry. Table 3 shows that electric utility industry financing of late has taken an extremely prominent position in the new issues market.

Table 3

Electric Utility Industry Incremental Long-Term Financing as Percent of Total For all U.S. Industries, 1965-1976

Year	Long-Term Debt	Preferred Stock	Common Stock
1965	10%	29%	7%
1966	15%	44%	8%
1967	12%	51%	9%
1968	18%	72%	8%
1969	20%	56%	10%
1970	20%	83%	19%
1971	17%	50%	22%
1972	15%	75%	24%
1973	23%	55%	33%
1974	27%	77%	51%
1975	18%	46%	51%
1976	16%	57%	46%

The declining rate of return also meant utility stocks were less attractive. While a portion of that which is returned to stockholders, the dividends, remained attractive, and in many cases become more attractive as dividend payouts were moderately increased, the other portion of the return, the capital appreciation, was falling rapidly. In the face of the overall decline in return to stockholders, investors were requiring a higher rate of return. The reasons for this fact were that general inflation made higher nominal (i.e., not inflation-adjusted) returns a necessity, and higher bond yields were pushing the required yield on common equity, the riskier the instrument, still higher. Since the industry was unable to fulfill the expectations of common shareholders, the price/earnings ratio, a measure used in the valuation of common stocks, had to fall. Table 4 shows the decline in the price/earnings ratio, the multiplier the market applies to current earnings in order to arrive at a market value, over the period 1965-1976.

The third impact of the reduced rate of return was that the industry's ability to carry heavy interest burdens was being reduced. Over the period 1965-1974, the industry's annual amounts of debt issued increased more than sixfold. Over the same period, bond yields doubled. The combination of these factors caused interest charges to grow from less than $1 billion in 1965 to $4.6 billion in 1974. Over the same period, the amount of income available to service this debt grew by only 83 percent. As a result of these trends, the annual interest coverage ratio, the ratio of net income (before payment of taxes and interest) to interest fell precipitously.

Interest coverage ratios are heavily relied upon by financial rating agencies in evaluating the quality of a utility's bonds. As these coverage ratios have declined in the last five years in particular, the ratings of the bonds of many utilities have been downgraded by the rating agencies. When a utility's bonds are downgraded, these bonds trade at a discount, i.e. the cost of new debt to the utility rises. Another, and perhaps more important, effect of declining and relatively low coverage ratios emerges from the fact that the indentures of existing issues of utility bonds have provisions which will not permit a utility to issue additional bonds when the coverage ratio falls below a certain level, generally 1.75 to 2.0 times.

Table 4

Price/Earnings Ratios of the Electric Utility Industry, 1965-1976

Year	P/E Ratio	Year	P/E Ratio	Year	P/E Ratio
1965	19.8	1969	13.7	1973	9.4
1966	16.3	1970	11.5	1974	6.3
1967	15.3	1971	11.8	1975	6.4
1968	14.8	1972	10.4	1976	7.4

With both the common stock and debt securities routes to financing fraught with problems, the industry came to rely on preferred stock far more than it had when the industry's finances were on better ground. Preferred stock was once regarded as the most expensive form of financing — in terms of cash payout — because dividends are not tax deductible to the issuing firm. However, new issues of preferred stock offer tax advantages to investing corporations (85 percent deductibility for dividends received) and this fact allows the issues to be sold at yields within a percentage point of those of common stocks.

Since preferred yields are relatively high and the amount of preferred stock issued between 1965 and 1974 rose by a factor of 10, and further, the income available for preferred dividends increased a mere 26 percent over these years, the industry's preferred dividend coverage ratio fell rapidly.

Preferred stocks are also rated by the rating agencies. Declining and low coverage ratios for these stocks lead to lower ratings, and low ratings mean higher yields will be required in the future. Moreover, as preferred stocks may also have indenture agreements which prohibit new issues when coverage ratios fall below a certain level (generally a level somewhat higher than that applicable to debt) the ability of utilities to issue more preferred stock without first raising the rate of earnings has been limited.

Internal Sources of Funds

Given the increased expense and difficulty involved in raising funds externally, it remains to be reviewed why the industry was generating a declining proportion of its investment funds internally.

The key factor in this decline involves the fact that the amount of funds a given utility can generate is relatively fixed in proportion to its existing plant. Both the rate of return allowed and the depreciation funds allowed are generally fixed in proportion to the investments in plant that the utility has made. It has been estimated that the amount of funds the ordinary utility can generate internally is approximately 4 to 5 percent of its net plant. By contrast, the industry's capital expenditures relative to initial assets rose from 7.5 percent to 13.5 percent over the period 1965-1973. Thus, even if the industry had earned all that it was allowed to earn under regulatory limitations, the proportion of its investment funds generated internally would still have declined substantially.

Another reason for the decline in importance of internally generated funds involved the use of the flow-through accounting by regulatory commissions having jurisdiction over 40 percent of the industry's assets. This method of accounting caused firms to report higher earnings, due to the use of accelerated depreciation for determining their tax payments, than they would have reported had they been allowed to use an alternative accounting method, normalization, wherein tax differences are normalized by showing a deferred tax credit. When earnings appear high, it is, of course, more difficult for utilities to convince regulators that higher rates of return are necessary. The effect of the flow-through accounting practice was to maintain, if not increase, the utilities' dependence on external financing.

Though earnings for the industry grew at an average annual rate of about 11 percent over the last decade, the quality of these earnings deteriorated badly over the period. One measure of the quality of earnings is obtained by relating reported net income to cash income. That which does not contribute to cash income is created by accounting entries and, thus, is in a very real sense "paper profit", i.e., a reporting of future cash income in the current year. In 1965, 9 percent of the industry's earnings were noncash credits. By 1974, noncash credits to income were fully one-half of net income. When so little of that which the industry reports as earnings is actual cash which can be distributed (for example, as dividends), rating agencies and investors tend to view the industry as a higher risk enterprise.

The major factor contributing to the deterioration in the quality of the industry's earnings is an accounting practice used by the great majority of commissions which regulate the industry. The practice entails prohibiting utilities from including the carrying charges of construction work in progress

(CWIP) in the base amount upon which rates are calculated. Instead of permitting utilities to pass on the carrying cost of CWIP to current rate-payers, regulators required utilities to credit an allowance for the use of funds during construction (AFDC) to income for each year in which the facility is still being built. The offsetting debit entry is to CWIP. The AFDC account includes both interest paid on construction debt and an allowance for the return on the equity portion of funds invested in the plant under construction. Only when the facility comes on-line, i.e., starts producing electricity, are rates permitted to be raised to cover the amortization of accumulated interest and equity return, as well as the actual plant costs.

It has been estimated that AFDC charges amount to 20 to 25 percent of the costs of plant. Since plant costs have risen a great deal in the last decade, these charges, which are in effect a reporting of future earnings in the current year, have become a major item in that which is reported as income. Over the period 1966-1974, the AFDC proportion of earnings rose from 5 percent to 31 percent. By 1974, AFDC had risen to such an extent that aggregate reported earnings less AFDC and dividends was negative.

Since cash earnings had become negative, the only positive sources of internal funds in 1974 were deferred income taxes, 19 percent, and amortization and depreciation, 81 percent. The former source of funds has grown far more significant of late. It may be considered, either as a noninterest bearing federal loan, one that, in effect, never has to be paid back so long as utilities' investment in depreciable assets does not decline, or as a contribution to capital by the federal taxpayers.

Another problem related to earnings reported over the last decade stems from the percentage of plant which is allowed to be depreciated annually for rate-making purposes. For tax purposes, the industry's assets are given relatively short depreciable lives — for example, four years for the nuclear fuel core, 16 years for nuclear plants, 22.5 years for nonnuclear plants — which allows for accelerated depreciation. However, for rate-making purposes, the asset lives of the industry's plant are more in line with their useful lives, 30 to 40 years.

The problem with these relatively long depreciable lives for rate-making purposes is that no more than about three percent of plant can be expensed annually to meet the cost of plant replacement. When the cost of new plant is far greater than it was for existing plant, such a low percentage added to the accumulated depreciation account each year proves inadequate to cover the cost of new plant. Again, if internal funds are insufficient, dependence on external funds is increased.

Market Participation by Public and Cooperative Utilities

Thus far, the consideration of financial condition and problems faced by the electric utility industry in recent years has focused, for the most part, on the investor-owned sector of the industry. All but 21 percent of the installed capacity and 28 percent of total customers served fall in the investor-owned sector, and these shares have remained relatively unchanged for the last decade. The fact that these shares have not changed appreciably suggests that publicly- and cooperatively-owned segments of the industry have faced many, if not most, of the problems experienced of late by the investor-owned segment.

Indeed, the publicly and cooperatively-owned utilities, too, were affected by the vagaries of demand, the deterioration of load factor, the lack of improvement in heat rate, the increasing costs of construction and environmental protection, and the increasing cost of fuel and money. The only problems they escaped were ones having to do with state regulatory commissions and distressed stock holders.

The publicly-owned and cooperatively-owned electric utilities can be subdivided into municipals, federal projects, and cooperatives according to the responsible governmental unit or agency. A discussion follows for each type of utility as to its participation in the capital market to meet its capital requirements.

Municipal Electric Utilities

The municipal utilities' percentage of electrical energy generation has remained relatively constant since 1962. In 1976 the municipals produced about 9 percent of the net electrical output, evenly divided between utilities owned by municipalities and utilities owned by state projects and power districts.

Municipal utilities participate in the capital markets by issuing bonds which enjoy interest exemption from federal income taxation. These bonds may be either revenue bonds, which are secured by the revenues of the issuing utility, or general obligation bonds, which are guaranteed by the general taxing power of the issuing governmental unit. Generally, municipal utilities find it more expedient to issue revenue bonds. The reasons for issuing revenue bonds include:

- Additional general obligation debt cannot be issued because of statutory limitations.
- Legal restrictions exist on the employment of tax revenues.
- When general credit of a municipality is not highly regarded, revenue bonds may command a more favorable market than general credit bonds and can be sold at lower interest rates.
- A governing body of a municipality may be able to issue revenue bonds by securing a simple voting majority and not, as in the case with general obligation bonds, a two-thirds majority.

In the issuance of long-term debt, the municipal utility must first obtain authorization by the governmental unit. The bonds may then be advertised, specifying the terms of the issue as to denominations, coupon rates, and maturities. The sale of the bonds takes place either on competitive bidding or a negotiated basis. Competitive bidding does deprive the issuer of the initial advice and services of an investment banker. Revenue bonds are frequently sold on a negotiated basis. The more specialized nature of the bonds make the aid of an investment banker important.

Bidding for these bonds is on a yield basis. The underwriters or syndicates bidding for an issue determine the yields for the various maturities within the issue and add a spread to cover risk and distribution expense to arrive at a cost of purchase. The successful bidder may then resell all or part of the issue with the difference between cost and resale price ranging from 1 to 1.5 percent. This gross spread depends on the type, size, quality, marketability, and maturity of the issue. The purchasers of such issues are institutions or individuals who have the most to gain by holding tax exempt bonds.

The yields on municpal bonds are determined by factors which include:

- The general level of interest rates determined by the supply of, and demand for, funds in the capital market.
- The value to investors of the tax-exempt privilege.
- The particular factors affecting supply and demand for municipal bonds.

In addition, the yields on individual issues are a function of quality, size, and marketability. Quality tends to correlate with size, with the larger issues obtaining the more favorable yields.

Municipal bond yields have doubled since 1965. Yields on long-term municipal bonds have remained about 70 percent of the yield of corporate bonds with the same maturity. It can further be stated that the spread between Aaa rated bonds and Baa rated has more than doubled. The spread was 40 basis points in 1965; in 1975 the spread has increased to 131 basis points. Unlike investor-owned utilities with Baa ratings, municipal utilities Baa-rated bonds were able to obtain long-term debt financing in 1975. A possible explanation for this is that the municipals obtain a significant proportion of their capital in a local segmented market where knowledge of the municipal may be more important than a bond rating by a national rating service.

Capital expenditures by municipal utilities have averaged about 10 percent of investor-owned utilities' spending over the last decade. Internally generated funds have contributed somewhat more to capital expenditures for these utilities than they have for investor-owned utilities. Partial explanations for this fact are that these utilities do not distribute dividends, and taxes as a percent of revenues are less than they are for investor-owned utilities (on average about 4 percent versus 15 percent). It has also been suggested these utilities do better with respect to internal funds generation since their rate requests do not have to be approved by state public service commissions. Because they have generated more funds internally, municipals have had to raise less long-term debt.

Federal Agencies

Federal agencies — for example, the Tennessee Valley Authority, which produces half the federal output and Columbia River Power System, which generated an additional 30 percent of the total — generated 12 percent of the U.S. electrical output in 1975. All of this output is marketed through federal agencies — such as the Bonneville Power Authority and the TVA itself — to nonfederal utilities who, in turn, sell it to ultimate consumers. Statutory preference in the sale of this electricity is given to public bodies and cooperatively-owned systems. Though investor-owned utilities may contract for federal power, such contracts may be cancelled on five years' notice if the power is needed by a preferred customer.

Federal power tends to cost a great deal less than that which is generated by investor-owned utilities. This fact reflects the lower interest costs required on federal debt, the fact that no taxes need be paid by federal agencies, and the fact that federal power is, as it turns out, generated at a higher load factor.

TVA, one of the more visible members of the electric utility industry, is a permanent, independent corporate agency of the Federal Government. The responsibility of this agency is to supply electric power as a wholesaler to the Tennessee Valley area. The capital investment required for the building of dams, steam plants and transmission facilities has been raised by Congressional appropriation, retained earnings, and the issuance of long-term debt. In 1960, TVA began issuing long-term debt; such financing has become the primary means for financing its capital expenditures.

Cooperatives

Cooperatively-owned utilities produced about 2 percent of the total electrical output in 1975, but they accounted for 8 percent of the total kilowatt-hour sales.

Co-ops are a creation of the Rural Electrification Program initiated in 1935 and the legislation of 1936 which established the Rural Electrification Administration (REA) to lend money to the co-ops. The original purpose for the co-op program was to see that rural areas would have electrical service that was dependable and not overly expensive. Originally, loans to co-ops were made so that distribution systems could be established. These systems would purchase wholesale power from both government-owned and investor-owned generating facilities. As some of these distribution co-ops grew in size, they realized economies in generating and transmitting electricity on their own. In 1975, co-ops had installed capacity of about 7,600 MW.

Since their creation, co-ops have been permitted to borrow funds from the federal government at attractive interest rates — 2 percent in most cases, though 5 percent in some. In 1971, the REA adopted a policy requiring certain REA electric borrowers to obtain part of their loan funds from non-government sources. This policy has caused coops to issue long-term tax-exempt debt. Cooperatives now issue several million dollars in tax-exempt debt each year.

B. FACTORS AFFECTING ELECTRIC UTILITY INDUSTRY CAPITAL-RAISING PROSPECTS

Having reviewed the nature of the capital markets and the electric utility industry's recent participation in those markets, the discussion turns to the factors which are likely to affect the ability of the industry to attract capital sufficient for purposes of complying with NSPS as well as for other possible purposes.

This section begins with a brief discussion of some of the important macroeconomic factors contained in a compilation of economic forecasts through the year 1985. This discusion is not intended to be an analytical critique of the projections or of the key assumptions which drive the projections. Instead, the purpose is simple to indicate the importance of macroeconomic variables as they may affect electric utility capital spending.

In the second portion of this section, the nature of the discussion changes somewhat. With reference to the compilation of forecasts, the discussion explores the nature of the "capital shortage" that a number of economic forecasters allege will exist in the future.

In the third portion of this section, the discussion turns to some of the macroeconomic factors which will affect electric utility capital spending. The uncertainty-filled environment in which the industry must make investment decisions is described in brief. Next, the important constraints to large-scale capital investment by the industry are discussed, and some policy options available to state regulatory commissions and utility management to overcome these constraints are discussed. Finally, some remarks are made concerning the investor-owned electric utilities' use of pollution control revenue bonds.

MACROECONOMIC FACTORS

The condition of the national economy is often considered a crucial factor in determining the need for electric utility capital spending and the ability of the industry to meet its financial requirements. In Table 5, a compilation of U.S. financial parameters prepared by FEA is reproduced. Perhaps the most important figures to consider are the estimates of real annual GNP growth for the years 1975 to 1985. These estimates range from 3.6 to 5.0 percent. The real GNP rate is important since electric utility capital requirements are to a large extent related to electricity demand (especially to peak demand, and to a lesser extent to average demand), and electricity demand is, in turn, believed to be related to real GNP growth. If real GNP growth turns out to be lower than forecast, estimates of utilities' capital requirements and external financing needs are likely to be overstated.

The corporate bond rate is another important financial parameter. Table 5 shows estimates of the Aaa bond rate. It should be noted that there are practically no utilities currently in a financial position strong enough to earn Moody's Aaa rating for their bonds. Most utilities in reasonably good financial condition are selling Aa bonds, while those utilities in fair condition are selling bonds rated A. Utilities whose bonds were rated Baa in 1974-75 were unable to secure new debt funds. Should utilities be unable to improve their financial condition in the future, they may well pay significantly more than the corporate Aaa bond rate for their external funds (provided they are not prevented by indenture agreements or usury laws from seeking the funds).

The amounts of gross private domestic investment and total savings in the national economy are also important influences on the financial markets. Table 5 shows investment and savings broken down into separate components and calculated as percentages of GNP. As gross investment (including foreign investment) must always equal gross savings (including depreciation), the investment and savings totals in Table 5 should be identical. Four of the five studies estimated total investment and total savings as about 15 percent of GNP —which is consistent with percentages achieved in the 1950s and in pre-recession 1973. For dramatic purposes, the NYSE totals do not match.

Table 5

National Finance Parameters, 1975-1985

	DRI	NYSE[a]	BDC[b]	Labor	Chase[c]
Real GNP Growth Rate[d]	4.5%	3.6%	4.3%	5.0%	3.6%
High grade (Aaa) corporate bond rate	8.6	-	7.5	-	9.9
As % of GNP					
Gross private domestic investment	15.3%	16.4%	15.6%	15.4%	14.5%
Non-residential	10.6	9.4	10.9	11.2	10.6
Inventory	0.7	3.1	0.7	0.9	0.7
Residential	4.0	4.0	4.0	3.3	3.1
Total Savings	15.3	15.0	15.6	15.4	14.5
Business	11.0	10.6	10.6	11.2	10.2
Personal	5.4	4.0	4.6	4.7	6.2
Government	-0.8	0.3	0.2	-0.4	-2.0
Federal	-1.0	-0.2	0.3	-0.7	-2.1
State & Local	0.3	0.5	-0.3	0.4	0.1
Other	-0.2	0	0.1	-0.1	0.1

[a]1974 - 1985. [b]1973 - 1980. [c]1975 - 1984.
[d]Other forecasts of GNP growth include Electrical World, 3.5%

The relative proportion of GNP constituted by total savings is an important indication of the amount of money potentially available in the capital markets. One of the major influences on the amount of savings in the economy is the rate of inflation. When the rate of inflation is as high or higher than the rate of interest, money saved actually loses value; thus, there is a greater incentive to spend than to save. Accordingly, the Chase study, which forecasted the lowest amount of total savings, 14.5 percent of GNP, also forecasted the highest rate of inflation, 6.2 percent. BDC, which estimated total savings at 15.6 percent of GNP, estimated the rate of inflation to be only 4.7 percent.

The lower the total real savings in the economy, the less money will be made available for business investment; hence, the higher the yield which must be paid to obtain that which is available. Ultimately, businesses may find interest rates are so high that a reasonable rate of return on investment cannot be generated. Therefore, one would expect that the demand for capital would be reduced; reduced demand for capital tends to result in reduced interest rates. A reduced level of inflation tends to provide incentive to save, increasing savings available for business investment or to other borrowers such as government.

Government saving is a particularly important component of total savings in that government savings are often negative; that is, it spends more than it collects in taxes. When there is a government deficit, the government must obtain money from external sources. Deficit spending may tend to drive up interest rates. A government deficit could tend, therefore, to make external financing for the utilities more costly. Chase forecasted the largest government deficit, 2 percent of GNP. DRI and the Department of Labor forecasted smaller deficits, 0.8 and 0.4 percent of GNP, respectively. BDC and NYSE estimated a government surplus of 0.2 to 0.3 percent of GNP over the next five to ten years.

Capital Shortage?

Given certain macroeconomic parameters, is there reason to expect that the U.S. will experience a "capital shortage," one that could affect the spending plans of the electric utility industry? In answering this question, it proves convenient first to segregate the relevant issues into what are, in fact, two integral parts — a macroeconomic view of capital availability and a microeconomic view of the utility industry and its member firms that are anticipated to require the capital. The macroeconomic view takes into account such factors as the aggregate amounts of prospective saving and investment, the essential manner in which prices (including interest rates) are determined, the financial conditions of the firms requiring capital, the prospective rates of economic growth and inflation, the extent to which productive capacity is now utilized, and the role of government policies (fiscal, monetary, and tax), programs, and laws, e.g., with respect to environmental protection. The macroeconomic view focuses on the ability of specific firms to generate investment funds internally and to compete for external financing.

In the last three years, a number of studies have been undertaken to assess the likely characteristics of the U.S. financial markets over the next decade. Among the studies are those summarized in Table 5. Essentially what most of the studies did was to add up a likely supply of aggregate national savings and compare that total to the capital investment plans of the nation's business corporations. Some studies found the aggregate investment figure to exceed the likely aggregate amount of savings (generally assumed to be about 4 trillion dollars over the next ten years) and thereupon declared that a "capital shortage" would exist in the U.S.

The arguments advanced to justify a concern for a "shortage" include the following:

Inflation has and will likely continue to keep internal generation of funds low relative to the need for investment funds. First, internal funds are generated chiefly through depreciation allowances and through retained earnings. In the absence of technological change and the presence of a relatively high rate of inflation, depreciation allowances may be considered inadequate to maintain a firm's stock of capital. During inflationary times, earnings are taxed at rates which do not reflect the reduced buying power of such earnings. When corporations are unable to generate funds internally, they must seek their financing needs in the capital markets. But if all corporations seek external financing at the same time, the argument is made, there may not be enough capital to go around.

Second, the argument is made that internally generated funds constitute practically all of gross corporate savings, and gross corporate saving (including depreciation) generally accounts for about three-quarters of gross saving in the U.S. each year. So, it is argued, the pool of savings may be insufficient to meet the demands placed upon it.

Another argument made to support the notion of "capital shortage" is as follows: Federal fiscal policy may foster enormous budget deficits. Deficit spending may, it is argued, cause interest rates to rise (in fact, this alleged linkage is by no means proven), and this may cuase the inflation rate to rise, and this, in turn, may inhibit internal funds generation and force corporations into the capital markets. It is also argued that mandated air and water pollution control may require capital spending of tens of billions of dollars over the next decade. Occupational health and safety legislation will also require what industry spokesmen have called "non-productive" capital spending. Further, it is argued that the nonprice rationing of credit to certain essential industries, e.g., electric utilities, would appear unlikely given the relationship between government and the banking industry in the U.S.

On the other hand, it can be stated that as a practical matter, ex post, savings always equals investment. Firms which cannot compete for capital are always "crowded out." Further, it can be said that the studies which purported to show the existence of a capital shortage took the investment plans of corporations without associating these plans to prices, interest rates, and/or the abilities of the firms to earn their costs of capital. Spending plans tend to be grandiose in the absence of financial constraints.

While a shortage of capital may not take place in the economy as a whole, it may surely take place at the level of the individual firm. Thousands of firms experience capital shortages from time to time — they cannot compete, either because they cannot lure investors or because legal restrictions prevent their would-be participation in capital markets. Are a particular state's electric utilities likely to be spurned by investors or otherwise prevented from raising capital for NSPS compliance or other purposes? It would be helpful in answering this question to be able to foretell federal and state tax policy, incentives for individuals to save rather than consume, the realistic spending plans of other firms, the expansion in the productive facilities of equipment and plant suppliers, and many other facts. These factors are very difficult to predict with any accuracy. Hence, this discussion of capital raising prospects is confined to general and suppositional areas. The discussion here turns to microeconomics and involves such factors and issues as the significance for capital formation of accounting practices peculiar to public utilities, certain utility management initiatives which might be taken to improve the industry's financial condition, and other possible policies and constraints.

MICROECONOMIC FACTORS

It was shown in the first section that the financial condition of the electric utility industry is significantly affected by a combination of factors, including low capacity utilization, a high rate of inflation, high interest costs, and regulatory lag. These and other factors affect the industry's ability to attract capital. If the industry is to be in a position to fund necessary expansion of plant, mandated NSPS, and other projects, it must, above all, generate an adequate level of earnings, improve the state of its balance sheet, and reevaluate some of its conventional management policies. It will need to do so in an environment characterized by great uncertainty, with the prospects good for more uncertainty in the future rather than less. To describe the environment in which the industry must operate, it is useful to begin with one of its most basic types of decisions: capital budgeting.

Capital Budgeting in the Electric Utility Industry

In an industry of inherently great capital intensiveness, the most crucial management decisions have to do with capital budgeting. In attempting to determine the amount and type of facilities to build to meet the demands of customers and comply with state and federal environmental protection standards, a great many factors need to be taken into consideration. For example, it is necessary to have a reasonable amount of knowledge about the amount, type, cost lead time, and profitability of capital expenditures. At present, much uncertainty clouds the investment environment. The uncertainty is manifest in areas which include:

Demand

The uncertainty of electricity demand is a major problem affecting the industry's mix, timing, cost, lead time, and profitability of capital expenditures.

This uncertainty is affected by uncertainties as to the degrees of voluntary, mandatory, and price-induced conservation likely among consuming sectors. It is affected, as well, by the interaction of a dozen or so demographic and economic variables whose future course is by no means clear. It is affected, also, both by the substitution of electricity for the direct use of certain fuels whose costs may be high or availabilities scarce and by the substitution of alternative means of power generation — for example, solar — for the electrical output.

Regulatory Response

Many believe the remedies or solutions to any financial problems the industry may have should come first and foremost from the industry's regulators — through timely and effective rate relief, allowance for higher rates of return on investment, change in accounting practices, and perhaps changes in the way electricity is priced. The regulators — federal, state, and local, evidence no common pattern of response to the industry's financial condition.

Construction and Equipment Costs

Economic choices need to be made periodically as to the amount, type, and timing of new plants — if for no other reason than to retire old, economically or technologically, inefficient plants. These choices must now be made in a setting characterized, among other things, by more lengthy plant gestation periods — which could well get longer — and potentially rapid shifts in the economic and financial advantage of one type of plant construction and equipment over another. For example, it is by no means clear, even on pure cost grounds, to say nothing of the imponderables introduced by legal interventions, whether nuclear or NSPS-complying coal-fired units will be preferred for baseload capacity.

Fuel Supply and Cost

To determine the type of capacity to build to meet an estimated demand for electricity, it is crucially important to have some notion as to the likelihood of the availabilities and costs of fuels to burn over the life of the appropriate generating plants. Since these plants may take 5 to 10 years to site, license, and build, the fuel supply and cost calculation takes as a starting point 5 to 10 years from now and continues for perhaps another thirty to forty years from the starting point.

Even in the least volatile of times such long-range forecasts are hazardous. Today, even 3 to 4 year fuel supply and cost forecasts may miss the target by a wide margin.

To begin to forecast coal supply and cost one needs, for example, some idea as to how much is in the ground and whether it can be mined at a reasonable cost. Further, it is necessary to know which coals can be mined and where. To begin to forecast the cost of nuclear fuels, one needs, for example, some notion as to the future costs of enrichment and the future availability of disposal facilities. Though fuel cost forecasts must be made for planning purposes, they should be treated with extreme caution.

One means to the control of fuel supply and cost involves the industry's purchase or lease of coal and/or uranium mines. Yet, there is a great deal of uncertainty as to whether the industry could afford such investments in supply and as to whether its regulators would permit such investments in all instances.

Environmental Constraints

The future course of environmental legislation and standards present large uncertainties to the electric utility industry. Controlling the discharge of effluents to the air and water may cost a good deal more than now anticipated. Standards may preclude the use of certain fuels and processes now in use.

Controls on the use of land for mining, generating, transmitting, or distributing energy may be more stringent than now foreseen. Environmental concern for the safety of nuclear operations could prevent large scale, if any, use of this source of electrical generation.

Federal Policies

There are numerous things that the federal government can do, wittingly or unwittingly, to help or hinder the electric utility industry. To the extent that the federal government through expenditure, tax, and monetary policy can control inflation, it helps the electric industry. To the extent that federal deficit spending is maintained or is increased, it may hinder the industry, in at least the price the industry must pay for new debt issues or for the refunding of old issues.

In the short term, the federal government could probably also help the industry — though perhaps not its rate-payers or taxpayers — by guaranteeing industry debt issues. Whether such a measure is a long-term help is more problematic.

There are other federal policies or actions which might be pursued in an attempt to aid the industry. They might include incentives to engage in load management programs, policies with respect to the accounting practices which the Federal Power Commission may permit to be used (e.g., with respect to CWIP and AFDC), and an increase in the investment tax credit rate.

REGULATORY POLICIES

State public utility commissions have considerable influence over the capital-raising prospects of the nation's investor-owned electric utilities. Potential investors view the fact that electric utilities are regulated monopolies as both an asset and a liability. It is an asset because utilities have a legal right to the opportunity of earning a fair return on their investments and because a monopoly may be less subject to the operating risks faced by competitive firms. On the other hand, the regulated nature of the industry is perceived as a liability because, in some instances, regulators have had a role to play in the instability which utilities' earnings have exhibited of late.

In May, 1976, a brokerage and research firm rated the "regulatory environment" in 46 states and the District of Columbia. (It noted Utah's Public Service Commission the most "favorable"; West Virginia's, the least.) It based its ratings on factors which include: allowed return on equity; rate request processing time, in months; test year for rate calculation, historical, forward-looking, or both; rates go into effect under bond; limit on time permitted until rate decision rendered; fuel adjustment clause; normalization of accelerated depreciation and investment tax credits; and CWIP in rate base. In effect, regulatory climate refers to alleged adverse treatment of investors either through insufficient rate of return, insufficient rate relief, or delay in granting that relief.

It is unknown the degree to which investors attach importance to these subjective ratings or to the factors upon which the ratings are based. If investors believe the factors very significant, they may either bid up the returns required in particular states or from particular utilities. One thing that can be observed, however, is that there are electric utilities in states which have so-called unfavorable environments which are doing quite well, and there are utilities operating in so-called favorable regulatory settings which are not doing very well. Perhaps the only real evidence that "regulatory environment" is being taken into account explicitly can be found in the area of bond ratings. This fact and its implications is discussed in the next portion of this section.

There are three particularly interesting regulatory policies which, if altered, have a major effect on utility finances and thus capital-raising prospects. They are: CWIP/AFDC treatment, the automatic fuel adjustment clause, and the cost of capital adjustment clause. Until recently, there were four such policies to consider, but last year, Congress would appear to have removed one from immediate need for consideration. This one involved the question as to whether utilities should be permitted to normalize tax credits and accelerated depreciaiton or whether Public Service Commissions could force them to flow-through the benefits of these tax subsidies to current rate-payers. In effect, normalization was decreed. (California's PUC has vowed to take the issue to the Supreme Court.) A discussion follows of the three remaining policies for consideration.

Construction Work in Progress (CWIP)

CWIP is a temporary utility plant account which collects all funds, including the cost of construction funds, which are tied up in the construction of new facilities that have not yet come on line. When the facilities are completed, their costs are transferred to a permanent plant account — a rate base account.

Currently, 35 states, the District of Columbia, and the FPC exclude the CWIP account from the rate base. The major arguments in support of this policy are: (1) the costs of future generating plants should be borne by future rather than current ratepayers, or, to state it differently, utilities should be able to charge consumers only for assets that are "used and useful"; and (2) utility management should have an incentive to see that projects are completed and completed expeditiously. The major arguments for CWIP inclusion in rate base are: (1) cash flow would be increased at a time when it is most needed; and (2) both the quantity and cost of capital would be reduced; hence, the ultimate cost of the electricity would be reduced.

Inclusion of the CWIP account in the rate base, given that the allowed rate of return were kept constant, would, of course, immediately increase electricity rates and revenues. Ceteris paribus, taxes would also increase, since net income would be higher. Construction projects would be much less risky, however, since including CWIP in the rate base reduces the risk of building a plant which, if not deemed necessary by a regulatory commission, might not be included in the rate base upon completion. With the risk reduced, external financing could be cheaper. Inthe long term, this could result in lower electricity rates.

The "Construction Work in Progress" account includes the interest and equity costs of construction funds. These costs are capitalized in the account "Allowance for Funds Used During Construction" (AFDC) which is credited to income over the construction period. AFDC is noncash, non-taxable income and, like CWIP, is currently not allowed by many regulatory commissions to be collected in rates until the plant is transferred to the rate base. Were CWIP to be included in the rate base, there would no longer be a need for AFDC since the utility would be realizing revenues that cover the interest costs on CWIP.

The following example shows the relationship between capital expenditures, the AFDC account (an income statement account), and the CWIP account (a balance sheet account). In the example, the following assumptions are made: (a) capital expenditures are made the first day of the year; (b) the AFDC rate is 8 percent; (c) the plant takes three years to build; and (d) after three years of construction expenditures, including those for use of construction funds, the plant comes on line.

Year	Capital Expenditure	AFDC	CWIP at end of year
1	$100	$ 8	$108
2	200	24	332
3	100	32	464

The important points to note from the example are (1) the CWIP account accumulates all capital expenditures and AFDC associated with the construction of the plant. When the plant comes on line, the amount of CWIP associated with the plant is added to the rate base and begins to be amortized for rate-making purposes. (2) For tax purposes, only that portion of the CWIP account which represents capital expenditures, $400 (i.e., excluding AFDC) may be depreciated; (3) for tax purposes, only the debt component of AFDC is an allowable expense and this deduction must be taken in the period in which the interest was paid. (4) AFDC is not compounded.

Fuel Adjustment Clauses (FACs)

During the Embargo and shortly thereafter, electric utilities argued strenuously for the right to use automatic fuel adjustment clauses to pass on to customers the rising cost of fuel without having to go through formal rate proceedings to do so. The argument was that fuel costs were not in any way controllable by utilities and it made no sense to require utilities to formally justify expenses over which they had no control. Further, fuel costs were seriously depleting cash positions. All but five states agreed with utilities and allowed FACs to be used. It may have appeared that the FAC issue was resolved, and that in the future, utilities could count on charging customers on a timely basis increases infuel costs.

But the issue is far from resolved, as evidenced by a recent speech given by President Carter in which he stated that: "It is hard to believe that every time energy costs go up, that utility companies automatically raise your rates, and the regulatory agencies don't have a thing in the world to say about it. That ought to be changed."

The President no doubt had in mind a July 1977 report by the Senate Governmental Affairs Committee, which criticized Public Service Commissions for permitting utilities to pass through in FACs both direct fuel and non-fuel expenses. Non-fuel expenses in FACs include those involving line losses, efficiency factors, taxes and fees. fuel handling costs, fuel-related salaries and labor, allowance for uncollectable expenses, lag correction factors, wheeling charges, hydro and geothermal power. The authors of the report suggest that FACs have been abused and that FACs should be abolished.

The issue is not clear cut either way. There may be good arguments for relieving utilities and Public Service Commissions from the drudgery of having to scrutinize, in lengthy proceedings, many costs which utilities cannot control. This assumes these costs are indeed uncontrollable. If they are uncontrollable, regulators might more profitably focus on controllable costs and devise a performance/incentive structure for dealing with these costs agreed to be under management control. That is, allowed rate of return might be tied to management performance — as it is supposed to be in the rest of the corporate sector.

As for the immediate financial consequences of a possible abolition of FACs, if the electric utility industry is an increasing cost industry, the normal regulatory lag associated with the review of expenses which were previously passed on in FACs will adversely affect the industry and its capital-raising prospects.

<u>Capital Adjustment Clause (CAC)</u>

In April 1975, the New Mexico Public Service Commission instituted a novel rate-making mechanism which, if adopted by other PSCs, could have very important implications for the ability of the electric utility industry to attract funds from the capital markets. For the Public Service Company of New Mexico, the PSC established an automatic capital adjustment clause which permits the utility to adjust rates on a quarterly basis such that it realizes the rate of return on equity allowed by the Commission. The Commission set a range of 13.5 percent to 14.5 percent for the return on equity.

In effect, the CAC guarantees that at the end of each 3-month period — i.e., not prospectively — the equity return will be no less than 13.5 percent. By the same token, every quarter the equity return is adjusted down to a ceiling level of 14.5 percent, if during the preceeding three months, it has exceeded that level.

Clearly, this is a different sort of equity. This raises some interesting public policy questions. Some of these questions will be explored momentarily. But first, it is useful to consider the PSC's motivation for establishing the CAC and what CAC's effect has been to date.

New Mexico PSC's basic motivation for instituting the CAC was that it saw a need for the utility to attract capital at the least possible cost in order to build new generating capacity. Specifically, it saw a need to build coal and nuclear plants. It recognized that construction costs had mushroomed in recent years, and it believed that while fuel adjustment clauses recover some costs on a timely basis, the normal regulatory lag involved in scrutinizing other costs had a sufficiently adverse effect on earnings' stability that funds to be used for construction were becoming more difficult and expensive to attract.

It has been determined that the CAC has had a positive influence on Public Service Company's cost of capital. Limited evidence suggests a decrease in its cost of debt, and more robust evidence suggests an increase in its P/E ratio roughly equivalent to a one to two percent decrease in its cost of equity.

From a public policy viewpoint, the principal problem with the CAC is that it may tend to reduce a good deal of the risk which equity investors can be expected to be willing to assume for a 13.5 to 14.5 percent return. If this be the case, then the risk is shifted to consumers.

Another question is whether issuing this form of equity is less expensive than issuing debt in the same amount. This is a difficult question since there may be serious constraints on the firm's ability to do so — even with the earnings stabilizing influence of a CAC. Further, it can be argued that at some point a firm needs an infusion of equity capital to maintain its target debt/equity ratio. Undoubtably these questions and others involving the New Mexico PSC's CAC will be debated at many other PSC's in the near future. Streamlining the regulatory process by essentially eliminating the need for adversary proceedings may be a course of action implying greater efficiency, but the risk/reward element tends to be altered by such initiative. Probably the ultimate question with the CAC is the same as it is with the normalization/flow-through, CWIP/AFDC, and FAC issues; that is: Is there a high probability that consumers will receive a net benefit from a change in policy?

MANAGEMENT POLICIES

The policies noted thus far would require regulatory initiative for change. There are other policies which may affect capital-raising prospects which utility management would need to take it upon themselves to establish. These policies and their possible effects on financial position are described below.

Debt Ratio

Financial decisions concerning capital structure and dividend policy may have a significant impact on an electric utility. It has been suggested that utilities increase their debt ratio; that is, their degree of financial leverage. A change of this nature in the capital structure could have a noticeable financial impact, particularly because most U.S. electric utilities are already highly levered (the average debt-equity ratio is approximately 1:1). A higher debt ratio could lead to a lower revenue requirement, since the after-tax cost of debt is less than it is for equity. However, equity holders would require a higher rate of return to compensate them for their additional risk, and there may be no net reduction in the weighted average cost of capital. But, if the proportion of debt in the capital structure were to increase, since interest charges are tax deductible, taxes would decrease if rates did not change. If rates were to rise, however, net income might benefit greatly, due to the increased degree of financial leverage. This same leverage would hurt the utility considerably in the case of a decline in revenues. External financing might become increasingly difficult with a higher debt ratio, and this might curtail some capital spending.

Dividend Payout

Another change which financial management could implement would be to decrease dividend payout. This, in turn, would increase the proportion of earnings which the utility could retain and reinvest in its projects. One theory holds that investors are indifferent to the amount of dividends they receive, assuming the retained earnings are reinvested profitably. Therefore, decreasing dividend payout should result in less need for external financing and perhaps in greater incentive for the utility to undertake capital expenditures. Rates would be unchanged, as would taxes, since dividends are not a tax-deductible expense. However, another theory holds that investors do value more highly stocks which pay higher dividends — current income. Adherents to this latter theory would argue that if the dividend payout were reduced, the utility would lose equity holders, thereby having to raise rates somewhat to increase the return on equity to attract new equity holders.

New Types of Capital Expenditures

As has been noted, a great deal of uncertainty now pervades the environment in which the industry must plan its capital expenditures. For example, it does not know precisely what types of new generating facilities to build — baseload, intermediate, or peaking — what would be most economical and most reliable for baseload — coal or nuclear — and whether or not an attempt should be made to acquire leases or producing companies to secure fuel supplies of a certain type for new generating plants.

The industry must also consider the possibility that, for example, State Implementation Plans for emissions to air may be tightened to require either that fuels with different characteristics be used, that coal cleaning plants be financed and constructed to reduce the polluting characteristics of the fuel, or that stack gas desulfurization investments be made.

There is an enormous number of possible investments for which the electric utility industry may feel a need or may be required to make between now and 1995. The following is a partial list of possible capital investments which might be made prior to 1995.

- New generating plants of an appropriate mix.
- Physical or chemical coal-cleaning facilities associated with the use of existing plants.
- Scrubbers for all new plants and for some proportion of existing plants. Investment in sludge disposal facilities.

- Facilities constructed for compliance with the water pollution control act.

- Purchase or lease of coal and uranium mines. Acquisition of operating companies. Investment in mining equipment, additional railroad spurs, conveyor belts, slurry pipelines, etc.

- Investment in railroad rolling stock.

- Investment in gasification and liquefaction projects.

- Investment in solar energy — either for electricity-making purposes or for installation in consumer homes.

- Investment in making consumer loans for insulation retrofit.

- Investment in transmission and distribution facilities, including those that are more energy-efficient or environmentally-benign but which carry higher first-costs (presumably lower life-cycle costs, or some form of subsidy would be requested).

- Undergrounding of existing distribution facilities.

- Investment in load management hardware — at the utility end and very likely at the consumer end as well.

- For combination utilities, investment in gas supply projects, as well as insulation retrofit and conventional transmission and distribution investment.

It is not clear what all these possible investments would cost. It is clear that some investments should make others unncecessary. However, it is also evident that not all these investments can be made prior to 1995. Still, there are advocates for each type of investment, and there will be competition among advocates to effect the course of electric utility capital spending.

The existence of this competition for the spending capacity of the industry suggests three things. First, it suggests capital expenditures for purposes related to NSPS revisions could squeeze out possible expenditures for other purposes. Second, it suggests that state regulatory commissioners will be under pressure to expand the industry's spending capacity by permitting higher allowed returns and other favorable treatment. Third, it suggests that, if state regulators permit increased spending capacity and if the rates of GNP and savings do not increase as fast as the rate at which industry spending capacity does, the industry may command a greater share of available capital than it would otherwise.

Constraints to Greater Investment

It has been suggested that the level of earnings the industry can generate proves to be the greatest determinant of the success which will be had in attracting investment capital. Earnings affects share prices which, in turn, affect the ability to raise equity funds. Earnings also affects interest coverage ratios which, in turn, affect bond ratings. Bond ratings have proven in recent years crucial constraints on the ability to issue debt securities. In 1974-1975, no utility with bonds rated Baa or below was able to issue debt.

Bond ratings are purported to measure the probability that a firm will meet its debt obligations in a timely fashion. A lower rating implies a lower probability of prompt payment; hence, a higher degree of risk. Riskier bonds must carry greater risk premiums to compensate investors for bearing the risk of default.

In the last decade, bond ratings have become extremely significant in affecting the capital-raising prospects of firms whose financial positions are not as robust as those of the nation's strongest and most stable firms. Electric utilities, which a decade ago were considered both strong and stable, are now frequently counted among the firms whose ability to gain relatively good ratings for their bonds is somewhat problematic. Indeed, in recent years, numerous utility bonds have been downgraded. The industry appears to consider 1976 a fairly good year in this respect, since only eight bonds were downgraded that year, whereas 15 received such treatment in 1975.

What privileges accrue to the firm with relatively high ratings for its bonds? First, it can attempt to market the bonds in the widest possible market for securities. Institutional investors — including commercial banks, insurance companies, and pension funds — are generally prohibited from purchasing any bonds below Baa. Second, the firm is more likely to get the proceeds it needs with lower transaction costs. These costs include investment bankers' fees and commissions, and such costs tend to rise the more difficult it is to place the bond with an eligible and willing buyer. Third, the firm is likely to acquire the debt funds at a lower effective interest rate.

The magnitude of the effective interest rate presents special problems to firms operating in about a dozen states. The problem is a statutory one, the states' usury laws. These laws prohibit lenders of certain types — read: investors — from requiring more than a certain percentage effective annual interest on any loan. The statutory percentage rates vary from state to state, but the majority are in the range of 9 to 12 percent per annum.

An exhaustive legal analysis of the extent to which usury laws would present a serious constraint to utility capital formation has not been performed to date. However, it is clear that in certain states investors are not exempt from these usury provisions. As matters now stand, under the current usury laws of some states, a utility with a relatively low bond rating must either sell bonds of a shorter term and lower interest rate or sell bonds (the maturity of which may match the life of the asset) with an interest rate which exceeds the usury level and trust that there will be lenders willing to risk the possibility of legal complications.

One of the interesting aspects of bond rating practices is that the raters now look beyond such matters as a firm's asset protection, financial and management resources, and earnings stability, to subjective measures of the regulatory/political climate of the state in which the utility operates. Firms operating in "favorable" regulatory climates — that determination being made based on allowed returns, present accounting practices, and other factors noted earlier — may be given the benefit of the doubt where there is some question as to appropriate rating. Clearly, the firm that has limited financial and management resources, exhibits wide swings in profitability (due perhaps, in part, to a highly leveraged position), and which operates in an unfavorable regulatory environment may have serious problems attracting outside capital.

POLLUTION CONTROL REVENUE BONDS

It is estimated that the United States business sector invested about $7.5 billion in 1977 for pollution control purposes. The investor-owned electric utility industry accounted for about $2.3 billion, or 30 percent, of the estimated total. Sixty-five percent of the investor-owned utilities share went to air pollution abatement, thirty percent to water pollution control, and five percent to waste disposal. Eleven percent of all new utility capital expenditures was devoted to pollution control.

About half of all new capital raised by the business sector for pollution control spending is being acquired by use of tax-exempt pollution control revenue bonds (PCRB's). These tax-exempt issues now represent about ten percent of all new debt issued by state and local governments. It is thouught that over the next ten to fifteen years PCRB's issued by public authorities for the benefit of private firms could assume a much larger share of the tax-exempt market. In so doing, the expanded use of PCRB's may present a number of problems the ulimate effect of which could be either a loss of advantage for their use by private firms or an abolition of that use.

The use of public credit to finance private projects began forty years ago with the industrial revenue bond (IRB's) program; however, IRB's were not widely used until the economic boom in the Sixties at which time states and municipalities bid against one another to attract industry. In 1968, an enormous amount of IRB debt was issued, so much that municipal bond rates rose by twenty-five basis points. Urged by municipal organizations and the Treasury Department, which argued that a massive amount of income tax revenue would be lost, Congress redefined eligibility requirements for use of IRB's, and their use fell to about $40 million in 1969.

Congress, believing private investment in pollution control facilitates a use of IRB's that was genuinely in the public interest, continued to legitimize the use of pollution control revenue bonds. Subsequent passage of the water and air pollution control acts essentially mandating certain private expenditures implied an expanded use of PCB's. In effect, it was determined that the cost of cleaning up the environment should be a responsibility shared between industry and taxpayers.

It is a concern for the nature and possible magnitude of the shared-burden which prompts a growing interest in tax-exempt pollution control financing. One concern is that federal and, in many cases, state and municipal tax revenues may be adversely affected by the expanded use of PCRB's. One estimate is that PCRB's will cost the federal government more than $1 billion a year in foregone tax revenue by 1980. Another $450 million will be incurred by state and local governments — the loss representing higher interest costs caused by overloading the tax-exempt bond market with private industry debt and representing lost tax revenue as well. It is argued that the major proportion of the tax loss to government is due to the tax sheltering PCRB's would provide those investors in the highest tax brackets, those for whom the tax-exempt feature has the greatest attraction.

Precisely how much more state and local governments would have to pay in interest costs due to the alleged flooding of the tax-exempt market by PCRB's is very difficult to estimate. This would depend among other things upon the phase of the economic cycle, the cash positions of the principal market participants, the relative size of the municipal issue, and the magnitude of tax-exempt debt used by the business sector and particularly by the electric utility industry.

Energy policies, environmental protection standards (form and stringency), and Internal Revenue Service rulings will have a great deal to do with the magnitude of PCRB's which the electric utility industry may wish to use. An energy policy which encourages utilities and other industries to use dirtier, though perhaps more plentiful, fuels implies greater use of PCRB's. Further, an energy policy which encourages load flattening implies greater need for and use of coal and nuclear baseload units. Both types of plants may be considered "dirty".

The immediate problems with coal are fairly evident, though further research may find all sorts of new environmental problems related to its use. Further tightening of standards for known pollutants may be required, and standards for other emissions the effects of which are not now well understood, may be necessary.

The use of nuclear power plants involves serious pollution problems as well — due to radiation. The very design of nuclear power plants may be seen as an attempt to minimize hazards from radiation. It has been estimated that from twenty-two to thirty percent of the investment in nuclear power plants could be considered for purposes of pollution control (radiation and other pollution). If the IRS confirms this estimate, a very large proportion of the investment could be financed with tax-exempt securities. Since it is estimated that investment could be made in as many as 187 nuclear plants by the year 1990, this could mean as much as $6.5 billion worth of nuclear power PCRB's coming to the tax-exempt market each year from now until 1990. This would represent about twenty percent of the entire new issues market, for nuclear power alone!

Clearly, the above scenario bodes ill for state and local governments seeking funds. It should be noted that seventeen states have interest rate ceilings on their tax-exempt general obligation bonds, and these limits are nearly met already. It should also be noted that it has been suggested that states and local governments issue taxable bonds to widen their access to the capital markets. It would seem ironic if states and local governments in the future gained a large proportion of their external funds in the taxable market while private firms dominated the tax-exempt market.

Political reality suggests this cannot happen. Indeed it suggests that if state and local governments make sufficient noise about the potential effects of expanded use of PCRB's, the PCRB as a financial tool for private industry may be endangered.

On balance, it could well be that private industry will share the disenchantment that some state and local governments have expressed for the thin, volatile tax-exempt market. Yield spreads between good-quality corporate bonds and PCRB's have narrowed considerably in recent years. In future years, PCRB yields could conceivably rise above some corporate rates. All this suggests that the once clear financing advantage of PCRB's may only continue to exist under certain circumstances. Congress may perceive "the problem", for last year it enacted another method of sharing the pollution control investment burden with tax-payers — by permitting such investments to qualify for both accelerated depreciation and tax credits.

APPENDIX B
GENERATING UNIT COSTS OF SO_2 AND PARTICULATE CONTROLS

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GENERATING UNIT COSTS OF SO_2 AND PARTICULATE CONTROLS

The generating unit cost of SO_2 control to meet the revised new source performance standards as a function of the coal sulfur content for a typical new 500 MW plant is illustrated in Table B-1. Cost for the current and the revised SO_2 standards is illustrated in Figure B-1. These costs are for a limestone wet slurry flue gas desulfurization system having a 90 percent removal efficiency. If less than 90 percent removal of SO_2 is required to meet the standard, it is assumed that only part of the flue gas will be scrubbed.

The costs are based on a plant capacity factor of 0.65 and a capital recovery factor of 0.15. The energy required to operate the FGD system is included as the cost of the replacement capacity (and its associated pollution control devices) needed to provide the energy. Interest during construction is not included for this simplified cost comparison, although it is in the Utility Simulation Model. Also, differences in fuel and boiler costs for the various fuel types are not considered here. This comparison illustrates that <u>based on SO_2 control costs alone</u> the revised new source perfomance standards provide low sulfur coal with less of a cost advantage than the current new source performance standard.

Table B-2 illustrates the cost of particulate control as a function of the coal sulfur content for a typical new 500 MW plant meeting an emission limit of 22 ng/J. The costs of meeting the current particulate limit of 43 ng/J and a 22 ng/J limit are illustrated in Figure B-2. The proposed 13 ng/J limit is not illustrated here. Hot-side ESP costs are shown for a fuel that is a subbituminous coal or lignite with a sulfur content less than one percent. For all other fuels, cold-side ESP costs are illustrated. In the Teknekron Utility Simulation Model, the levelized least-cost particulate control device (ESP or fabric filter) is selected. In the model, in all cases, fabric filters were selected for use on the low sulfur Western coals.

Table B-1

Typical Limestone Slurry FGD Costs (1975) for a New 500 Mw Plant Burning Various Coals to Meet a 90% Removal SO_2 Standard

Coal Type	Heating Value (J/g)	Sulfur Content (ng/J)	Capital Cost ($\$10^6$)	Fixed Operating Cost ($\$10^6$)	Variable Operating Cost @ CF = 1.0 ($\$10^6$)	Capacity Penalty @ CF = 1.0 (MW)
Bituminous	30,700	455	43.25	0.41	7.11	26.9
Bituminous	25,600	1,410	55.71	0.41	12.89	27.0
Subbituminous	19,800	350	42.94	0.41	6.44	28.6
Lignite	16,300	490	46.08	0.41	7.13	30.7

Table B-2

Typical Electrostatic Precipitation Costs (1975) for a New 500 Mw Plant Burning Various Coals to Meet a Particulate Standard of 22 ng/J

Coal Type	Heating Value (J/g)	Sulfur Content (ng/J)	Ash Content (ng/J)	Capital Cost ($\$10^6$)	Fixed Operating Cost ($\$10^6$)	Variable Operating Cost @ CF = 1.0 ($\$10^6$)	Capacity Penalty @ CF = 1.0 (MW)
Bituminous	30,700	460	1,680	16.49	1.23	0.05	3.2
Bituminous	25,600	1,410	4,030	11.67	0.89	0.117	2.4
Subbituminous	19,800	350	4,650	30.74	2.42	0.136	6.0
Lignite	16,300	490	4,180	31.91	2.51	0.122	6.3

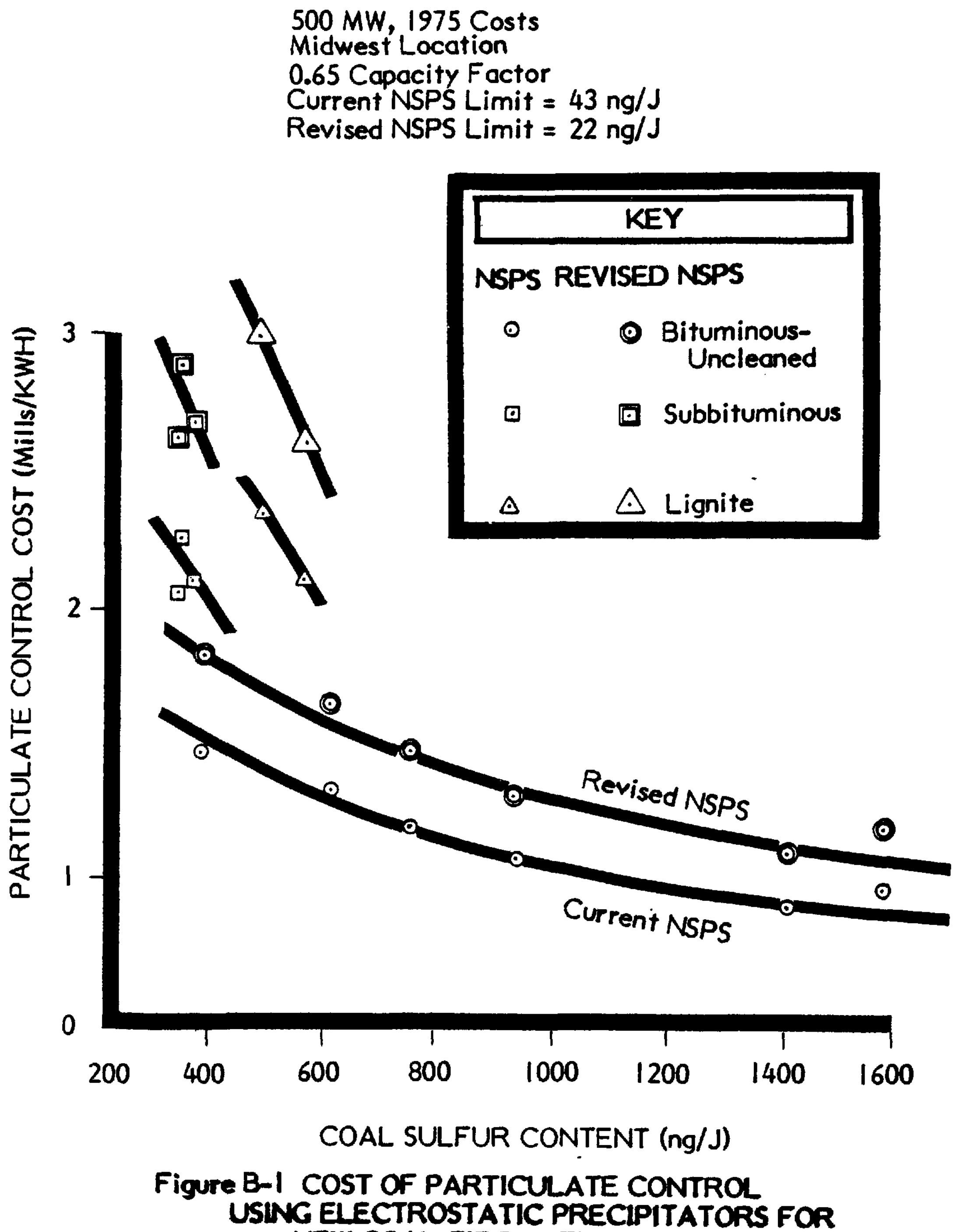

Figure B-1 COST OF PARTICULATE CONTROL USING ELECTROSTATIC PRECIPITATORS FOR NEW COAL-FIRED UTILITY BOILERS

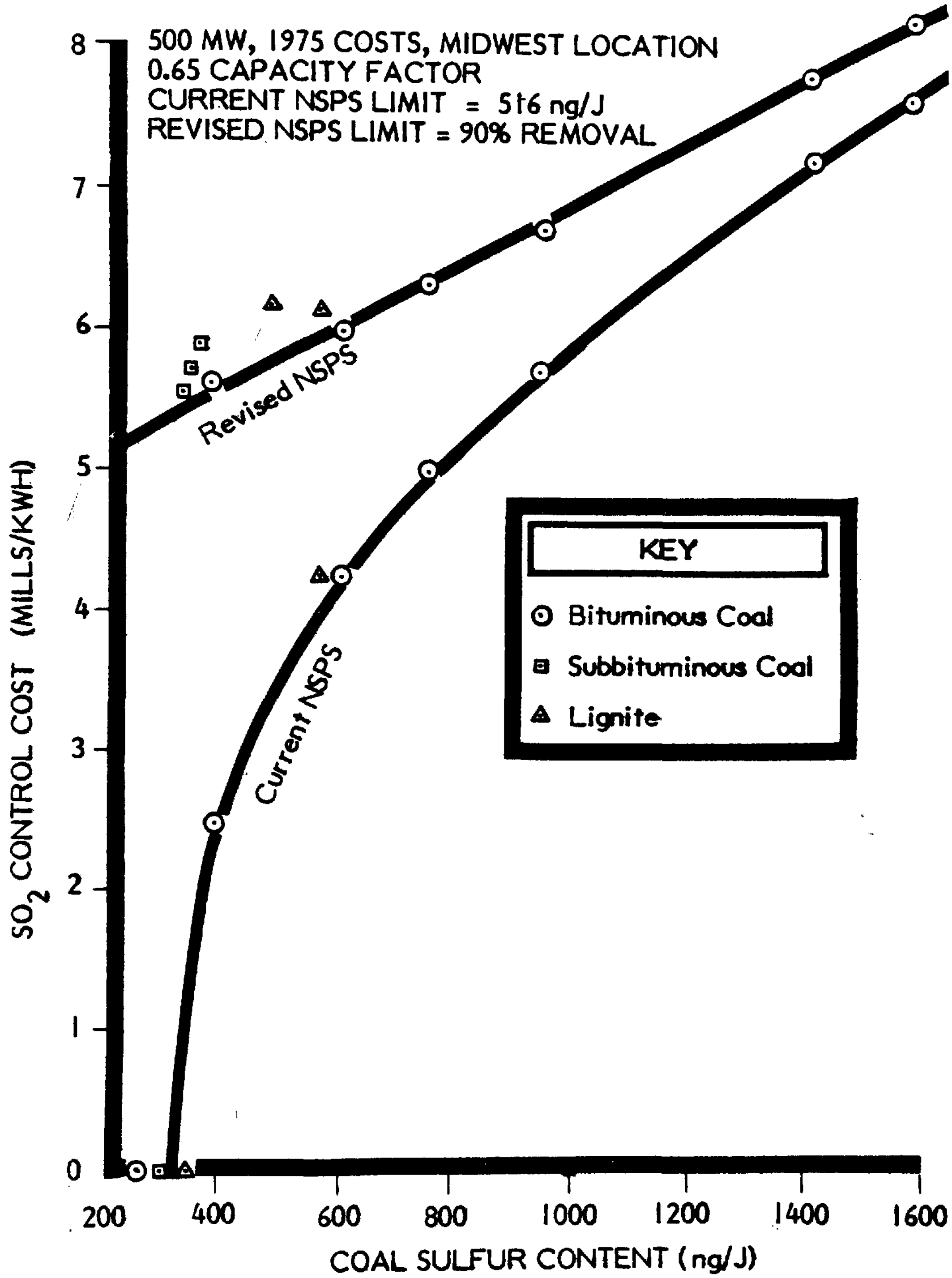

Figure B-2 COST OF SO_2 CONTROL FOR NEW COAL-FIRED UTILITY BOILERS USING A LIMESTONE FGD SYSTEM

The basis for the particulate control costs are the same as for the FGD costs, and operating energy costs are calculated as discussed previously. The cost comparison illustrates that the type of coal used is as important as the emission limit in determining particulate control cost.

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16. ABSTRACT
This two volume report summarizes a study of the projected effects of several different revisions to the current New Source Performance Standard (NSPS) for sulfur dioxide (SO_2) emissions from coal-fired utility power boilers. The revision is assumed to apply to all coal-fired units of 25 megawatts or greater generating capacity beginning operation after 1982. The revised standards which are considered are: (1) mandatory 90 percent SO_2 removal with an upper limit on emissions of 1.2 lb SO_2 per million Btu; (2) mandatory 80 percent SO_2 removal with the same upper limit; (3) no mandatory percentage removal with an upper limit of 0.5 lb SO_2 per million Btu. In addition, effects of revising the NSPS for particulate emissions from the current value of 0.1 lb per million Btu down to 0.03 lb are quantified. Projections of the structure of the electric utility industry both with and without the NSPS revisions are given out to the year 2000. Volume 1 discusses air emissions, solid wastes, water consumption, and energy requirements. Volume 11 discusses economic and financial effects, including projections of pollution control costs and changes in electricity prices.

17. (Circle One or More) KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Earth Atmosphere Combustion Energy Conversion	Energy Cycle: Energy Conversion Fuel: Coal	97G

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