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FINANCIAL AND REGULATORY FACTORS AFFECTING THE STATE AND REGIONAL ECONOMIC IMPACT OF SULFUR OXIDE EMISSIONS CONTROL

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I. Financial Overview

Before considering the effects of particular air pollution control policies on electric utilities we will survey the general financial condition of 106 oil and coal burning utilities in the 31 state ARMS region (see Table 1)[1/]. Their current status can best be understood by assessing a variety of factors: standard financial market indicators (bond ratings, return earned on common equity, and the ratio of market price to book value of common stock), sales and planning data, and state regulatory policies.

Financial Condition of Individual Utilities

It is particularly important for utilities to maintain satisfactory values of the traditional financial measures because the bulk of their extremely expensive construction projects is financed in the capital markets (rather than by retained earnings). Our financial discussion centers on the two primary means of raising outside funds: selling bonds and selling new shares of common stock.

<u>Bond Ratings</u>. Bond ratings are intended to measure the relative likelihood of a company's defaulting on a particular debt obligation; though they take numerous considerations into account, a primary determinant is the interest coverage ratio (yearly earnings divided by interest payments). Ratings affect not only a company's ability to market its bonds but also the interest rate it must pay, since if it has a relatively low rating investors will want a higher interest rate to compensate for the increased risk.

Moody's has nine categories in its rating system, from Aaa to C. Aaa and Aa bonds are considered high grade; A and Baa, medium grade; Ba and below,

Table 1. Class A and B Utilities in the ARMS Region Which are Included in the Study (*)

Alabama

Alabama Power Company*
Southern Electric Generating Company[2]

Arkansas

Arkansas Missouri Power Company*
Arkansas Power & Light Company*

Connecticut

Connecticut Light & Power Company, The*
Connecticut Yankee Atomic Power Company[1]
Hartford Electric Light Company, The*
Northeast Nuclear Energy Company[1]
United Illuminating Company, The*

Delaware

Delmarva Power & Light & Subsidiary Company*

Florida

Florida Power Corporation*
Florida Power & Light Company*
Florida Public Utilities Company[3]
Gulf Power Company*
Tampa Electric Company*

Georgia

Georgia Power Company*
Savannah Electric & Power Company*

Illinois

Central Illinois Light Company*
Central Illinois Public Service Company*
Commonwealth Edison Company*
Electric Energy, Incorporated*
Illinois Power Company*
Mount Carmel Public Utility Company[3]
Sherrard Power System[3]
South Beloit Water Gas & Electric Company[3]

Indiana

Alcoa Generating Corporation[3]
Commonwealth Edison Company of Indiana*
Indiana Kentucky Electric Corporation*
Indiana & Michigan Electric Company*
Indianapolis Power & Light Company*
Northern Indiana Public Service Company*
Public Service Company of Indiana, Incorporated*
Southern Indiana Gas & Electric Company*

Table 1. (Continued)

Iowa
- Interstate Power Company*
- Iowa Electric Light & Power Company*
- Iowa Illinois Gas & Electric Company*
- Iowa Power & Light Company*
- Iowa Public Service Company*
- Iowa Southern Utilities Company*

Kentucky
- Kentucky Power Company*
- Kentucky Utilities Company*
- Louisville Gas & Electric Company*
- Union Light Heat & Power Company[2]

Louisiana
- Central Louisiana Electric Company, Incorporated[1]
- Gulf States Utilities Company*
- Louisiana Power & Light Company*
- New Orleans Public Service, Incorporated*

Maine
- Bangor Hydro Electric Company*
- Central Maine Power Company*
- Maine Electric Power Company, Incorporated[3]
- Maine Public Service Company*
- Maine Yankee Atomic Power Company[1]

Maryland
- Baltimore Gas & Electric Company*
- Conowingo Power Company[2]
- Potomac Edison Company, The*
- Susquehanna Electric Company[2]
- Susquehanna Power Company, The[2]

Massachusetts
- Boston Edison Company*
- Cambridge Electric Light Company*
- Canal Electric Company*
- Eastern Edison Company[2]
- Fitchburg Gas & Electric Light Company*
- Holyoke Power & Electric Company[3]
- Holyoke Water Power Company*
- Massachusetts Electric Company[2]
- Montaup Electric Company*
- Nantucket Electric Company[3]
- New Bedford Gas & Edison Light Company*
- New England Power Company*
- Western Massachusetts Electric Company*
- Yankee Atomic Electric Company[1]

Table 1. (Continued)

Michigan
- Alpena Power Company[3]
- Consumers Power Company*
- Detroit Edison Company, The*
- Edison Sault Electric Company[3]
- Michigan Power Company[2]
- Upper Peninsula Generating Company*[4]
- Upper Peninsula Power Company*[4]
- Cliffs Electric Service Company[2]

Minnesota
- Minnesota Power & Light Company*
- Northern States Power Company*

Mississippi
- Mississippi Power Company*
- Mississippi Power & Light Company*

Missouri
- Empire District Electric Company*
- Kansas City Power & Light Company*
- Missouri Edison Company[2]
- Missouri Power & Light Company[4]
- Missouri Public Service Company*
- Missouri Utilities Company[4]
- Saint Joseph Light & Power Company*
- Union Electric Company*

New Hampshire
- Concord Electric Company[2]
- Connecticut Valley Electric Company[2]
- Exeter & Hampton Electric Company[2]
- Granite State Electric Company[2]
- Public Service Company of New Hampshire*

New Jersey
- Atlantic City Electric Company*
- Jersey Central Power & Light Company*
- Public Service Electric and Gas Company*
- Rockland Electric Company[2]

New York
- Central Hudson Gas and Electric Corporation*
- Consolidated Edison Company of New York, Incorporated*
- Long Island Lighting Company*
- Long Sault, Incorporated[3]
- New York State Electric & Gas Corporation*
- Niagara Mohawk Power Corporation*
- Orange & Rockland Utilities, Incorporated*
- Rochester Gas & Electric Corporation*

Table 1. (Continued)

North Carolina
- Carolina Power & Light Company*
- Duke Power Company*
- Nantahala Power & Light Company[3]
- Yadkin, Incorporated[1]

Ohio
- Cincinnati Gas & Electric Company, The*
- Cleveland Electric Illumination Company, The *
- Columbus & Southern Ohio Electric Company*
- Dayton Power & Light Company, The*
- Ohio Edison Company*
- Ohio Power Company*
- Ohio Valley Electric Corporation*
- Toledo Edison Company, The

Pennsylvania
- Citizens' Electric Company[3]
- Dusquesne Light Company*
- Metropolitan Edison Company*
- Pennsylvania Electric Company*
- Pennsylvania Power Company*
- Pennsylvania Power & Light Company*
- Philadelphia Electric Company*
- Safe Harbor Water Power Corporation[1]
- UGI Corporation*
- West Penn Power Company*

Rhode Island
- Blackstone Valley Electric Company[2]
- Narragansett Electric Company, The *
- Newport Electric Company*

South Carolina
- Lockhart Power Company[1]
- South Carolina Electric & Gas Company*

Tennessee
- Kingsport Power Company[2]
- Tapoco, Incorporated[1]

Vermont
- Central Vermont Public Service Corporation*
- Green Mountain Power Corporation*
- Vermont Electric Power Company, Incorporated[2]
- Vermont Yankee Nuclear Power, Incorporated[1]

Virginia
- Old Dominion Power Company[2]
- Virginia Electric & Power Company*

Table 1. (Continued)

West Virginia
- Appalachian Power Company*
- Monongahela Power Company*
- Wheeling Electric Company[2]

Wisconsin
- Consolidated Water Power Company[3]
- Lake Superior District Power Company*
- Madison Gas & Electric Company*
- Northern States Power Company*
- Northwestern Wisconsin Electric Company[3]
- Superior Water Light & Power Company[3]
- Wisconsin Electric Power Company*
- Wisconsin Power & Light Company*
- Wisconsin Public Service Corporation*
- Wisconsin River Power Company[3]

* Utilities included in the study .

[1] Utilities excluded from the study because they have zero oil plus coal generating capacity.

[2] Utilities excluded from the study because they have zero generating capacity.

[3] Utilities excluded from the study because they are extremely small.

[4] Upper Peninsula Power Company is a distributing company for Upper Peninsula Generating Company but it has significant generating capacity relative to the generating company and so they are treated together. Missouri Power & Light and Missouri Utilities are distribution companies for Union Electric and have only insignificant amounts of generating capacity relative to it, and so they are excluded from the study.

speculative. (Other rating agencies have quite similar categories and while the ratings of utilities' debt issues may differ between agencies, they rarely differ by more than one category[2/].) Moody's ratings for the latest debt issue of each of the utilities in this study are in Table 2. A summary shows:

Aa	21
A	34
Baa	32
Ba	5
B	3
not rated	11
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Thus, about one-fifth of the utilities are in a "high grade" category and one half have ratings of A or better. Compared with data from the recent past, however, utilities' ratings have declined. Another agency, Standard and Poor, has tallied its upgradings and downgradings over the past decade and shows that downgradings of utility debt have greatly exceeded upgradings in the years since 1977. (Similar imbalances occurred in 1971 and 1972 and immediately following the "energy crisis" of 1974[3/].) Standard and Poor also notes that pretax interest coverage ratios for utilities peaked in 1976-77 and began to erode in 1978 (averaging 2.6 in 1980)[4/]. So, while a substantial number of utilities in the region have reasonably good debt ratings, overall, their position in this market has declined from its previous level. A partial explanation is that utilities have traditionally used debt in higher proportions than other industries, and the extremely high interest rates prevailing in the market in the past few years have eroded the coverage ratios of companies that are continuing to finance ongoing construction projects.

There seems to be some regional pattern in bond ratings. Several states--Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Minnesota, Mississippi, New Jersey, New York, Ohio and Wisconsin--have a high proportion of utilities (half or more) with ratings of Aa or A. On the other hand, the utilities with

Table 2. Financial Survey of Major Coal and Oil Burning Utilities in the ARMS Region

state/ utility	billion kWh generated in 1980	1980 ROCE (std)[1]	1980 mkt/ book[2]	1980 bond rtg[3]	1980 ROCE (alt)[4]	% change, kwh sales 1973-1980[5]	1980 % proj new capac[6]	1980 % oil capac[7]	1980 % coal capac[8]
Alabama									
Ala Pwr Co	33.5	.116	.725	Baa	.156	23.8	.029	.017	.62
Arkansas									
Ark-Mo Pwr	1.6	.107	.69	N/R	.136	4.4	0	1.000	0
Ark Pwr,Lt	20.0	.077	.69	Baa	.041	37.1	.438	.369	0
Connecticut									
Ct Lt,Pwr	10.9	.097	.63	Baa	.119	6.7	0	.927	0
Hartfd El Lt	5.8	.111	.63	Baa	.112	2.8	0	.995	0
United Illum	4.7	.122	.66	Baa	.058	-3.4	1.529	1.000	0
Delaware									
Delmarva	7.5	.101	.77	A	.093	35.2	.176	.564	.366
Florida									
Fla Pwr Corp	18.8	.088	.73	Baa	.220	26.9	1.145	.849	.120
Fla Pwr,Lt	44.7	.111	.67	Baa	.178	27.1	.268	.807	0
Gulf Pwr	5.9	.072	.725	A	.108	19.1	.554	.021	.930
Tampa El	10.6	.165	.80	Aa	.218	14.2	.482	.481	.660
Georgia									
Ga Pwr Co	46.3	.155	.725	Baa	.218	11.5	.333	.115	.760
Sav El,Pwr	2.3	.070	.40	Ba	.144	12.4	.272	.804[10]	0
Illinois									
Cent Ill Lt	5.0	.102	.69	Aa	.190	26.2	.287	0	.980
Cent Ill Pub Serv	8.8	.108	.85	Aa	.144	20.7	.271	.098	.902
Com Ed	62.2	.105	.53	A	.085	2.8	.731	.290	.450
El Energy Inc	5.9	.130	.75	N/R	.114	-22.0	0	0	1.000
Ill Pwr	14.5	.134	.89	Aa	.141	28.2	.436	.150	.849
Indiana									
Com Ed of Ind	2.5	.119	.53	A	.124	-49.6	0	0	1.000
Ind-Ky El	9.2	0	.80	Baa	0	-1.9	0	0	1.000
Ind,Mich El	24.1	.103	.83	Ba	.144	30.5	.405	.062	.420
Indpls Pwr,Lt	8.8	.151	.80	Aa	.189	14.0	.904	.124	.876
N.Ind Pub Serv	12.9	.081	.72	A	.126	11.1	.461	.072	.890
Pub Serv Inc	19.0	.128	.85	Aa	.172	29.2	.504	.036	.950
S.Ind G&El	4.4	.152	.72	Aa	.192	46.3	.839	.169	.810
Iowa									
Interstate Pwr	3.7	.096	.74	A	.122	29.6	.501	.216	.784
Iowa El Lt,Pwr	4.0	.114	.70	A	.134	23.3	0	.174	.420
Iowa-Ill G&El	4.0	.121	.82	A	.163	19.0	.998	.209	.370

Table 2. (Continued)

state/ utility	billion kWh generated in 1980	1980 ROCE (std)[1]	1980 mkt/ book[2]	1980 bond rtg[3]	1980 ROCE (alt)[4]	% change, kwh sales 1973-1980[5]	1980 % proj new capac[6]	1980 % oil capac[7]	1980 % coal capac[8]
Iowa									
Iowa Pwr,Lt	4.4	.132	.57	A	.171	20.4	.075	.225	.750
Iowa Pub Serv	3.5	.119	.83	Aa	.139	2.5	.135	.267	.710
Iowa S.Utils	1.6	.129	.69	Aa	.115	21.7	.783	.013	.980
Kentucky									
Ky Pwr	6.4	.117	.83	A	.148	100.7	.351	0	1.000
Ky Utils	10.8	.067	.74	Aa	.121	40.4	1.103	.049	.940
Louisville G&El	7.8	.121	.74	Aa	.197	3.2	1.538	0	.920
Louisiana									
Gulf States Utils	29.6	.129	.70	Baa	.123	38.6	.484	.165	0
La Pwr,Lt	23.4	.146	.69	Baa	.125	27.0	.549	.196	0
N.Orleans Pub Serv	5.7	.052	.69	A	.081	16.9	0	.012	0
Maine									
Bangor Hydro	1.3	.074	N/A	N/R	.156	22.7	0	.560	0
Cent Me Pwr	6.0	.092	.76	Baa	.135	6.5	.650	.707	0
Me Pub Serv	.5	.103	.58	N/R	.116	20.0	0	.935	0
Maryland									
Balt G&El	17.2	.119	.69	A	.143	11.9	.657	.477	.180
Potomac Ed	9.8	.125	.68	Baa	.152	40.4	6.082	.092	.841
Massachusetts									
Boston Ed	11.9	.104	.70	Baa	.167	-2.5	.424	.753	.040
Cambridge El Lt	.9	.091	.69	Aa	.196	-2.3	0	1.000	0
Canal El	4.8	.119	.69	Aa	.119	23.4	0	1.000	0
Fitchb. G&El Lt	.4	.104	1.17	Baa	.111	1.6	1.758	1.000	0
Holyoke Water Pwr	.5	-.004	.63	N/R	-.012	-66.5	0	.826	0
Montaup El	4.3	.112	.70	Baa	-.030	10.5	.204	1.000	0
N.Bedfd G&El Lt	2.4	.123	N/A	N/A	.295	14.5	.796	1.000	0
N.Engl. Pwr	16.6	.130	.76	A	.206	5.5	0	.702	0
W. Mass El	3.4	.088	.63	Baa	.118	-7.8	0	.269	0
Michigan									
Consumers Pwr	25.5	.096	.68	Ba	.074	-3.2	.165	.191	.380
Detroit Ed	34.2	.086	.67	Baa	.084	-9.5	.517	.304	.670
Up.Pen. Pwr,Gen[9]	3.7	.025	1.12	N/R	.071	158.9	2.398	.503	.370
Minnesota									
Minn Pwr,Lt	8.6	.113	.77	A	.198	65.9	.390	.086	.830
N.States Pwr	22.2	.118	.77	Aa	.140	26.5	.140	.137	.570

Table 2. (Continued)

state/ utility	billion kWh generated in 1980	1980 ROCE (std)[1]	1980 mkt/ book[2]	1980 bond rtg[3]	1980 ROCE (alt)[4]	% change, kwh sales 1973-1980[5]	1980 % proj new capac[6]	1980 % oil capac[7]	1980 % coal capac[8]
Mississippi									
Miss Pwr Co	6.7	.104	.725	A	.147	17.3	.271	.086	.710
Miss Pwr,Lt	12.9	.181	.69	A	.178	67.4	1.408	.275	0
Missouri									
Empire Dist El	2.5	.105	.77	A	.172	9.7	.340	.236	.720
Kansas City Pwr,Lt	8.6	.140	.66	A	.185	13.0	.226	.149	.640
Mo Pub Serv	2.5	.099	.47	N/R	.155	7.8	1.195	.315	.570
St Jo Lt,Pwr	1.1	.122	.52	A	.197	15.7	.189	0	.560
Union El	24.9	.127	.72	Baa	.146	14.6	.365	.128	.860
New Hampshire									
Pub Serv NH	6.2	.134	.72	Baa	.087	65.1	1.887	.588	.370
New Jersey									
Atl City El	5.6	.119	.78	A	.153	27.2	.356	.447	.320
Jersey Cen Pwr,Lt	12.9	.035	.28	B	.061	24.5	.705	.483	.100
Pub Serv El&G	30.2	.119	.69	A	.131	4.3	.280	.599	.170
New York									
Cent Hud G&El	4.8	.123	.66	Baa	.103	24.3	.354	.949	0
Con Ed	30.7	.104	.50	A	.133	-20.0	.135	.757	0
LILCO	13.6	.134	.82	Baa	.036	-.2	.425	1.000	0
NYSE&G	10.8	.122	.70	Baa	.121	6.4	.838	.008	.980
Niag Mohawk	31.8	.108	.70	A	.094	-7.0	.544	.589	.260
Orange & Rockld	3.7	.095	.71	A	.152	1.1	1.402	.879	0
Roch G&El	6.8	.091	.63	A	.079	-5.4	.391	.271	.260
North Carolina									
Carolina Pwr,Lt	30.3	.110	.77	Aq	.102	18.4	.717	.174	.560
Duke Pwr	52.3	.136	.72	Baa	.091	11.9	.974	.047	.610
Ohio									
Cinn G&El	14.6	.117	.67	Aa	.102	16.7	.541	.183	.817
Cleve El Illum	18.2	.113	.81	A	.101	-3.8	.232	.130	.640
Col & S.Ohio El	9.9	.121	.83	A	.153	20.7	.649	.057	.920
Dayton Pwr,Lt	10.2	.100	.73	A	.065	10.7	.577	.138	.862
Ohio Ed	19.1	.100	.82	Baa	.062	0.0	.252	.078	.860
Ohio Pwr	40.5	.137	.83	Ba	.158	12.9	.205	0	1.000
Ohio Valley El	16.0	.138	.77	N/R	.079	-8.5	0	0	1.000
Toledo Ed	7.4	.106	.75	Baa	.080	4.9	.345	.062	.730

Table 2. (Continued)

state/ utility	billion kWh generated in 1980	1980 ROCE (std)[1]	1980 mkt/ book[2]	1980 bond rtg[3]	1980 ROCE (alt)[4]	% change, kwh sales 1973-1980[5]	1980 % proj new capac[6]	1980 % oil capac[7]	1980 % coal capac[8]
Pennsylvania									
Dusquesne Lt	13.3	.081	.59	Baa	.09	-.1	.124	.072	.740
Metropol Ed	7.8	-.027	.28	B	-.052	-7.9	1.106	.111	.430
Pa El	11.1	.058	.28	B	.072	7.8	.046	.039	.800
Pa Pwr	3.3	.096	.82	Baa	.089	-.3	.114	.004	.995
Pa Pwr,Lt	22.4	.102	.71	Aa	.056	8.9	.548	.324	.650
Phil El	27.6	.105	.76	Baa	.084	-1.5	.289	.567	.120
UGI Corp	.6	.126	1.10	A	.147	8.5	0	0	1.000
W. Penn Pwr	16.2	.145	.68	Aa	.163	25.0	.595	.132	.850
Rhode Island									
Narragan El	3.5	.103	.76	A	.118	.1	0	1.000	0
Newport El	.4	.048	N/A	N/R	.040	-9.2	.228	1.000	0
South Carolina									
S.C. El&G	11.8	.111	.78	A	.085	6.2	.502	.363	.480
Vermont									
Cent Vt Pub Serv	1.9	.104	.66	Baa	.178	8.2	0	.406	0
Green Mt Pwr	1.3	.159	.71	N/R	.244	14.8	0	.720	0
Virginia									
Va El & Pwr	39.2	.103	.58	Baa	.095	21.2	.367	.208	.330
West Virginia									
Appal Pwr	31.5	.120	.83	Ba	.151	37.1	.055	0	.850
Monong Pwr	9.3	.101	.68	Baa	.106	32.0	.301	0	1.000
Wisconsin									
Lake Sup. Dist Pwr	.7	.082	.77	A	.095	9.1	.168	.034	.690
Madison G&El	2.2	.123	.740	Aa	.136	42.6	0	.180	.610
N. States Pwr	3.1	.118	.77	Aa	.140	20.0	0	.719	0
Wisc El Pwr	17.7	.114	.71	A	.164	23.8	.246	.134	.630
Wisc Pwr,Lt	7.4	.130	.82	Aa	.158	34.9	.150	.081	.730
Wisc Pub Serv	6.7	.134	.76	Aa	.164	36.1	.536	.116	.690

Table 2. (Continued)

Notes

[1]The "standard" return on common equity equals net income minus preferred dividends for 1980 divided by proprietary capital minus preferred stock issued (the average value for 1979 and 1980). Data are from the 1979 and 1980 Statistics of Privately Owned Electric Utilities.

[2]The ratio of market price to book value equals the midpoint of the high and low prices for 1980 divided by book value. Data are from 1981 Standard and Poor Stock Reports. N/A means these values were not available.

[3]The bond ratings are those for each company's latest debt issue and are from Moody's 1981 Public Utility Manual. N/R indicates that the company's debt is not rated (usually privately placed).

[4]The "alternate" return on common equity equals 1980 net income minus preferred dividends minus AFUDC plus provision for deferred taxes (net) plus ITC adjustment, this quantity divided by proprietary capital minus preferred stock issued (the average value for 1979 and 1980). Data are from the 1979 and 1980 Statistics of Privately Owned Electric Utilities.

[5]The percentage change in kilowatt hour sales from 1973 to 1980 is computed from the 1973 and 1980 Statistics of Privately Owned Electric Utilities. It equals ((1980 sales)÷(1973 sales)) - 1.

[6]A company's percentage of projected capacity is its projected capacity divided by its total capacity. Data are from the 1980 Inventory of Power Plants in the U.S. published by the Department of Energy. Total capacity includes shutdowns and standbys but not retired, projected or cancelled plants. Under projected capacity, two American Electric Power plants totalling 2696 MW were allocated equally among the American Electric Power companies, since no ownership percentages were reported.

[7]The percentage of oil capacity equals the number of megawatts of oil burning (i.e. for which oil is the primary fuel) generating capacity divided by total capacity. The source is Ibid.

[8]The percentage of coal capacity equals the number of megawatts of coal burning (i.e. for which coal is the primary fuel) generating capacity divided by total capacity. The source is Ibid.

[9]Upper Peninsula Power Company is the distributing company for Upper Peninsula Generating Company (both have generating capacity) and so they are treated together.

[10]This utility has converted many plants to coal; its 1980 fuel mix was 73% coal and 20% oil (Standard and Poor Stock Reports, New York Stock Exchange, April 1982).

"speculative" ratings are geographically scattered: only one state, Pennsylvania, has as many as two (and one of these is Metropolitan Edison, owner of the Three Mile Island nuclear power plant).

Return on Common Equity. Turning to measures which pertain more directly to the market for common stocks, a standard measure of the return to common equity (ROCE) is a good place to begin. As computed in Table 2, it is the earnings available for common stockholders in 1980 (net income minus preferred dividends) divided by the average value (between 1979 and 1980) of common equity (proprietary capital minus preferred stock issued)[5/]. Devising a set of benchmarks for assessing these values is problematic, for common stocks of utilities have traditionally sold as sources of income rather than capital gains and have competed with bonds and other fixed income investments. Thus, their rates of return should probably be measured against interest rates, yet these have been extremely volatile in the past few years. An alternative set of guidelines is provided by the average allowed return (14.0%) and the average earned return (11.1%) for all utilities in 1980[6/]. The allowed rate of return may be taken to reflect the commissions' judgments of the rate desired by the market, and given that earned returns usually fall short of allowed returns, utilities which managed to exceed the average allowed return would seem to be extremely sound. As the following table makes clear, they are few:

Return on Common Equity	# of Utilities
more than 14.0%	9
more than 11.1%, less than 14.0%	47
more than 0%, less than 11.1%	47
less than 0%	3
	106

About half of the utilities in our sample (roughly the same number as earned Aa or A bond ratings) had greater than average returns, but short term government securities rates were frequently greater than 14.0% in 1980 and averaged 11.5%

for the year[7/], suggesting the kind of competition faced by utility stocks. No segmentation of the utilities with lower than average returns unequivocally picked out the most troubled companies unless the boundary was set at zero. A few states--Indiana, Iowa, Kentucky, Mississippi, Missouri, New Jersey, Ohio, and Wisconsin--had a high proportion of utilities (more than half) with above average returns. They comprise a smaller subset of the states with high proportions of bond ratings of A or better. Arkansas, Delaware, Georgia, Illinois, Maine, New York, Pennsylvania, Rhode Island, Virginia, and West Virginia are states where half or more of the utilities had lower than average earned ROCE's.

An Alternative ROCE. While this measure of return to common equity is the standard one and the proper one to compare with regulatory allowed rates of return, the peculiarities of utility accounting and the existence of large capital expenditures make it worthwhile to develop an alternative measure that, in a sense, tests the robustness of the standard one. Utilities' income statements include a non cash income item, Allowance for Funds Used During Construction (AFUDC), which is essentially the imputed cost of capital for current construction projects and which becomes a part of the rate base when a facility comes on line. Because it does not represent cash income, however, it may unduly inflate the ROCE of utilities with large construction programs. The financial markets have become increasingly sensitive to the distortions caused by this item. Another set of items which represents a current cash flow not recognized in the computation of net income are the tax savings from accelerated depreciation (which are positive in the early years of a project's life but become negative in later years as accelerated depreciation first exceeds and then becomes less than straight line depreciation) and from the investment tax credits which the utility has earned. These items may increase or decrease the funds available for common stockholders after depreciation and fixed charges and expenses. The alternative measure of ROCE simply subtracts AFUDC and adds the provision for deferred taxes and the investment tax credit adjustment to the numerator of the standard measure. The result, in Table 2, enhances ROCE for 72 utilities and diminishes it for 34. It might be surmised that utilities with diminished ROCE's would have large amounts of AFUDC and by implication, large current construction programs. A look at the column in Table 2 which gives the percent of projected new capacity bears this out to some extent, since 94% of these 34 utilities (compared with 79% of the total sample) have projected capacities that are greater than zero, and for 56% of them (compared with 42% for the total sample) the ratio of projected to total capacity is greater than .4. Utilities with small or nonexistent construction programs may experience diminished ROCE's if their plants are relatively old so that deferred taxes from accelerated depreciation have become liabilities. States with a high proportion of utilities for which the alternate ROCE is less than the standard ROCE are Louisiana, Michigan, Mississippi, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, and Virginia.

Market to Book Ratio. A final measure of utilities' position in the market for common stocks is their market price to book value ratio. The values for 1980 in Table 2 show the degree to which the market has recently devalued utility common stock: all but a few are substantially less than 1.0. (Though values for individual utilities are not available for a more recent year, Standard and Poor noted in January 1982 that a "substantial number" were selling below book value[8/].) This measure has declined steadily for all but one of the utilities since 1977, when 75% of this sample had ratios of greater than .9 and 42% had ratios greater than 1.0. This decline may be due partly to the substantial increases in interest rates during this period since, as noted above, utility stocks are substitutes for fixed income investments and their prices move counter to interest rates.

Depressed market to book ratios not only reflect utilities' difficulty in selling common stock but also make it harder to raise a given amount of capital by a new issue without diluting current stockholders' investment.

Debt and Equity Measures Viewed Together. Bringing together the data on bond ratings and common stock indicators suggests that these utilities' positions in the bond market have remained, on average, stronger than in the stock market, though the large number of rating downgradings in the past two years implies that many utilities have temporarily reached a limit on the amount of additional debt financing they can undertake. While 6 of 9 utilities with standard ROCE's greater than 14.0% had Aa or A bond ratings, high bond ratings and high standard ROCE's are far from perfectly correlated. For example, 5 utilities with Aa ratings and 13 with A ratings earned ROCE's of less than 11.1%. However, four of the five (and eight of the thirteen) had substantially higher ROCE's when the alternative measure was used. Some of the apparent lack of correlation between the bond ratings and returns on equity may then be due to the faulty nature of the standard ROCE measure and the fact that the market does adjust it for such items as AFUDC. Certain states have some utilities with both below average bond ratings and below average ROCE's: Arkansas, Connecticut, Georgia, Maine, Indiana, Massachusetts, Michigan, New Jersey, Pennsylvania, Virginia, and West Virginia.

Non Market Considerations. It is important to supplement these market measures with other factors that bear on utilities' financial health. Two such interrelated factors are sales growth and projected capacity (both in Table 2). Extremely high or extremely low sales growth may place financial pressures on companies: the former by requiring heavy expenditures on new plants (if reserve margins are low) and the latter by making it more difficult for utilities to recover the costs of completed facilities (higher rates may drive demand down further) and to finance projects currently underway.

To examine the second situation first, 22 of the utilities under consideration had a negative net percentage change in kilowatt hour sales from 1973 to 1980. Of these, 13 have some construction plans for new plant, as measured by projected over total capacity. As might be expected, all but one of these utilities has a bond rating or ROCE that is "below average" and most have below average values for both measures. The latter group particularly may be regarded as in great difficulty. Negative sales growth occurs in parts of Indiana and Illinois and is more pervasive in Michigan, Massachusetts, New York, and Pennsylvania.

Utilities with sales growth exceeding 30% (more than 4% per year) over this period show, as expected, much planned construction, but not as strong a correlation with ill financial health as the companies with declining sales. Of the 17 utilities in this group, all but one has some projected capacity and 10 have a ratio of projected to total capacity greater than .4. Yet 7 of these companies have bond ratings of Aa or A <u>and</u> above average ROCE's, while only 3 have bond ratings below A coupled with below average ROCE's. (The apparent good health of these 7 utilities must be viewed in the context of utilities' overall deteriorating position in the financial markets, however.)

<u>Summary</u>. Table 3 gives a summary of states which have particularly strong or particularly problematic utilities by some of the measures just discussed. While the categories are rough in that they are based on counting utilities without regard to their size, they do provide one quick way of picking out some extremes. For example, Indiana, Iowa, Kentucky, Mississippi, Missouri, New Jersey, and Wisconsin stand out as states with utilities that are financially strong, on average (Columns 1 and 2) (though this judgment must be tempered by noting that Indiana has two and New Jersey one very troubled utility (Column4)).

Table 3. State Summary--Financial

(1) More than half of utilities have Aa or A ratings	(2) More than half of utilities have ROCE's greater than 11.1%
Delaware	
Florida	
Illinois	
Indiana	Indiana
Iowa	Iowa
Kentucky	Kentucky
Minnesota	
Mississippi	Mississippi
Missouri	Missouri
New Jersey	New Jersey
New York	
Ohio	
Wisconsin	Wisconsin

(3) More than half of utilities have ROCE's less than 11.1%	(4) Some utilities have both bond ratings below A and ROCE's below 11.1%	(5) States with declining kilowatt hour sales, 1973-80
Arkansas	Arkansas	Michigan
Delaware	Connecticut	Massachusetts
Georgia	Georgia	New York
Illinois	Maine	Pennsylvania
Maine	Indiana	
New York	Massachusetts	
Pennsylvania	Michigan	
Rhode Island	New Jersey	
Virginia	Pennsylvania	
West Virginia	Virginia	
	West Virginia	

Columns 3 and 4 pick out the states with the most troubled utilities, on average: Arkansas, Georgia, Maine, Pennsylvania, Virginia, and West Virginia. States with negative demand growth and utilities that are not particularly strong--Michigan, Massachusetts, and perhaps New York--may also be of concern.

One general observation to keep in mind in concluding this portion of the financial overview is that high and increasing interest rates impede utilities' ability to raise capital in both the bond and common stock markets. It should be noted, however, that uncertainty about interest rates together with improved earnings were thought to contribute to utilities' outperforming the stock market Standard and Poor 500 in the first part of 1981[9/]. Given continued uncertainty about interest rates (due to the protracted Federal budget fight) and further increases in allowed ROCE's (see below) utilities' positions may have continued to improve (particularly the relatively strong ones), but as noted above, the market to book ratios of most remain low. Another general remark is that the financial community has become increasingly sensitive to the problems incurred by utilities with large construction commitments, and it may be that such companies are informally discounted by the market even before they encounter difficulties.

State Regulatory Policies and Climate

Because electric utilities are regulated monopolies whose rates are set by state agencies, the policies of these commissions are important determinants of utilities' financial strength and have implications for their ability to meet increased pollution control expenditures. Briefly, commissions determine rates in the following manner. The rate base, which consists of a utility's assets including AFUDC (discussed above, p. 14), is multiplied by the company's weighted average cost of capital to arrive at an allowed return on capital. The components of the weighted average cost of capital are the utility's capital structure, the embedded cost of debt and preferred equity, and finally, the return to common equity, which is determined by the commission. This return to capital plus depreciation and tax, fuel, and operating expenses comprise the revenue requirement, which is apportioned among the company's different classes of customers to determine the price per kilowatt hour charged to each group.

The policies considered in this study are summarized for each state in the ARMS region in Table 4[10/]. The first three policies affect the portions of the revenue requirement that are directly related to utilities' capital equipment investments and are thus most relevant to changes in the Clean Air Act that might require investment in FGD systems and other air pollution control equipment. Regulatory lag and the type of test year used--historical or forecast--affect primarily the operating and fuel expense components of revenue requirement and would therefore be relevant both for policies requiring FGD equipment (which has rather high and unpredictable maintenance expenses) and for policies which allow the burning of low sulfur fuels. The nature of the fuel adjustment clause is important, of course, for the low sulfur fuel option. We will treat it, in fact, as the primary regulatory determinant of utilities' ability to switch to low sulfur fuels without suffering financially and will defer discussing it until we examine that policy option in the next section. First we will discuss the other regulatory policies: their interrelations among themselves and their relation to the financial status of the utilities.

Allowed Return on Common Equity. The allowed rate of return to common equity is set by the regulatory commission. It is the one element of the weighted average cost of capital directly subject to its discretion and is typically larger than the embedded costs of debt or preferred stock. It is therefore a primary means of increasing utility rates and has been increasing

Table 4. Major State Regulatory Policies

state	allowed ROCE	amount of CWIP allowed in rate base	treatment of tax savings (ITC/deprec)	average number of months for rate decisions	type of test year
Alabama	12.85	100%	normalization	6	historical
Arkansas	15.0	100%	norm/part.norm	10	historical
Connecticut	14.8	0	part.norm/norm	5	historical
Delaware	15.0	100%	normalization	7	forecast
Florida	15.5	varies	normalization	8	forecast
Georgia	13.33	varies	normalization	6	forecast
Illinois	16.5	varies	norm/part.norm	11	forecast
Indiana	15.83	small %	normalization	6	historical
Iowa	13.35	0	normalization	12	historical
Kentucky	14.25	100%	normalization	10	historical
Louisiana	14.325	100%	normalization	12	historical
Maine	15.13	0	normalization	9	historical
Maryland	14.0	100%	normalization	7	forecast
Massachusetts	14.31	0	normalization	6	historical
Michigan	13.25	100%	normalization	9	forecast
Minnesota	14.0	100%	normalization	12	forecast
Mississippi	12.85	varies	normalization	6	forecast
Missouri	13.71	0	normalization	11	historical
New Hampshire	14.75	0	normalization	6	historical
New Jersey	14.0	varies	normalization	8	forecast
New York	15.5	small %	part.norm	11	forecast
North Carolina	13.87	100%	normalization	7	historical
Ohio	15.86	varies	normalization	9	forecast
Pennsylvania	15.63	small %	normalization	9	forecast
Rhode Island	14.13	0	normalization	8	historical
South Carolina	13.88	100%	normalization	12	historical
Vermont	14.5	small %	normalization	21	historical
Virginia	15.0	100%	normalization	5	historical
West Virginia	14.0	varies	normalization	10	historical
Wisconsin	12.72	small %	normalization	8.5	forecast

fairly rapidly in recent years: the average allowed return was 13.46% in 1979, 14.0-14.25% in 1980 and 14.5-15.5% in 1981[11/]. The most recent average rates allowed by states in the study (during the 1980-81 period) range from 12.72% to 16.5%, with a mean of 14.4%, slightly above the overall U.S. average for 1980. Due primarily to inflation and the several months' lag between application and approval for rate increases, the returns on common equity actually earned by utilities have lagged behind the allowed returns. However, earned returns have increased greatly in the last few years: in 1979 and 1980 the U.S. average earned rate of return on common equity was stagnant at 11.1%, in 1981 it was up to 12.0-12.5% and in early 1982 it ranged between 12.25 and 12.75%[12/].

CWIP in the Rate Base. Another way of affecting utility prices is by the inclusion or the timing of the inclusion of assets in the rate base. Traditionally, assets were not allowed in the rate base until they were fully constructed and actually used (and were kept in as long as they were "useful"). Given increasing construction costs, lengthening construction periods, and financially troubled utilities, however, many states have relaxed this dictum and have begun to allow part or all of current construction costs (Construction Work in Progress (CWIP)) in the rate base. This policy change has been controversial both because it means customers (the mobile and elderly, at least) may be paying for assets that never benefit them and because it may remove utilities' incentives to keep construction costs down and lead times short. Nevertheless, it is an effective short term way of helping utilities financially (so long as the utilities are not overbuilding and continue to control costs). Eleven of the 30 states under consideration allow 100% of CWIP in the rate base, 7 allow none, the remaining states allow "varying amounts" or "a small percent."

A question not asked directly in the survey of commissions but which has since been explored further is whether states are more likely to allow CWIP in the rate base if it is for pollution control equipment. A telephone sampling of 11 of the 30 states in March 1982 revealed that pollution control CWIP does not receive preferential treatment in these jurisdictions. The two states called (Iowa and Missouri) which allow no CWIP in the rate base maintain this policy for pollution control equipment as well. Of five states queried who allow a small percent, Vermont and Pennsylvania have included environmental CWIP, Indiana and New York have not, and Wisconsin shows no favoritism for specific types of investments. Neither the two states questioned who allow varying amounts of CWIP (Illinois and Mississippi) nor the two states who allow 100% (Minnesota and South Carolina) distinguish between pollution control equipment and other assets.

Accounting Treatment of Tax Savings. A third way in which regulatory policy may affect rates is in the treatment of corporate income tax savings earned by utilities from accelerated depreciation and the investment tax credit (ITC). Flow through accounting passes these savings on to consumers immediately. Normalization allows the utilities to make use of the tax savings temporarily by spreading out their remission to consumers over a period of time, typically over the life of the asset with which the tax saving is associated. Normalization therefore improves a company's cash flow somewhat during,and in the first years following,the large construction projects that generated the tax benefits. Since the Internal Revenue Service Code forbids utilities to take advantage of these tax savings unless they are normalized, it is not surprising that the vast majority of the states fully normalize (and this policy does not, therefore, serve well to distinguish states from one another). Changes in the ITC rate and in depreciation lives since this requirement was enacted, however, permit partial normalization, and four states in the ARMS region follow this intermediate policy. Only one state in the ARMS region, Tennessee, allows flow through accounting of the tax benefits (but its investor owned utilities are not included in the study (see Table 1)).

Regulatory Lag. Because of inflation "regulatory lag," the average number of months from the time a rate request is filed until the time it is ruled upon, has become an important factor in utilities' financial health, since expected costs at the time of the request may be far lower than at the time a rate increase is granted several months later. States in the ARMS region reported a range of 5 to 21 months for this period (the latter value an outlier). The average length of this period has shortened in recent years for the U.S. as a whole, from 11.5 months in 1979 to 8.75 months in 1980[13/].

Test Year. In setting rates, the components of the revenue requirement are computed for a sample or "test" year. Until recently, these computations were based entirely on historical information, but inflation, again, has prompted many commissions to experiment with the use of forecasted values for these costs. These forecasted values are sometimes the sole determinant of test year costs, or they may be used in combination with historical data in determining the components of the revenue requirement. Like regulatory lag, this aspect of policy is probably most crucial in determining how effectively utilities recover variable costs such as operating and fuel expenses, and the use of forecasted costs may mitigate a long rate determination process. The majority (17 out of 30) of the states under consideration still use a historical test year exclusively. The remainder make at least partial use of forecasted costs. Only 3 out of 11 states (Illinois, New York, and Minnesota) with greater than 10 month rate setting periods use a forecast test year to help offset regulatory lag.

Summary: Regulatory Climate. Just as the type of test year used may help substitute for a shorter rate setting period, so may quick decisions or allowing CWIP in the rate base substitute for a high rate of return (or a large ROCE compensate for no CWIP in the rate base). Thus it is necessary to look at a range of policies in order to gauge the regulatory climate of a state. Only a few states--Delaware, Maryland and Virginia--have extremely favorable policies across the board (allowed ROCE of at least 14.0%, 100% of CWIP allowed in the rate base, and a less than 10 month regulatory lag). (The regional interdependence of these states may account for the policy uniformity here.) Many states show some use of offsetting policies. Two states--Alabama and Michigan--have low allowed ROCE's but allow 100% of CWIP in the rate base; while Connecticut, Maine and New Hampshire have recently allowed very high ROCE's (greater than 14.5%) but allow no CWIP in the rate base[14/].

Summary

Perhaps surprisingly, there is not a complete correspondence between utility financial health and favorable regulatory climate. For example, among the states identified in the financial summary as having relatively strong utilities on average (Indiana, Iowa, Kentucky, Mississippi, Missouri, New Jersey, and Wisconsin), Iowa and Missouri have among the apparently "least favorable" regulatory climates (allowed ROCE less than 14.0%, no CWIP in the rate base, 11-12 month regulatory lags, and use of historical test year only). Indiana, Kentucky and New Jersey show the most favorable overall policies in the group--fairly high ROCE's, some flexibility in the inclusion of CWIP and fairly short regulatory lags--but none is as favorable as the "Delmarva" states noted above. (Kentucky's 10 month regulatory lag is offset by 100% CWIP in the rate base and a monthly fuel adjustment.) Wisconsin's and Mississippi's regulatory policies are favorably distinguished only by their short lags, use of forecast test year data and some flexibility in the inclusion of CWIP.

Looking at the states identified above as having a high proportion of troubled utilities (Arkansas, Georgia, Maine, Pennsylvania, Virginia, and West Virginia), 2 states (Arkansas and Virginia) have very favorable regulatory climates while both Pennsylvania and Maine have granted very high ROCE's and have relatively short lags. Perhaps the favorable policies are in part a response to the utilities' difficulties. Georgia's and West Virginia's policies have only one strong point each, a very short (6 month) lag in the former and a 14.0% allowed ROCE in the latter.

Thus, highly favorable regulatory climates are neither necessary nor sufficient in themselves for utilities' financial health, and other factors--managerial skills, regional economic strength, and lags between state policy implementation and effects on utilities--can have important effects.

II. The Fuel Switching Option

The primary burden to utilities from standards which would require or encourage them to burn oil or coal with a lower sulfur content is from the premium these fuels command. On the other hand, provisions known as fuel adjustment clauses have been enacted in most states in the ARMS region to enable utilities to recover more readily the increased fuel costs that have confronted them over the past decade. We will first discuss the evidence on current levels of sulfur premiums and on the likelihood of their rising further with increased demand. We will then relate these findings to utilities' abilities to bear these costs and to possible consumer costs in the ARMS region.

The Effect of Sulfur Content on Coal and Oil Prices

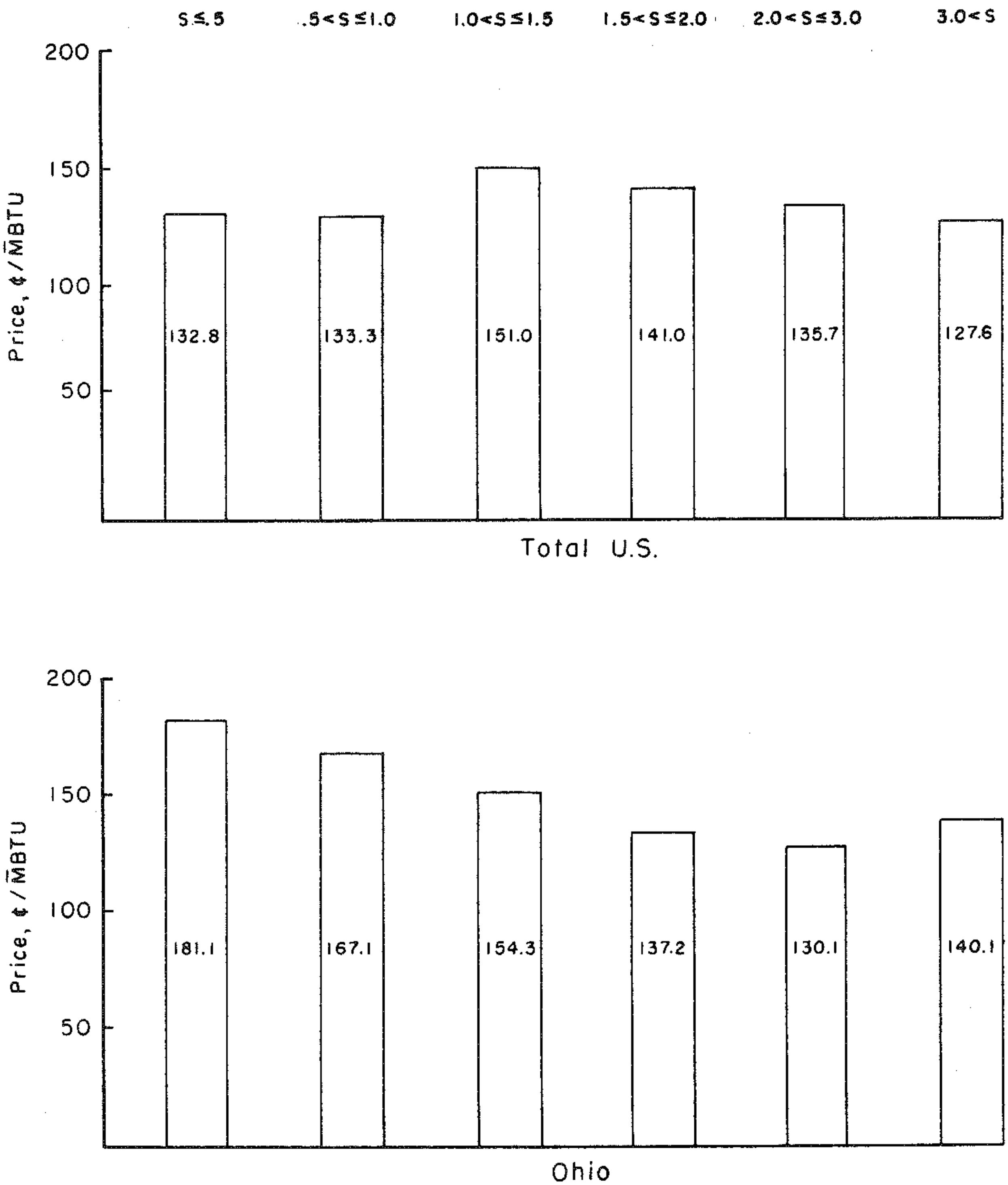
Most persons who work closely with the coal industry maintain that premiums for low sulfur coal probably exist, and the need for additional sulfur removing equipment at refineries suggests that there would be premiums on low sulfur oil as well. However, there has been relatively little analysis to determine whether such premiums exist and, if so, how large they are.

The most plausible hypotheses to account for the existence of sulfur premiums are (1) that low sulfur fuels have higher marginal production and transportation costs, on average, than those with greater sulfur content; (2) that the supply of lower sulfur fuels is so small that increasing scarcity caused by a rise in demand would induce continuing price increases; or (3) that firms in the industry have a degree of monopoly power and are thus able to maintain a price higher than marginal costs.

Coal premiums. The source of premiums for low sulfur coal is problematic. It is sometimes suggested that sulfur premiums in the long run would reflect the competing cost of sulfur removal systems. However, in a competitive fuel industry this could happen only if the cost of producing and delivering lower sulfur coal (or the price justified by resource scarcity) was as large as the cost of an FGD system designed to remove that amount of sulfur. If low sulfur fuel is in fact the less costly option, then a firm that tried to charge a fuel price equivalent to the cost of FGD removal would be undercut by rivals, and eventually the price would equal the marginal cost of the less expensive alternative. Only a degree of monopoly power in the fuel industry would result in a higher price in the long run.

Figure 1, which reveals higher prices for higher sulfur fuels in some categories, casts doubt on the notion that low sulfur fuel is always more costly to produce and deliver than high sulfur fuel. It is conceivable that increases in demand for low sulfur coal could result in short run premiums until new mines were developed. The current high ceilings on coal sulfur levels in many states and areas make it doubtful that such demand pressure currently exists, though lowering ceilings could bring it about. In the very long run, of course, resource depletion and increased demand would result in higher premiums, but long run supplies of low sulfur coal are very large: nearly 50 percent of U.S. coal reserves have less than 1 percent of sulfur by weight. Most of these reserves are located in Central Appalachia and the West (see Table 5 and Figure 2). Thus, only monopoly behavior could explain a high, permanent sulfur premium, yet there is no strong basis to suspect it in the

FIGURE 1. SULFUR CONTENT AND PRICE FOR TOTAL U.S. AND OHIO



Source: Costs and Quality of Fuels for Electric Utility Plants, 1980 Annual, U.S. Department of Energy

Table 5.

DEMONSTRATED* U.S. COAL RESERVES BY REGION AND COAL RANK

(million tons)

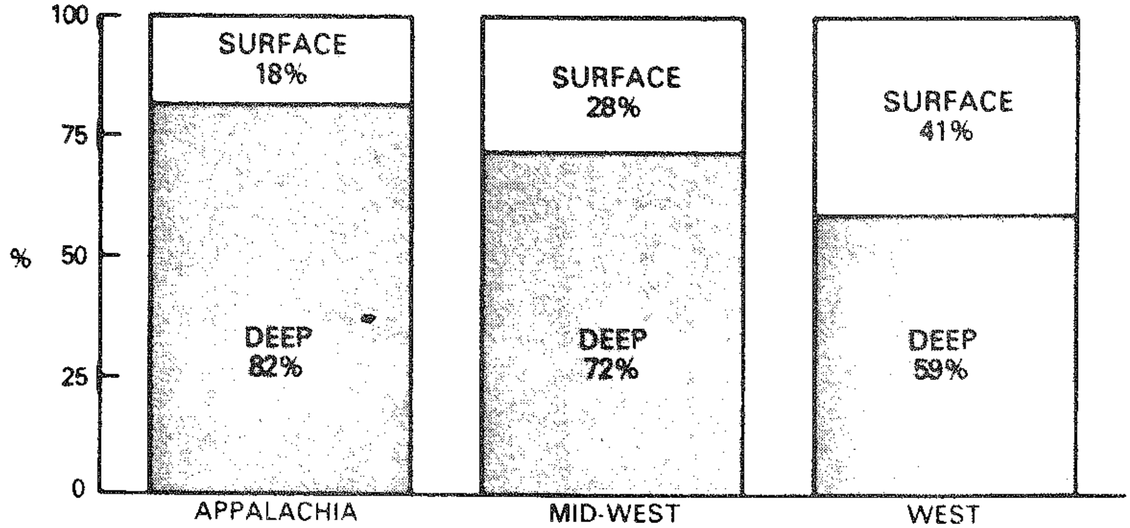
		COAL RANK				TOTALS	
		Bituminous	Sub-Bituminious	Anthracite	Lignite	Sub-Total	Grand Total
APPALACHIA	Surface	18,794	-	143	1,083	20,020	111,622
	Deep	84,498	-	7,104	-	91,602	
MID-WEST	Surface	26,108	-	8	3,208	29,324	104,502
	Deep	75,089	-	89	-	75,178	
WEST	Surface	1,951	60,686	-	28,900	91,537	221,558
	Deep	22,271	107,722	28	-	130,021	
TOTAL	Surface	46,853	60,686	151	33,191	140,881	
	Deep	181,858	107,722	7,221	-	296,801	
	Total	228,711	168,408	7,372	33,191		437,682

Demonstrated Reserves Potentially Mineable (as of January 1, 1976) 437,682

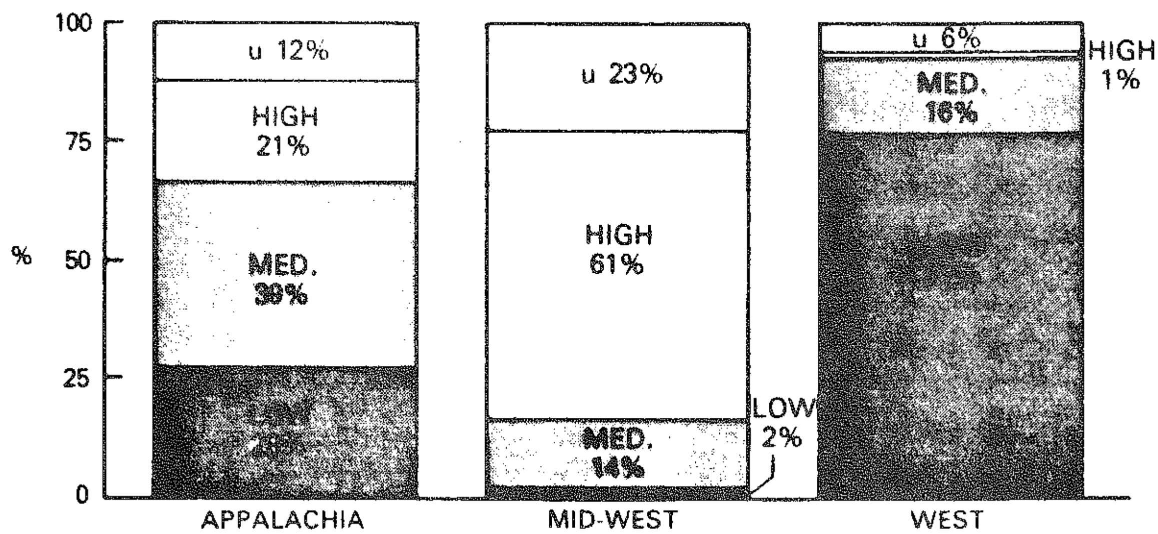
* **Measured and indicated deposits, half of which may be considered "recoverable" and are so designated.**

Source: U.S. Bureau of Mines, in Coal Data Book, February 1980, The President's Commission on Coal, p. 71.

Figure 2. **U.S. COAL RESERVES* — POTENTIAL METHODS OF RECOVERY**



U.S. COAL RESERVES* — SULFUR CONTENT



low sulfur	< 1%
medium sulfur	1.1 to 3%
high sulfur	>3%
u	unknown

* Demonstrated coal reserves.

Source: National Coal Association, in Coal Data Book, February 1980, The President's Commission on Coal, p. 75.

coal industry. First, the industry consists of a relatively large number of firms (a hindrance to enforcing price fixing among cartel members), and further, some large coal burning utilities supply their own coal (an option which is open in theory to other utilities), putting additional limits on suppliers' abilities to charge prices greater than marginal costs.

While these considerations question the basis for assuming large sulfur premiums and make their likely amount uncertain a priori, some studies have determined rather high values for low sulfur coal premiums. A study by Argonne National Laboratory concluded that there was a premium on 0.75% - 1.75% sulfur Pennsylvania coal of $4 a ton (1975$) (or about $7 per ton in 1982$)[15/]. This is roughly 15 percent of the average price of a random sample of Appalachian coal. This value is also in rough accord with a prediction of the President's Commission on Coal that low sulfur coal will command a $10 per ton premium by 1985 ($\$7 \times (1.09)^3 = \$9$)[16/]. Michael Le Blanc arrived at an even higher premium--50 percent of price--from a linear programming model that examined cases with and without strict sulfur controls[17/].

To provide some further perspective on this question, we have taken a different approach to identifying sulfur premiums by using some simple econometric models (described in detail in Appendix 2) to isolate the effects of sulfur content on price from the effects of other relevant variables. Figure 1, which shows that coals in a high sulfur category may sometimes cost more per Btu than coals in a lower sulfur category, illustrates why it is necessary to control for other factors that may influence coal price.

The first model uses 1980 cross sectional data from 42 states and a generalized least squares estimator to examine the effects of sulfur content (SCON), underground purchases (UNDR), contract purchases (CONT), ash content

(ASH), Btu content (BTU), and dummy variables to account for geographical regions (A1-A3) on coal price (COST) in ¢/$\overline{\text{M}}$Btu. The results (in Table 6) showed logical signs for the coefficients, a significant value for the F-statistic, and an R^2 of .45. On the basis of this model one would conclude that the sulfur premium was 7.261 ¢/$\overline{\text{M}}$Btu for each 1% decrease in sulfur content, a very low value in comparison to those of the studies cited above, since it amounts to only 5% of the mean coal price of the sample.

In an attempt to improve the explanatory power, a second model was constructed which held region constant and transportation costs roughly constant, since these factors may have a critical influence on coal prices. Model 2 uses only Appalachian coal producing states' shipments for observations, in order to keep region constant. (This area is most relevant for the study since it is the source of most ARMS region utilities' coal purchases.) To keep transport costs roughly constant, only data points representing shipments to adjacent states were used (thus ignoring both intrastate and more distant shipments). The same explanatory variables were used as in Model 1 (except for the regional dummy variables) but the dependent variable COST was measured this time in $ per ton. The resulting model (see Table 7) had much better explanatory power (an R^2 of .853) and suggests a sulfur premium of $3.62 per ton for each 1% decrease in sulfur content, which amounts to 7.5% of the mean coal price in the sample.

While further work would be useful, the preliminary models indicate that the sulfur premium may in fact be much lower than previous work has suggested.

Table 6. Model 1 Statistics*

Explanatory variable	Estimated coefficient	Standard error	T-statistic
C	70.082	31.896	2.197
SCON	- 7.261	2.847	-2.550
UNDR	0.293	0.170	1.722
ASH	- 4.007	1.448	-2.768
BTU	0.010	0.003	3.223
A1	13.009	5.903	2.204
A2	12.820	5.375	2.385
A3	-37.235	6.877	-5.414

Sum of squared residuals = 84281.6

Mean dependent variable = 132.789

Standard deviation = 37.093

R^2 = .448

F-statistic (7,104) = 11.369

*Six states were omitted from the analysis because no coal shipments were reported in 1980 in Idaho, California, Vermont, Rhode Island, Maine, Connecticut. Alaska and Hawaii are excluded from the contiguous U.S. The maximum likelihood iterative technique of GLS was used in the estimation.

Table 7. Model 2 Statistics

Explanatory variable	Estimated coefficient	Standard error	T-statistic
C	1.710	18.643	0.092
SCON	-3.620	0.678	-5.340
UNDR	0.015	0.017	0.889
BTU	0.004	0.001	3.088
ASH	-0.967	0.275	-3.518
CONT	0.063	0.016	4.026

Sum of squared residuals = 388.846

Mean of dependent variable = 48.327

Standard deviation = 8.330

R^2 = .853

F-statistic (5,33) = 34.689

<u>Oil Premiums</u>. The basis for a sulfur premium on oil would appear to be cost, since a special process is required to extract the sulfur from crude oil. We have examined cost estimates for two refinery-level sulfur removal processes.

The first is the Ford, Bacon and Davis technique, which uses a sulfur recovery unit to remove hydrogen sulfide (H_2S). The first step of the process, called amine treatment, involves using an amine (e.g., isopropyl amine) to absorb H_2S in the crude oil and taking the absorbed H_2S to a stripper tower where the partially cleaned gas continues on for tail-gas treatment and the H_2S is sent to the sulfur recovery unit. The next step is to turn the H_2S into a high-quality molten sulfur product which can be sold. The Claus recovery unit can recover 94-97% of the sulfur in the H_2S. Since the U.S. Environmental Protection Agency requires 99% sulfur recovery, the third and final step involves tail-gas treatment of the flue gas not completely cleaned of sulfur.

Sam Hallett of the Ford, Bacon and Davis Corporation reports that for a process able to recover 100 tons per day of sulfur for a refinery processing about 64,000 bbl/day, the capital cost would be approximately \$12 million. (These figures are not precise cost estimates.) Given an average Btu content for fuel oil of 140,000 Btu per gallon, the levelized capital cost of the sulfur recovery unit using a .17 capital recovery rate would be 1.5¢/$\overline{\text{M}}$Btu (equals (12,000,000)(.17)/(64,000)(140,000)(42)(10^{-6})). Since this represents only .26% of the 1980 U.S. average fuel oil price of 590.0¢/$\overline{\text{M}}$Btu, the cost of the sulfur recovery unit appears to be extremely small. Even if operating and maintenance expenses were to quadruple this cost to 5.9¢/$\overline{\text{M}}$Btu, it is still a very small fraction of the price of oil. Comparing the refinery's levelized capital cost with that of an FGD system designed to remove 90% of the sulfur from oil burned at a 400 MW utility plant (52.0¢/$\overline{\text{M}}$Btu (1982\$), given a capital cost of \$140/KW (1980\$))[18/] indicates that for this process, sulfur removal at the refinery level is far more cost effective than at

the utility level.
The second sulfur removal pro
system (HDS), which an Environment
the most commonly used system in
remove nitrogen and metals, as we
the following

E.		274	1.17 (1.65)	2.45 (3.46)	(5.	
Kuwa	3.80	60	1.80 (2.54)	2.49 (3.53)	3.14 (4.43)	3.51 (4.95)
Khafji	4.36	118	2.20 (3.11)	2.85 (4.02)	3.60 (5.08)	4.11 (5.80)
Cold Lake	4.55	236	2.52 (3.56)	3.42 (4.83)	4.53 (6.39)	5.84 (8.24)

1/ Costs are expressed in $/bbl, for a 50,000 bbl/stream day residual oil feed. 1982 costs are in parentheses, assuming a 9% inflation factor per year.

2/ Ni = Nickel, V = Vanadium

Source: EPA, Technology Assessment: Oil Cleaning, p. 109.

:ess we considered is the hydrodesulfurization .al Protection Agency study has identified as the U.S.[18a/] This technique uses hydrogen to .. .ell as sulfur compounds, and must be used with .. auxiliary systems: a hydrogen sulfide absorption unit (circulating amine type), a sulfur recovery unit with tail gas scrubber, a sour water stripper, and a hydrogen plant. One disadvantage of HDS is its rather high consumption of energy: about 2-4% of the oil processed. The costs of the system are a function not only of sulfur content but of crude oil source and metal content, and costs increase disproportionately as the percentage of sulfur removal increases.

Table 7a, which summarizes capital and operating costs for five representative feedstocks, illustrates these points. In 1982\$, the costs range from \$1.28/bbl to \$8.24/bbl (\$.23/$\overline{\text{M}}$Btu to \$1.48/$\overline{\text{M}}$Btu, assuming a Btu content for oil of 140,000 per gallon). To compare these costs with utility level sulfur removal we must add FGD operating costs to our previous \$.52/$\overline{\text{M}}$Btu capital cost estimate. The source for the capital cost value gives operating costs for that system of 3.9 mills/kWh (1982\$). Assuming a 60% capacity factor for the plant, this cost is equivalent to \$.38/$\overline{\text{M}}$Btu (equals (\$.00392)(400,000)(.6)(8766)/(3.7)(140,000)(42)). Thus, the total FGD cost is \$.90/$\overline{\text{M}}$Btu. Since this FGD system is for 90% removal from a 2.2 lb SO_2/$\overline{\text{M}}$Btu input, the appropriate values in Table 7a for comparison are those for removal to .3% from the two lower sulfur oils (see Tables 3.1 and 11 for the sulfur input assumption and its conversion to a percentage). The costs are around \$.94/$\overline{\text{M}}$Btu, close to but slightly greater than the cost at the utility level. However, the cost of 90% removal for higher sulfur (but lower metal content) oil is only \$.75/$\overline{\text{M}}$Btu.

While sulfur removal at the refinery level using this process does not have the large cost advantage which the Ford, Bacon and Davis technique appears to enjoy, it may still be marginally preferable to remove sulfur at the refinery rather than at the utility level, given that refinery equipment is currently in place.

The difference between the costs for the two systems is extremely large. One factor may be that the removal of nitrogen and metals by HDS contributes something to the cost differential, although the two processes appear to be similar and are primarily designed for sulfur removal. Another possibility is that the capital cost estimates for the Ford, Bacon and Davis technique are unrealistically low (this is a likely bias when the information is gained from a supplier of the equipment). The HDS costs do include operating costs, which account for about 75% of the costs, but this still leaves a large discrepancy. The HDS cost estimates in Table 7a do include a credit for selling sulfur as a byproduct, so this cannot account for any of the difference in cost.

The cost figures even for a 90% reduction in sulfur with an HDS would imply that a sulfur premium for oil exists but is not a large percentage of price. A third model, similar to those for coal (and described also in Appendix 2) was estimated in an attempt to determine the effect of sulfur content on oil price. This model included all states which reported fuel oil receipts in 1980. The explanatory variables were heating value (HV), sulfur content (SCON), and regional dummy variables; the price of oil was given in ¢/$\overline{\text{M}}$Btu. The F-statistic and the T-statistic for sulfur content were significant (see Table 8) but the T-statistics for the other variables were not (though all the coefficients had logical signs). The R^2 was equal to .64.

Table 8. Model 3 Statistics*

Explanatory variable	Estimated coefficient	Standard error	T-statistic
C	94.889	484.638	0.196
SCON	-57.704	6.775	-8.517
HV	0.003	0.004	0.766
D1	14.875	15.708	0.947

sum of squared residuals = 65488.0

mean of dependent variable = 400.918

standard deviation = 63.009

R^2 = .641

F-statistic (3,43) = 25.041

*a) The following sulfur ranges were established:

Sulfur Category	Range (%)	Midpoint
1	< .3	.15
2	.3 < S < .5	.40
3	.5 < S < 1.0	.75
4	1.0 < S < 2.0	1.50
5	2.0 < S < 3.0	2.50
6	> 3.0	3.50

b) the minimum cutoff for size of the shipment was for 400,000 bbls.

c) Vermont, Indiana, N. Dakota, N. Carolina, West Virginia, Alabama, Kentucky, Tennessee, Oklahoma, Idaho, Montana, Wyoming, and Oregon were excluded. No fuel oil receipts reported in these states in 1980.

Though more work should be done to identify the "phantom variables" influencing price[19], the model at least provides a preliminary estimate of the sulfur premium: 57.7¢/$\overline{M}$Btu for a 1% decrease in sulfur content. The first thing to notice is that this is 14.4% of the mean price in the sample, a relatively larger premium than for coal. Second, it is far higher than the levelized cost for the Ford, Bacon and Davis technique (5.9¢/$\overline{M}$Btu, assuming operating costs three times the levelized capital cost). In addition, it exceeds the costs for the HDS technique. Taking the highest sulfur feedstock (4.55%) in Table 7a (to consider the most expensive case), the reduction to 1.6% sulfur costs \$.605/$\overline{M}$Btu compared to the \$1.73/$\overline{M}$Btu sulfur premium implied for an equivalent reduction (i.e., 3 (\$.58)); a reduction to .1% sulfur by HDS costs \$1.48/$\overline{M}$Btu, compared with a \$2.60/$\overline{M}$Btu sulfur premium (4.5 (\$.58)). This suggests that the 57.7¢ premium may be an upper limit. An alternative interpretation is that there may be monopolistic elements in the refining industry, enabling it to extract a higher premium than marginal costs would justify. Ownership of refineries exhibits a high degree of regional concentration, giving some plausibility to this hypothesis. The top four refinery owners in each state (with one or more refiners) owned 90% of the refinery capacity in that state[20]. Such institutional influences in utility fuel oil markets cannot be reflected by the ordinary statistical cost functions discussed here.

Effects of Premiums on Utility and Consumer Costs

To give some idea of the effects of sulfur premiums on costs to utilities and consumers in different states, Tables 9 and 10 present the average total fuel cost and average customer cost for each state, based on 1980 fuel purchases, the average sulfur content of oil or coal in each state, and the

Table 9. Representative Costs for Coal Switching - 50% Reduction, $3.6/ton premium

state	additional fuel cost million 1980 $[1]	average state additional fuel cost 1980 mills/kWh[2]	average state additional fuel cost 1982 mills/kWh[3]	average % S 1980[4]	1980 coal purchases 000 tons[5]	1980 generation, IOU's mil kWh[6]
Alabama	56.8	1.45	1.72	1.59	19838.4	39120
Arkansas	2.2	.13	.15	.38	3275.1	17319
Connecticut	--	--	--	--	--	24664
Delaware	3.0	.49	.58	1.54	1082.9	6166
Florida	34.1	.42	.50	2.18	8684.0	81978
Georgia	71.0	1.16	1.38	1.85	21306.6	61148
Illinois	118.9	1.19	1.41	1.84	35887.7	100109
Indiana	173.6	2.54	3.02	2.62	36816.8	68237
Iowa	20.8	1.02	1.21	1.08	10706.7	20837
Kentucky	112.5	4.89	5.81	2.51	24896.5	22987
Louisiana	1.6	.04	.05	.44	2067.9	41393
Maine	--	--	--	--	--	7884
Maryland	17.7	.55	.65	1.64	6001.9	32076
Massachusetts	1.3	.04	.05	1.16	633.5	34331
Michigan	51.8	.74	.88	1.30	22144.7	70358
Minnesota	20.7	.68	.81	.94	12233.4	30257
Mississippi	11.1	.68	.81	1.64	3751.4	16265
Missouri	117.0	3.26	3.87	2.62	24811.7	35881
New Hampshire	4.8	.80	.95	2.54	1052.3	5971
New Jersey	7.5	.26	.31	1.66	2525.9	29130
New York	21.1	.28	.33	1.84	6368.1	75162
North Carolina	40.5	.37	.44	.96	23433.9	70685
Ohio	227.5	2.08	2.47	2.49	50766.1	109201
Pennsylvania	160.6	1.31	1.56	2.11	42273.2	122496
Rhode Island	--	--	--	--	--	962
South Carolina	20.5	.62	.74	1.41	8096.4	33131
Vermont	--	--	--	--	--	3691
Virginia	8.2	.24	.29	.88	5202.4	33736
West Virginia	98.5	1.39	1.65	1.79	30580.1	70795
Wisconsin	48.9	1.47	1.75	1.87	14514.2	33314

Notes to Table 9:

[1]equals $\dfrac{.5(\text{average \% S})(\text{1980 coal purchases})(\$3.6)}{(1000)}$

[2]equals $\dfrac{(\text{additional fuel cost})(1000)}{(\text{1980 generation})}$

[3]equals $(\text{average state cost in 1980 mills/kWh})(1.09)^2$

[4]from Cost and Quality of Fuels for Electric Utility Plants, 1980 Annual, U.S. Department of Energy, Table 54, pp. 88 ff.

[5]Ibid., Table 29, p. 47.

[6]Statistical Yearbook of the Electric Utility Industry, Edison Electric Institute, 1980, Table 16, p. 25.

Table 10. Representative Costs for Oil Switching - 50% Reduction

$.577/$\overline{\text{M}}$Btu premium

state	additional fuel cost million 1980 $[1]	average state additional fuel cost 1980 mills/kWh[2]	average state additional fuel cost 1982 mills/kWh[3]	average % S 1980[4]	1980 oil purchases 000 tons[5]	1980 generation, IOU's mil kWh[6]
Alabama	.176	.005	.006	.28	2182.6	39120
Arkansas	7.331	.423	.503	1.18	21536.5	17319
Connecticut	16.751	.679	.807	.44	131962.5	24664
Delaware	9.684	1.571	1.867	.90	37296.5	6166
Florida	198.538	2.422	2.878	1.48	464982.7	81978
Georgia	3.209	.052	.062	1.74	6393.2	61148
Illinois	16.020	.160	.190	.66	84136.3	100109
Indiana	.392	.006	.007	.29	4682.0	68237
Iowa	.043	.002	.002	.20	739.0	20837
Kentucky	.059	.003	.004	.23	885.8	22987
Louisiana	11.545	.279	.331	.86	46532.1	41393
Maine	8.304	1.053	1.251	1.33	21643.0	7884
Maryland	20.354	.635	.754	1.20	58793.5	32076
Massachusetts	135.912	3.959	4.704	1.67	282096.5	34331
Michigan	10.882	.155	.184	.65	58027.4	70358
Minnesota	1.408	.047	.056	.99	4928.7	30257
Mississippi	24.279	1.493	1.774	2.61	32243.9	16265
Missouri	1.457	.041	.049	1.05	4810.7	35881
New Hampshire	12.849	2.152	2.557	1.93	23075.7	5971
New Jersey	10.635	.365	.434	.40	92155.2	29130
New York	131.539	1.750	2.079	1.24	367693.2	75162
North Carolina	.140	.002	.002	.22	2213.9	70685
Ohio	1.925	.018	.021	.53	12588.0	109201
Pennsylvania	24.354	.199	.236	.65	129871.0	122496
Rhode Island	2.354	2.447	2.907	.94	8683.2	962
South Carolina	8.724	.263	.312	2.03	14896.2	33131
Vermont	.017	.005	.006	.40	148.4	3691
Virginia	35.377	1.049	1.246	1.31	93605.5	33736
West Virginia	.185	.003	.004	.30	2142.2	70795
Wisconsin	.213	.006	.007	.23	3209.0	33314

Notes to Table 10:

[1]equals $\dfrac{.5(\text{average \% S})(\text{1980 oil purchases})(\$.577)}{(1000)}$

[2]equals $\dfrac{(\text{additional fuel cost})(1000)}{(\text{1980 generation})}$

[3]equals (average state cost in 1980 mills/kWh)$(1.09)^2$

[4]from Cost and Quality of Fuels for Electric Utility Plants, 1980 Annual, U.S. Department of Energy, computed from Table 56, pp. 110 ff, by averaging by quantity over the companies in the study.

[5]Ibid., Table 41, p. 64.

[6]Statistical Yearbook of the Electric Utility Industry, 1980, Edison Electric Institute, Table 16, p. 25.

premiums from our models 2 and 3 ($3.60/ton for coal and $.577/$\overline{M}$Btu for oil). The hypothetical policy is a 50% reduction in average sulfur content for each state. (See calculation method in table footnotes.) Both the approach and policy are merely illustrative and ignore the complexities of varying sulfur levels and policy ceilings within states, though we will briefly discuss below how these data might be used to examine the general effects of other types of policies.

Before discussing costs, it may be useful to consider the average sulfur content of fuels used in the various states and how they may be translated into lb SO_2/$\overline{M}$Btu, another common unit for expressing policy limits (state ceilings for older plants are often expressed in terms of allowed percentages of sulfur in fuel inputs, whereas new plant standards which may involve FGD equipment are typically expressed as a limit on output in terms of lb SO_2/$\overline{M}$Btu). The calculation methods and results for some typical values are presented in Table 11. Note that coal must be of much lower sulfur content than oil to meet a given SO_2 requirement. Looking at Table 9 (coal) and noting for reference that New York has a 3.8 lb SO_2/$\overline{M}$Btu limit for the more rural parts of the state and a limit of 1.2 lb SO_2/$\overline{M}$Btu in more urban areas[21/], a number of states (mostly coal producers as well) exceeded the higher value in 1980. (This may be either from higher ceilings in those states or from noncompliance.) Ceilings on sulfur in oil range from .3% in New York City to 2.0% in rural areas[22/]. Comparing Tables 9 and 10, the average sulfur content of oil translates into lower lb SO_2/$\overline{M}$Btu over all states than does the sulfur content of coals. All states but one have an average lb SO_2/$\overline{M}$Btu of less than 2.6 for all their oil plants, compared with only one quarter of the states when coal plants are considered. (Some states have higher ceilings for coal than for oil, which

Table 11. Relation of Sulfur in Fuels to Production of SO_2*

	% S in fuel	lb SO_2/$\overline{M}$Btu
coal	.64	1.2
	1.38	2.6
	2.03	3.8
oil	1.10	1.2
	2.43	2.6
	3.56	3.8

*The following U.S. average values from the 1980 Annual Cost and Quality of Fuels for Electric Utility Plants were used.

Coal: 135.1 ¢/$\overline{M}$Btu, \$28.77/ton, 1.60% S, and 21.3 $\overline{M}$Btu/ton

Oil: 435.1 ¢/$\overline{M}$Btu, \$26.96/bl, 1.03% S, and 6.17 $\overline{M}$Btu/bl accounts for some of the discrepancies[23/].)

Considering now the cost burdens that would result from a hypothetical 50% reduction in the average sulfur content in each state, it is clear that states with both a high current level of sulfur content and large use of the fuel will incur the greatest total additional fuel cost (column 1 in each table). The cost expressed in mills per kWh spreads this amount over all kilowatt hours generated in the state, and thus represents a "typical consumer's" cost increase only if the state generates most of its electricity from that fuel. The additional cost for either the coal or the oil premium is, however, only a very small percent of the typical residential electric rate of 50-70 mills per kWh.

Given the uncertainty regarding the levels of sulfur premiums and the preliminary nature of the models on which Tables 9 and 10 are based, we should consider at least the range in cost increases that would result from other assumptions concerning the amount of the premium. The range for oil with our assumed \$.577/$\overline{\text{M}}$Btu premium (14.4% of oil price) is .002-4.704 mills/kWh. To examine a premium equal to 45% of price, we can just triple these values to get a range of .006-14.112 mills/kWh. Now the higher value represents roughly 25% of the average residential electricity rate. To examine different values for the coal premiums we can start with the range for the \$3.60/ton premium (7.5% of coal price), which is .05-5.81 mills/kWh, and double it to get the costs of the Argonne estimate of \$7/ton, a range of .10-11.62 mills/kWh. Multiplying these values by 3 would give the costs of a 45% premium: .3-34.86 mills/kWh. Here the higher value is nearly 60% of the average electric rate.

These data may also be manipulated to examine different types of policies. The policy of a required 50% reduction in the average percentage of sulfur in both oil and gas for all states is obviously an unlikely one. As we have noted, ceilings for oil and gas differ within states, and given the greater reduction in sulfur that has already been achieved for oil, it is unlikely that further requirements for oil would be as stringent as those for coal. Also, ceilings or percentage reduction requirements are likely to vary between states.

The calculations in these tables can be redone to account for different types of policies. The crucial calculation is for total additional fuel cost, which equals

$$PC(\text{average sulfur }\%)(\text{fuel purchases})(\text{premium})$$

where $0 < PC < 1.0$ and equals the percentage reduction required ($PC = .5$ in these tables). To look at a policy which lowers the ceiling the equation could be written

$$(\text{average sulfur }\% - C)(\text{fuel purchases})(\text{premium})$$

where C is the new ceiling; if (average sulfur % - C) ≤ 0, then the state is already in compliance (on average, of course) and incurs no additional fuel cost.

While these calculations obscure much complexity in their averages, they give a general idea of how states (their utilities and customers) may be variously burdened by sulfur premiums.

Our feeling, from evidence on coal supplies and refining costs, is that actual premiums may well be nearer to the low end of the range we have considered and that they are unlikely to increase greatly even with increased demand (unless our missing explanatory variables include monopolistic influences). However, if they should turn out to confirm the pessimistic estimates, it would be well to consider what kind of burden this will place on utilities. Additional premiums from more stringent policies could be significant even using the lower premium values, as evidenced by additional fuel costs of more than $100 million in several states which are heavy users of oil or coal.

Effects on Utilities' Financial Positions

The frequency of electric rate changes allowed by states' fuel adjustment clauses and the extent of utilities' use of relatively high sulfur fuels will be the main determinants of how easily companies could switch to lower sulfur fuels without increased financial hardship.

Table 12 gives the percentage of oil and coal capacity in each state for the utilities in the study, the percentages of generation by oil and coal, and the frequency of rate adjustment allowed by each state's fuel adjustment provisions. (Table 2 gives the percentage of oil and coal capacity for each utility.) It seems obvious that utilities regulated by states that allow a regular monthly rate adjustment or allow irregular adjustments as needed (with an annual reconciliation) will suffer no direct additional financial hardship from having to pay premiums for low sulfur fuel. Sixteen of the 30 states have such policies. The remaining states need to be examined individually, referring to the range of financial and regulatory data in Tables 2 and 4 and to the data on costs.

Alabama has little oil capacity but its one utility included in the study does have 62% in coal capacity and is not particularly strong financially: it has a Baa bond rating and its ROCE is only slightly above average (though the alternate measure is significantly higher). It has only a very small construction program, however. In all, given that the fuel adjustment is quarterly and that Alabama has a short regulatory lag for recovering other costs, its utility should

Table 12. Fossil Fuel Capacity and Fuel Adjustment Provisions

state	% oil generation[1/]	% oil capacity[2/]	% coal generation[1/]	% coal capacity[2/]	frequency of adjustment
Alabama	0.0	2.0	77.2	62.0	quarterly
Arkansas	10.0	40.0	0.0	0.0	monthly
Connecticut	51.1	97.0	0.0	0.0	monthly
Delaware	53.6	56.0	36.1	37.0	monthly
Florida	46.2	68.0	20.6	20.0	monthly
Georgia	.8	15.0	78.5	73.0	quarterly
Illinois	7.0	24.0	64.7	61.0	irregular--as needed
Indiana	.5	6.0	98.6	81.0	quarterly
Iowa	.3	20.0	81.4	62.0	monthly
Kentucky	.2	2.0	94.4	94.0	monthly
Louisiana	10.5	16.0	0.0	0.0	monthly
Maine	26.0	70.0	0.0	0.0	quarterly
Maryland	15.6	45.0	45.3	22.0	monthly
Massachusetts	84.1	71.0	5.1	1.0	quarterly
Michigan	7.5	24.0	67.4	55.0	monthly
Minnesota	.7	13.0	63.6	62.0	monthly
Mississippi	18.0	17.0	37.6	29.0	monthly
Missouri	.5	15.0	96.0	76.0	no clause
New Hampshire	39.6	59.0	45.8	37.0	quarterly or monthly
New Jersey	29.8	52.0	21.8	17.0	irregular--as needed
New York	34.8	70.0	13.3	13.0	monthly
North Carolina	.3	9.0	83.9	60.0	3 times a year
Ohio	.9	10.0	96.8	82.0	biannual
Pennsylvania	8.8	27.0	80.6	56.0	yearly
Rhode Island	85.8	100.0	0.0	0.0	quarterly
South Carolina	3.7	36.0	46.6	48.0	biannual
Vermont	.6	63.0	.3	0.0	no clause for lg. utilities
Virginia	24.5	21.0	39.0	33.0	biannual
West Virginia	.6	0.0	98.8	90.0	biannual
Wisconsin	.7	17.0	65.9	61.0	monthly

[1/]For all states except Arkansas and Alaska, the percent oil or coal generation is computed from Table 22 of Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1980. While this is the only ready source of the data by state, the numbers are for the total industry, including cooperatives and government-owned plants as well as investor-owned utilities (IOU's). This causes problems for states with a significant percentage of generation from non-IOU plants: New York (30%), South Carolina (20%), Florida (15%), Kentucky (more than 50%), Alabama (50%), and Missouri (25%). In Kentucky and Missouri, generation from all sources is nearly 100% by coal, so the percentages in the Table are probably not biased. The Florida percentages are probably fairly accurate since public and private ownership is evenly distributed over the various forms of generation (see Tables 15 and 16, Ibid.). In New York, South Carolina, and Alabama, however, public and private ownership is unbalanced. In New York, a higher proportion of nuclear and hydro is publicly

(continued)

rather than privately owned, so the coal and oil percentages in the Table are understated. In South Carolina, the private sector generates all of the nuclear power and the public sector a proportionately higher portion of steam so that the percentages in the Table are somewhat higher than they would be if only the IOU's were considered. Alabama has a disproportionate public ownership of nuclear generation; since it has negligible oil generation, the percentage of coal generation in the Table is computed as the percentage of conventional steam generation for IOU's from Table 16, Ibid. Finally, Arkansas' only coal plant is publicly owned, so that although the state has some coal generation, it is not considered in this study. In summary, the numbers for New York and South Carolina should be viewed with some caution.

2/ Based on DoE, Inventory of Power Plants in the U.S., 1980, for plants where coal is the primary fuel for the investor owned utilities listed in Table 1.

not be in serious additional difficulty from cost premiums.

Georgia, with a quarterly adjustment, has one utility that seems to be in difficult financial circumstances. While the Department of Energy Inventory of Power Plants reported it to have more than 80% coal capacity, another source indicates that it has converted many plants to coal and had a fuel mix in 1980 of 73% coal, 20% oil and 7% gas[24/]. This utility is already burning coal with an average sulfur content of only .94%, however, which would mitigate the impact of more stringent requirements or a sulfur premium[25/]. Georgia's other utility has a high percentage of coal capacity. Although its bond rating is rather low, it has managed to earn a very high return on equity (which is enhanced further by the adjustments of the alternate measure) and would not seem to have great difficulty switching to lower sulfur fuels.

Indiana allows a quarterly adjustment also and has an extremely high percentage of coal capacity. It uses coal with a rather high average sulfur content, and as indicated in Table 9, could experience rather large increases in fuel costs from more stringent requirements. All but two of the companies are quite strong financially and should have no difficulty with the short lag in passing on fuel costs. One of those in difficulty had zero net income in 1980 and has had a net decline in sales since 1973. Even a short lag in recovering costs could be a burden. The other had experienced substantial demand growth from 1973 to 1980 and has a sizeable construction program but also has only 40% coal capacity, the lowest percent in the state.

Maine has a quarterly adjustment and utilities with substantial oil capacity. Only one has rated bonds (and those at Baa) and all have below average ROCE's, though these are much larger under the alternate measure. The largest utility has a rather sizeable construction commitment, possibly intended to reduce its dependence on oil, given that demand growth in recent years would not seem to warrant additional capacity. This utility in particular may find sulfur premiums a burden even though Maine adjusts rates for fuel costs fairly frequently.

Massachusetts likewise has a quarterly adjustment and utilities that are almost exclusively oil burning. About half are fairly healthy financially, though one of these has a large construction program that might cause cash drains in addition to those from oil premiums. One utility currently appears to be in great difficulty (Holyoke Water Power); and Fitchburg Gas and Electric, with a below average bond rating and ROCE and negligible demand growth, has a very large construction program. Boston Edison is in a similar position, with a smaller but still substantial ratio of projected to total capacity. Though Western Massachusetts Electric has a below average bond rating and ROCE it has no planned construction and less than 30% oil capacity and so should not be in any additional trouble, since premiums may be passed on quarterly. As many as three of Massachusetts' utilities, then, could find a few months' lag to be some burden as premiums augment cash drains from construction projects or add to an already severe financial situation. Table 10 indicates that Massachusetts is likely to experience higher additional fuel costs from oil premiums than other oil burning states.

Missouri represents the extreme case of a state with no fuel adjustment clause--fuel costs must be recovered through normal rate hearings[26/]. Further, Missouri has an average regulatory lag of 11 months and uses an historical test year exclusively. Table 9 shows that sulfur premiums would be relatively large here since all its utilities have high percentages of fossil capacity and on average burn coal with a high sulfur content. All are fairly strong financially and have some projected capacity: one with a ratio to total capacity greater than 1.0, the rest between .2 and .4. Given Missouri's array of policies, the companies' high percentage of fossil fuel capacity, and their commitment to cash-draining construction programs, all could find their financial positions eroded if faced with high and increasing sulfur premiums.

North Carolina allows adjustment of rates for fuel costs three times a year. Its utility with the greatest oil plus coal capacity is relatively sound financially. The other, Duke Power, has 61% coal capacity and rather weak values of the financial measures, when the alternate ROCE is considered, perhaps because of its extremely ambitious construction program, evidenced by a ratio of projected to total capacity close to 1.0 (where total capacity is already 12,633 MW). Its motives for this program are not clear, given that its sales growth averaged only 1.6% per year from 1973 to 1980[27/]. Sulfur premiums recaptured only after four months, combined with construction expenses, could contribute to short term cash flow problems; on the other hand, North Carolina's short regulatory lag and policy of 100% of CWIP allowed in the rate base may be adequate to alleviate these problems.

Ohio has mainly coal utilities and allows only a biannual adjustment. Table 9 shows that it could experience relatively large additional fuel costs from more stringent requirements. Three of its utilities are quite strong financially. Of the rest, Ohio Edison and Toledo Edison have below average bond ratings and ROCE's, and Ohio Power has bonds rated in the speculative category, though its ROCE earned in 1980 is fairly high, and all three companies have some projected capacity. Although Ohio's policies relating to capital additions are relatively favorable and the use of forecast data may compensate for the infrequency of adjustment, they could experience difficulties in paying increasing sulfur premiums.

Pennsylvania allows only yearly adjustments and all of its utilities have a high percentage of fossil fuel capacity. Although three of its utilities are relatively strong, it has two in great difficulty and three others with below average bond ratings and ROCE's. It is difficult to see how these five utilities could manage to absorb increasing sulfur premiums over such a long period without worsening their already shaky positions. It might be added that all but one utility has some projected capacity, though only one has experienced significant sales growth from 1973 to 1980.

Rhode Island has quarterly adjustments and two all-oil utilities, one of which is having financial difficulties, evidenced by an extremely low ROCE; it could find quarterly adjustments too infrequent. The other is not extremely strong but has maintained an A bond rating and has no projected construction to exacerbate its short term cash flow situation.

South Carolina's one utility is fairly strong financially and should be able to bear sulfur premiums reasonably well over that state's six month lag period.

Vermont, which has no adjustment clause for large utilities and a long rate hearing process, has two utilities with substantial oil capacity, the larger of which appears quite strong. The other, Central Vermont, has less oil capacity (40%) but below average financial measures. Vermont does have adjustment clauses of varying lengths for "small" utilities, however, and it is probable that Central Vermont (with 84.0 MW of capacity) qualifies.

Virginia has only a biannual allowed adjustment. Its major utility has roughly 50% fossil fuel capacity, some projected capacity and below average financial measures. The infrequency of adjustment could cause problems for it if low sulfur premiums were large and increasing, but Tables 9 and 10 suggest that this state may not experience a large cost burden from premiums. In other respects, Virginia has very favorable regulatory policies toward utilities and these could offset the effect of the fuel adjustment policy if cost increases are not too rapid.

West Virginia likewise has only a biannual adjustment, and both its utilities are exclusively coal burning. They are also weak financially and could have trouble with sulfur premiums, given the infrequent adjustment.

Summary. In the sixteen states which allow rate adjustments monthly or as needed--Arkansas, Connecticut, Delaware, Florida, Illinois, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, New Hampshire, New Jersey, New York, and Wisconsin--utilities should have little difficulty financially from switching to low sulfur fuels. Even increasing premiums would be recovered with little lag.

Seven states allow quarterly or thrice yearly adjustments: Alabama, Georgia, Indiana, Maine, Massachusetts, North Carolina, and Rhode Island. Although this policy allows for a fairly rapid recovery of fuel costs, in each state but Alabama there are one or two utilities that might find even this lag difficult to cope with, either because they are currently in poor financial condition or because they are in a weak condition and are burdened in addition by large construction programs (possibly intended to lessen their use of oil).

Another four--Ohio, South Carolina, Virginia, and West Virginia--have biannual adjustments. South Carolina's and Virginia's utilities may be able to cope with only a semiannual recovery of increased fuel costs. West Virginia's utilities, however, are relatively weak financially and one has a significant construction program that would also be a drain on cash flow. For them, a biannual adjustment may be too infrequent to prevent sulfur premiums from further deteriorating their financial positions. While more than half of Ohio's utilities are in good shape, three have below average values of the financial measures and some construction as well. However, Ohio's use of a forecast test year may be a partial, if imperfect, substitute for more frequent adjustments. Both Virginia and Ohio have relatively favorable policies relating to capital investment which may partially offset their fuel policies.

Finally, three states have no clause or allow only a yearly adjustment: Missouri, Pennsylvania, and Vermont (though for large utilities only). Missouri's companies are of at least average financial strength, but all have high percentages of oil and coal capacity and construction programs. Such a lengthy cost recovery period could deteriorate their positions. While Pennsylvania has a few strong utilities, two are in great difficulty and three are quite weak. All five would find it difficult to absorb sulfur premiums that were increasing over such a long period, though Pennsylvania's use of a forecast test year may mitigate their problems to an unknown degree. The one utility in Vermont that would appear to have difficulty may be small enough to be allowed a more frequent adjustment.

In general, unexpected or increasing sulfur premiums that are not quickly recoverable may burden utilities with short term cash drains which may be difficult to cope with if they are in a weak condition already and/or have construction programs which are also causing large cash outflows. These problems may be alleviated to some degree by the use of forecast test years or by policies that allow for quicker recovery of capital expenditures. It is interesting that the major coal producing states, with the exception of Kentucky, have quarterly or longer adjustment periods. Another pattern is the use of quarterly or more frequent adjustments by the oil burning states of the Northeast. It is likely that the policies of the latter were adopted to cope with the oil price shocks of the past decade, while more moderate increases in coal prices have not rendered frequent adjustments as necessary in the former group of states.

III. The Financial Impact of Sulfur Removal at the Utility Level

In considering policies that require removal of sulfur at the utility level, we will confine our attention to the costs of flue gas desulfurization (FGD) equipment, ignoring such options as coal cleaning. We will first consider some representative costs for this equipment, discussing in a general way the variations in costs for older plants, new plants, and converted plants and the economic appropriateness of this technology for oil burning plants. We will then discuss the possible financial impacts of these costs on states and utilities and, finally, will compare the costs and financial implications of sulfur removal at the utility level with those of fuel switching.

Costs of FGD Equipment for Individual Plants

Oil burning plants. Our discussion of sulfur premiums for oil (Section II) found that sulfur may be more or less expensive to remove at the refinery than at the utility level, depending on the quality of the fuel input. Since much desulfurization equipment is already in place in refineries, we will assume that additional equipment at the utility level is not called for and will confine the following discussion to coal burning companies.

Cost for new plants. Table 13 presents some representative costs for wet FGD systems (the most commonly used type) for old and new plants of various sizes[28/]. The entire range of levelized costs in the table is from 9% to 28% of a 60 mills/kWh electric rate. The levelized cost of equipment for a utility installing it on more than one plant will of course be a weighted average of those for the different plant sizes. The table illustrates not only that there are economies of scale (at least up to 500 MW plants) for both capital and operating costs but also that costs are significantly higher when the equipment must be retrofit (here the

Table 13. Costs of Wet FGD Systems for Individual Plants

Plant Size	Capital Cost 1980 $/KW	O&M Cost 1980 mills/kwh	Construction Cost 1980 million $	Levelized Cost 1982 mills/kwh
Retrofits: 90% Removal				
500 MW	140	3.3	70.0	11.11
200 MW	172	4.1	34.4	13.70
100 MW	207	5.3	20.7	16.92
50% Removal				
500 MW	90	1.9	45.0	6.88
200 MW	109	2.6	21.8	8.68
100 MW	157	3.6	15.7	12.34
New Plants: 90% Removal				
500 MW	107.7	2.5	53.8	8.55
200 MW	132.3	3.2	26.5	10.54
100 MW	159.2	4.1	15.9	13.02
50% Removal				
500 MW	69.2	1.5	34.6	5.29
200 MW	83.8	2.0	20.4	6.68
100 MW	120.8	2.8	12.1	9.49

Source: Teknekron Research Institute, Electric Utility Emissions: Control Strategies and Costs, prepared for the U.S. Environmental Protection Agency, March 1981, p. 38.

assumption is that they are 30% greater). However, a factor that mitigates these higher costs to some extent is that retrofitted equipment is eligible for special tax depreciation treatment. In simplified form, the portion of the property's basis attributable to the first 15 years of its useful life (15/20 or 75% of the value of a facility with a 20 year life) may be depreciated over 5 years (at a straight line rate). The remainder of the basis is depreciated over its useful life (e.g., 20 years)[29/]. In contrast, pollution control equipment that is part of a new plant must be depreciated over the generating plant's useful life, which is 15 years for a coal plant under the Economic Recovery Tax Act of 1981. Although depreciation of the generating facility may be at a rate greater than the straight line rate, the special provision for retrofitted equipment is still more advantageous[30/]. It is not clear how much the 30% cost disadvantage is decreased by this special allowance. If the government wishes to require or encourage utilities to install FGD equipment on new plants it might consider extending this subsidy to such investments.

Costs for plants converted to coal use. Since the oil embargo of 1973-74, much consideration has been given to converting oil plants to coal, and some utilities, reportedly including Virginia Electric and Power Company, have made voluntary conversions since that time[31/]. The federal government slated a number of plants for conversion, though it has since exempted many on grounds of proven difficulty in meeting pollution requirements. State and federal governments at times have given variances to the normal pollution control requirements (e.g., for FGD equipment). Some studies have claimed, however, that coal conversions offer savings to many utilities and consumers even with pollution control equipment as part of the investment.

When FGD systems are made a part of a converted plant, it seems likely that their costs would be those for retrofitted systems; it also seems likely that they would be eligible for the special depreciation provisions noted above.

Financial Impacts of FGD Costs and States and Utilities

To give some idea of how states might be differentially affected by the cost burdens of pollution control equipment, Tables 14 and 15 present illustrative costs for retrofitting all old coal plants of those utilities included in the study to achieve a 90% reduction (Table 14) and a 50% reduction (Table 15) in SO_2 emissions. (Methods of calculation and sources are in Appendix 3.) The retrofitting of all plants was chosen for illustration as representing a stringent policy, and using all plants enables each state's share of coal power to be accounted for in a simple way. The 90% reduction case could represent a policy that requires all plants to meet New Source Performance Standards. The more moderate 50% reduction case is roughly comparable to the fuel switching case discussed in Section II.

Interpretation of table values. Some care must be taken in interpreting the values in the table. Columns (3) and (4), direct construction costs and operating costs, are simply the state's average costs of columns (1) and (2) multiplied by its coal capacity and coal generation respectively. They given some idea of the relative burdens of an indentical policy for all states. They are proportional to the absolute amounts (rather than the percentages) of states' coal capacity and generation. For example, Ohio and West Virginia both generate more than 95% of their power from coal, but Ohio's construction costs would be double and its operating costs 60% higher than West Virginia's, for Ohio's coal capacity is 21559 MW (82% of its total capacity) and West Virginia's is only 9281 (90% of its total capacity).

The levelized cost of column (5) is based only on the average state capital cost and operating cost of columns (1) and (2). It will be a close approximation to the cost of a particular coal utility in the state if there is only one utility in the state or only one that is predominantly coal burning (e.g., Alabama, Delaware,

Table 14. Representative Costs for Wet FGD Systems Retrofit to All Existing Coal Plants for 90% Reduction

State	(1) Capital Cost 1980 $/kW	(2) O&M Cost 1980 mills/kWh	(3) Direct Construction Cost million 1980 $	(4) Annual O&M Cost million 1980 $	(5) Levelized Cost 1982 mills/kWh	(6) State Average Cost 1982 mills/kWh
Alabama	140	3.30	761.9	149.3	11.11	7.48
Arkansas	0	0	0	0	0	0
Connecticut	0	0	0	0	0	0
Delaware	172	4.10	159.3	9.9	13.70	5.02
Florida	148	3.53	639.0	69.7	11.78	2.39
Georgia	140	3.30	1418.8	163.9	11.11	8.32
Illinois	142	3.35	2331.8	224.1	11.27	7.02
Indiana	146	3.44	2231.0	239.5	11.58	10.09
Iowa	180	4.37	708.4	77.6	14.43	8.04
Kentucky	147	3.47	731.2	187.0	11.66	10.97
Louisiana	0	0	0	0	0	0
Maine	0	0	0	0	0	0
Maryland	181	4.40	228.6	64.2	14.52	4.41
Massachusetts	207	5.30	22.8	9.5	16.92	.43
Michigan	142	3.35	1465.2	169.0	11.27	6.69
Minnesota	148	3.51	680.3	70.4	11.76	7.35
Mississippi	172	4.10	246.8	28.6	13.70	4.39
Missouri	146	3.46	1283.8	162.5	11.60	9.64
New Hampshire	207	5.3	95.0	14.5	16.92	6.81
New Jersey	160	3.89	394.6	25.0	12.83	2.40
New York	160	3.82	559.4	55.3	12.75	1.67
North Carolina	140	3.3	1675.7	199.5	11.11	7.60
Ohio	144	3.39	3097.7	364.2	11.42	9.96
Pennsylvania	145	3.44	2210.3	339.7	11.53	7.46
Rhode Island	0	0	0	0	0	0
South Carolina	140	3.30	252.6	64.4	11.11	5.28
Vermont	0	0	0	0	0	0
Virginia	140	3.30	515.6	44.2	11.11	3.90
West Virginia	140	3.30	1299.3	230.9	11.11	10.34
Wisconsin	158	3.78	911.1	94.3	12.60	7.91

Table 15. Representative Costs for Wet FGD Systems
Retrofit to All Existing Coal Plants
for 50% Reduction

State	(1) Capital Cost 1980 $/kW	(2) O&M Cost 1980 mills/kWh	(3) Direct Construction Cost million 1980 $	(4) Annual O&M Cost million 1980 $	(5) Levelized Cost 1982 mills/kWh	(6) State Average Cost 1982 mills/kWh
Alabama	90	1.90	489.8	86.0	6.88	4.61
Arkansas	0	0	0	0	0	0
Connecticut	0	0	0	0	0	0
Delaware	109	2.60	100.9	6.3	8.68	3.18
Florida	98	2.10	424.2	41.4	7.53	1.52
Georgia	90	1.90	912.0	94.4	6.88	5.15
Illinois	91	1.95	1492.9	130.5	6.99	4.35
Indiana	93	2.03	1423.3	141.4	7.18	6.24
Iowa	120	2.82	472.8	50.1	9.51	6.56
Kentucky	94	2.05	467.4	110.5	7.26	6.83
Louisiana	0	0	0	0	0	0
Maine	0	0	0	0	0	0
Maryland	121	2.85	153.1	41.6	9.6	2.90
Massachusetts	157	3.60	17.3	6.5	12.34	.30
Michigan	91	1.94	939.4	97.9	6.97	4.12
Minnesota	95	2.08	435.9	41.7	7.35	4.60
Mississippi	109	2.60	156.4	18.1	8.68	2.78
Missouri	95	2.03	838.0	95.3	7.29	6.02
New Hampshire	157	3.60	72.0	9.8	12.34	4.94
New Jersey	110	2.40	271.7	15.4	8.50	1.58
New York	104	2.01	364.3	29.1	7.73	1.01
North Carolina	90	1.90	1077.2	114.9	6.88	4.67
Ohio	92	1.98	1983.4	211.5	7.07	6.15
Pennsylvania	93	2.02	1413.9	199.5	7.17	4.60
Rhode Island	0	0	0	0	0	0
South Carolina	90	1.90	162.4	37.1	6.88	3.27
Vermont	0	0	0	0	0	0
Virginia	90	1.90	331.5	25.4	6.88	2.41
West Virginia	90	1.90	835.3	132.9	6.88	6.39
Wisconsin	103	2.32	592.9	57.9	8.05	5.05

Maryland, Massachusetts, Mississippi, New York, New Hampshire, South Carolina, Virginia). It will also closely approximate the costs of each utility if they all have roughly the same percentages of coal capacity and generation as is the case in Indiana (except for one utility), Kentucky, North Carolina, Ohio, and Wisconsin (except for one utility). These levelized costs merely reflect the assumed mix of coal plant sizes in a state and not the state's amount or proportion of coal use.

The values in column (6) are the levelized costs of column (5) weighted by each state's percentages of coal capacity and generation. They are thus intended to account for the higher burden of heavy coal use rather than to represent actual cost increases to an "average" customer in a state. When a state has only one utility in the study, however (as do Alabama, Delaware, New Hampshire, South Carolina and Virginia) or if the percentage of coal use is similar for all utilities in a state (as in Kentucky, Ohio, North Carolina, and West Virginia), these numbers will approximate the cost increases to typical consumers in the state. In a state like Maryland, with one coal utility and one non-coal utility, for example, the customers of the former would experience a cost increase close to the column (5) value while customers of the latter would have no cost increase.

In sum, the point of column (6) is to illustrate the much smaller statewide burden for states with low average coal use, but it obscures the variation in cost increases that customers of different utilities may incur. In states with low coal use and no wide variation in coal use among their utilities, like Delaware, Massachusetts, New Jersey, South Carolina, and Virginia, the cost increases suggested by these computations appear to be rather small percentages of a typical electric rate (0.5-5.0% of 60 mills/kwh for a 50% reduction and 0.7-9.0% for a 90% reduction) and would be fairly evenly spread over utilities and consumers in the state. They would thus seem not unduly burdensome, at least for the 50% reduction case.

The interaction of FGD costs, utility finance and regulation. However, a thorough consideration of how states and utilities might bear these costs must be more complex and take account of companies' current financial condition and construction commitments and of the regulatory climate, which determines the readiness with which capital investment costs would be recovered.

As an example of this complexity we might reexamine the state of Virginia, which appeared from Tables 14 and 15 to be among those least affected by the requirement to install FGD equipment. Its one utility would face construction expenditures of $110 or $170 million in each of three years (depending on the policy case) on top of its 1981 and projected 1982 and 1983 expenditures of $676, $789 and $928 million. These would be significant additions to a construction program that is already so burdensome that the company has recently been selling portions of its power plants[32/]. The utility's financial measures (Table 2) reflect this burden. While the state has extremely favorable policies toward capital investment--100% CWIP allowed in the rate base, a 15% allowed ROCE, normalization of tax savings, and a mere 5 month lag for rate decisions--they can perhaps have only a gradual effect in helping the company to regain its financial strength so long as its construction commitments continue.

In general, while favorable regulatory policies toward capital investment are important determinants of utilities' abilities to finance pollution control equipment, at their best they do not allow the speed of cost recovery of a monthly or quarterly fuel adjustment clause. For example, even if 100% of CWIP is allowed in the rate base, it is typically put in the rate base only as a result of normal rate setting hearings, with the corresponding regulatory lag, which at minimum is 5 months. This is not to argue in favor of instituting procedures that would allow such quick recovery of capital costs (though some such system was instituted in New Mexico). (Whatever arguments have been adduced against automatic fuel adjustment clauses on grounds that they eliminate incentives to minimize costs have even greater force for capital cost recovery when one considers the skyrocketing construction costs of recent years and assumes that these, more than fuel costs, might be subject to control by utility management.) It is merely to point out that there is a certain gap between the most favorable fuel adjustment policies and the most favorable policies toward capital investment that should have obvious implications for the choice of air pollution control strategies.

A general comparison of state sensitivity to FGD costs. One approach to comparing states would be a detailed utility-by-utility analysis such as we have just done for Virginia. However, the larger number of utilities in most states and the number of financial and other factors that must be considered make this approach impractical for a report of this scope.

In Table 16, we group states by coal use (greater or less than 50% of generation) at different average SO_2 emission rates. Within each group, states which have more than one utility in some financial difficulty are indicated with an asterisk (*). In making these judgments, we have referred to the financial and other data in Table 2, looking at the alternate as well as the standard ROCE measures and in some cases considering whether state regulatory policies relevant to capital investment are strongly positive or negative.

Since stricter standards under consideration for coal emissions are around 1.5 lb $SO_2/\overline{M}Btu$, the states with 1980 emission rates of not more than 1.6 lb $SO_2/\overline{M}Btu$ should not be affected at all unless they are made subject to a percentage reduction or a technology requirement. Only four states, however, fall into this insensitive category. It is interesting that most of the heavy coal using states with high emissions rates have fairly healthy utilities. It must be kept in mind, however, that this analysis is quite relative. Most states in the survey have some ongoing construction programs, to which these

Table 16. Sensitivity of Coal Burning States to FGD Equipment or Fuel Switching Costs

Coal Use in 1980:	50% or greater	less than 50%
(a) 1980 emission rates $\geq$ 3.0 lb. SO_2/MBtu		
	Illinois	Florida
	Indiana	New Hampshire*
	Kentucky	
	Missouri@	
	Ohio*@	
	Wisconsin	
(b) 1980 emission rates $\geq$ 2.0 lb. SO_2/MBtu		
	Alabama*	Delaware
	Georgia*	Maryland*
	Iowa	Mississippi
	Michigan*	New Jersey
	Pennsylvania*@	New York*
	West Virginia*@	South Carolina@
(c) 1980 emission rates $\leq$ 1.6 lb. SO_2/MBtu		
	Minnesota	Massachusetts
	North Carolina*@	Virginia*@

@ States which allow fuel cost adjustments three times a year or less frequently.

* States with a number of coal burning utilities that are weak financially.

FGD equipment costs would be added. Further, the electric utility industry, as a whole, has been in declining financial health and has a limited ability to bear new debt and to attract new capital (see Section I). Many utilities in states with heavy coal use but somewhat lower emissions rates could definitely have trouble if FGD equipment were required, given their current financial condition. It is also important to keep in mind that certain utilities in low coal use states may be heavy coal users. Maryland, New Hampshire, and New York are states with single utilities that are financially weak and heavy coal users.

Comparing Table 16 with the data in Tables 2 and 4 suggests that different judgments might have been made in identifying states with financially weak utilities. It is therefore worth mentioning possible borderline cases and commenting more specifically on the reasoning underlying their placement. In the cases of Alabama and Georgia, the bond ratings were decisive, for the companies' ROCE's improve with the alternate measure, and regulatory policies are favorable; however, the bond ratings represent a rather comprehensive judgment in themselves and further, the availability of lower cost debt financing would be critical in undertaking additional construction. North Carolina's position is determined by the size and dominance of Duke Power in the state, a utility which has already been weakened by a huge construction program. Among the states with less coal use, bond ratings were again decisive for Maryland, particularly given the company's apparent construction plans, even though the state's regulatory policies are favorable.

Comparison of Fuel Switching and Plant-Level Sulfur Removal

To compare the cost impact on states of these two types of air pollution control strategies, we might compare the average state costs in 1982 mills/kwh in Table 9 (for a 50% reduction in average sulfur content of fuels) with the state average costs (column (6)) of Table 15 (for a 50% reduction in SO_2 emissions by the use of

FGD equipment).

It is clear that fuel switching imposes a smaller cost burden on utilities and consumers: for our assumed \$3.60/ton premium in all states or for the Argonne value of \$7.00/ton in all states but one. Overall, for the 30 state region, fuel switching would add approximately \$2.938 billion in annual costs, compared with \$5.114 billion for FGD systems (values in 1982\$, based on 1980 generation). This result is perhaps not surprising since it accords with many engineering estimates of least-cost strategies for individual utilities. With a 50% premium, the FGD system might have the advantage from a consumer point of view. Utilities' positions might be uncertain: they would experience greater lags in recovering the construction costs than in passing on fuel premiums, but on the other hand, the FGD investments would eventually enlarge the basis upon which their return to equity is calculated.

Table 16 and Table 17 (which segregates states by percentage of oil use for different ranges of emission rates) give another perspective for comparing the two policies. In each table, states with unfavorable fuel adjustment policies are marked with an '@'. The other states allow quarterly or more frequent adjustments and few, if any, of their utilities would be burdened by sulfur premium costs. It is first worth noting that more than half of the states appear to meet a strict standard with respect to oil emissions of 1.2 lb. $SO_2/\overline{M}Btu$, compared with only a few states for a strict coal emissions standard. Only two states with emission rates greater than 1.2 lb. $SO_2/\overline{M}Btu$ (from oil) have unfavorable fuel adjustment clauses, indicating the financial ease with which states could switch to lower sulfur oils. Table 16 for coal using states shows that five states with emission rates greater than 1.6 lb. $SO_2/\overline{M}Btu$ have unfavorable fuel adjustment clauses and three of these have financially troubled utilities as well, but the much greater number of states with weak utilities, heavy coal use and high emissions

Table 17. Sensitivity of Oil Burning States to Fuel Switching

Oil Use in 1980:	50% or greater	less than 50%
(a) 1980 emission rates $\geq$ 2.0 lb. SO_2/MBtu		Mississippi New Hampshire South Carolina@
(b) 1980 emission rates > 1.2 lb. SO_2/MBtu	Massachusetts	Arkansas Florida Georgia Maine Maryland Minnesota New York Virginia@
(c) 1980 emission rates $\leq$ 1.2 lb. SO_2/MBtu	Connecticut Delaware Rhode Island	Alabama Illinois Indiana Iowa Kentucky Louisiana Michigan Missouri@ New Jersey North Carolina@ Ohio@ Pennsylvania@ Vermont@ West Virginia@ Wisconsin

@ States which allow fuel cost adjustments three times a year or less frequently.

rates again confirms that fuel switching is, overall, the more desirable strategy.

IV. Summary and Conclusions

Finance

The electric utility industry has experienced difficult financial circumstances since the early 1970's as a result of rising fuel and construction expenses and slower than expected demand growth. By 1976-77 many had recovered to some extent and most had market-to-book ratios near 1.0, but from this time to 1980, the market-to-book and interest coverage ratios fell, many bonds were downrated, and earned returns on common equity (ROCE's) were constant or fell somewhat. This erosion was perhaps largely due to the rising interest rates of this period: higher interest costs worsened utilities' positions in the bond markets and in the equity markets as well, since utility stocks trade in competition with fixed income securities. The low earned ROCE's made it difficult to attract buyers for new equity issues, the market-to-book ratios of less than unity caused new equity issues to dilute current shareholders' positions, and the bond downratings made it necessary to pay higher interest rates in order to attract debt investors. (Table 2 shows the status of individual utilities with respect to a range of financial and physical variables.)

Many state regulatory commissions have responded with higher allowed ROCE's, and these are reflected in utilities' higher average earned ROCE's as of early 1982. Today's lower inflation rates, however, may make commissions less generous in the near future. There is considerable uncertainty concerning interest rates, allowed equity returns, and inflation over the short run period of the next five years.

Within this general picture of the industry, 13 states of the 30 considered in this study have a majority of utilities with Aa or A bond ratings, while 7 of these states also have a majority of utilities with ROCE's of 11.1% or greater (the 1980 average). (See columns (1) and (2) of Table 3.) A few utilities seem to be in severe difficulty, with bond ratings below Baa and ROCE's well below the 11.1% average. They are scattered geographically, but some states have larger numbers of financially weak utilities than others. (See, for example, column (3), Table 3.)

Regulation

State regulatory commissions affect utilities' financial positions when they set electric rates, and they do so through a variety of policies that determine the size and timing of companies' earnings. Table 4 shows states' positions on a variety of policies. First, they set the allowed ROCE, which determines the size of the return to capital investment. To the extent that commissions allow construction work in progress (CWIP) to be included in the rate base, utilities may earn a return on a project before it is completed. (Traditionally, utilities may recover costs only on facilities that are "used and useful.") If the state allows utilities to "normalize" their substantial tax savings from accelerated depreciation and the investment credit (and most do) then the companies may retain the use of these funds temporarily before passing the savings through to rate payers. By using forecasted rather than historical data during the rate making process, commissions may arrive at more accurate allowances for operating costs (which can rise significantly just during the rate hearing period in times of inflation). Finally, the length of the rate setting process itself has a significant financial effect in inflationary periods. This problem prompted the introduction of fuel cost adjustment clauses, most of which allow for a more frequent and automatic recovery of these costs than would be provided in the normal rate setting process.

Of these policies, the last is most critical for utilities switching to lower sulfur fuel. The former policies, in combination, affect companies' abilities to bear the capital and operating costs of sulfur removal equipment. Here, the policies toward tax savings are favorable in nearly all states, so the most important policies are the size of the ROCE and the question of allowing an early recovery of construction costs (CWIP in the rate base). It is clear that these two policies may substitute for one another. In fact, few states have highly favorable policies across the board; many are generous in one policy area but rather stringent in others. None of a sample of states questioned further admitted favoritism toward pollution control investments over other types of projects when deciding whether to allow CWIP in the rate base.

While higher ROCE's and allowing CWIP in the rate base may help utilities bear the costs of FGD equipment, these kinds of state policies may not be sufficient to help companies that are currently burdened with other construction programs and declining sales. Our sample, in fact, does not show a clear correlation between favorability of these regulatory policies and financial health of utilities, and these construction and planning factors may help account for this discrepancy. Utilities with declining sales growth over the period 1973 to 1980 which nevertheless have construction plans for new generating plants tend to have below average values for the financial measures we have considered. In contrast, utilities whose sales growth exceeded 4% per year during that period are more likely to have at least average values for these measures, and several have maintained above average values in spite of substantial construction programs. State regulatory commissions have recently begun to confront the problems of utilities in the first category, but the best policy routes are far from clear. In some states in the South, utilities have been required (and able) to sell unneeded generating facilities. In other parts of the country with no ready buyers for extra plants, facilities have been cancelled, raising difficult questions of responsibility for the costs already incurred.

Fuel Switching

One general option for meeting air pollution control standards by utilities is the use of fuel with a low sulfur content. This will impose additional costs on utilities and consumers to the extent that these fuels command a price premium. Our general consideration of this question and our specific attempts to identify these premiums suggest that they are currently relatively low and should not be expected to be large or growing unless there are monopolistic characteristics in the markets for these fuels. Our models suggested one-percent sulfur premiums for coal of 5.0% - 7.5% of price, much smaller than those from other studies; premiums for oil from our study were a higher percentage of price, nearly 15%. The only empirical data supporting the possibility of monopolistic pricing behavior in either market are (1) the large gap between even the higher estimate of the cost of sulfur removal and the amount of the premium for oil and (2) the regional concentration levels of the oil refining industry.

For illustration, we examined a policy requiring the average sulfur content of fuel used in each state to be reduced by 50% (Tables 9 and 10). One result, of course, is that states with both high fossil fuel use and high current sulfur levels will experience the greatest cost burden from such a uniform policy. (Tables 16 and 17 identify these states with respect to coal use and oil use.) Such states might be the most burdened by more selective policies as well, since their high sulfur level may target them for more stringent policies than other states. In fact, a number of these states are in the industrial midwestern area being identified as responsible for much of the acid rain problem.

As noted above, fuel adjustment clauses are critical in determining utilities' abilities to bear additional fuel costs. States with quarterly or monthly allowed adjustments should in general have no trouble with sulfur premiums, although one or two utilities subject to quarterly adjustments may be sufficiently weak to experience some difficulty. Fuel adjustments that are less frequent than quarterly could cause problems for more utilities, and a number of large coal using states fall into this category, as Table 16 indicates. States that are heavy oil users tend to allow frequent adjustments.

Utility Sulfur Removal

Another means of meeting air pollution control standards is by the use of flue gas desulfurization (FGD) equipment at the utility generating plants. Our analysis does not provide a definitive answer to the problem of comparative costs of oil refinery desulfurization and utility flue gas desulfurization. However, information provided by utilities indicates that our cost estimates for FGD equipment are certainly not too high, so that refinery desulfurization may have a greater cost advantage than our analysis suggests[33/]. Also, declining oil use by utilities and the existence of desulfurization equipment at refineries suggests that utility level removal may not be necessary or appropriate for oil.

The costs of FGD equipment are higher for retrofitted plants than for new plants, though this difference is lessened somewhat by the special tax treatment allowed only for retrofitted equipment.

Looking now at hypothetical retrofitting policies for all states, cost increases to consumers, at least for a 50% reduction in SO_2 emissions, do not appear to be extremely large: for utilities with low coal use they range from 0.5%-5.0% of a 60 mills/kwh electric rate and for heavy users of coal, from 10.0%-11.0% (Table 15). Since the average electric rate represented by 60 mills/kwh is far below the marginal cost of new generating facilities, these amounts represent an even smaller percentage of the per-kwh costs of utilities' other current construction programs. Yet given large construction programs underway, the extremely high cost of capital, and the lag in recovering construction costs, many utilities could be extremely burdened by even these modest requirements to install FGD equipment.

State regulatory policies could ease the burden somewhat. They could grant higher rates of return, but this policy would favor all capital investment, not just pollution control equipment. States that do not allow 100% of CWIP in the rate base already could adopt such a policy specifically for pollution control investments. In states where overconstruction of generating facilities is occurring, commissions could be more forthright in cancelling unneeded plants, although writing off these expenses may be costly in the short run. None of the policies applicable to the recovery of capital costs is as expeditious as an automatic fuel adjustment clause; they involve a lag at least equal to the length of the rate setting process.

Cost Effects on States

To identify the states most affected by the costs of burning lower sulfur fuel, we might select those for whom a 50% required reduction in fuel sulfur content would result in average state costs of greater than 1.5 mills/kwh in 1982 dollars (see Tables 9 and 10). For oil, these states are Delaware, Florida, Massachusetts, Mississippi, New Hampshire, New York, and Rhode Island. Massachusetts incurs the greatest average cost, at 4.7 mills/kwh; Delaware and Mississippi, the least in the group, at less than 2.0 mills/kwh. All of these states allow quarterly or more frequent fuel price adjustments; Massachusetts and Rhode Island have some utilities that could be burdened by their quarterly adjustment policies. For coal, the states with average costs of 1.5 mills/kwh or greater are Alabama, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, West Virginia, and Wisconsin. Kentucky's cost is the highest (5.8 mills/kwh) and Pennsylvania's is the lowest in this group (1.6 mills/kwh). Missouri, Ohio, Pennsylvania, and West Virginia allow only biannual or annual rate adjustments for increased fuel costs, and the last three states have a number of financially weak utilities (see Tables 2 and 16).

We have considered policies requiring additional FGD equipment only for coal burning utilities. Here the most affected states might be selected by identifying those with average state costs of more than 5.0 mills/kwh for a 50% reduction requirement (see Table 15). They are Georgia, Indiana, Iowa, Kentucky, Missouri, Ohio, West Virginia, and Wisconsin. Costs are greatest for Kentucky (6.8 mills/kwh) and least for Wisconsin (5.1 mills/kwh). Georgia, Ohio and West Virginia each have some utilities in financial difficulty.

Six of the eight most affected coal states are the same for both types of control strategy. Iowa's absence from the group affected by fuel switching is due to its current use of lower sulfur coal (see Table 9). The other differences may result from weighting costs for fuel switching by percentage of coal generation only but weighting those for FGD equipment by both coal generation and coal capacity. Alabama and Pennsylvania have significantly higher proportions of coal generation than coal capacity; whereas Georgia's percentage of coal generation is quite close to its percentage of coal capacity.

The cost estimates of Tables 9 and 15 indicate that for all states--and even with a much higher sulfur premium for coal--fuel switching is the less expensive option for meeting a uniform percentage reduction requirement. Some utilities have estimated costs of FGD systems that are higher than what we have assumed, tending to strengthen this conclusion[34/].

Tables 16 and 17 offer a more general ordering of states with respect to their oil and coal use, emissions rates, and vulnerability to increased pollution control costs. Asterisks (*) identify the states with coal using utilities that would be most likely to experience financial difficulties if required to make large capital investments in FGD equipment. The '@' symbol identifies states with allowed fuel adjustments that are less frequent than quarterly. Their utilities could have difficulty recovering the costs of sulfur premiums if they switched to lower sulfur fuels.

The Tables reveal that most states currently meet a stringent (about 1.2 lb. $SO_2/\overline{M}Btu$) standard for oil use, while only a few are close to meeting a similar (1.5 lb. $SO_2/\overline{M}Btu$) standard for coal use. Further, only two states' utilities would be likely to have great financial difficulty switching to lower sulfur oil (Table 17). A larger number of states with heavy coal use and high emissions rates have unfavorable fuel adjustment policies (Table 16), but considering the much larger number of asterisked states--where investment in FGD equipment would pose a particular burden for utilities--fuel switching again appears to be the most desirable overall approach to pollution control.

Policy Implications

One unresolved problem that emerges from this analysis is the relative cost of using FGD equipment at oil burning utility plants compared to the cost of processes that remove the sulfur from the fuel at the refinery. If the latter process is less costly, then regulations and legislation should permit this approach to sulfur removal.

A second suggestion is that FGD equipment required for new plants be allowed to receive the depreciation tax benefit now enjoyed only by retrofitted equipment, especially since requiring this equipment appears to impose an additional cost burden on utilities in cases where the same desired air quality could be met with low sulfur fuel alone.

Third, since the government has rightly acknowledged the value to the nation of converting plants from oil to coal, it should consider allowing such converted plants to meet air quality standards with low sulfur fuels, wherever this is possible.

In general, the government should move toward policies which allow utilities greater flexibility in selecting the method of meeting fixed air standards. Our illustrations of fuel switching and FGD cost burdens are in accord with the conclusions of other studies which show that fuel switching is often the more economical option. Such flexibility is also desirable because fuel costs may be recovered more readily than construction costs by most utilities: as noted above, state-level policy options for easing the burden of increased capital costs are more numerous but more limited than those for recovering fuel cost increases.

In advocating greater use of the fuel switching option, we must acknowledge that it poses certain problems of its own: consumers will bear the brunt of whatever sulfur premiums are charged. We have argued that supplies of low sulfur fuels and costs of refinery level sulfur removal are such that in a relatively competitive market, sulfur premiums, if they exist at all, should be short term and low. The presence of monopolistic elements in markets for low sulfur coal or oil, however, could cause premiums to be larger and more permanent. Though we are aware of no evidence of such monopolistic pricing behavior in coal markets and have only suggestions that it may exist in the oil refining industry, the institution of automatic cost pass-throughs (i.e., the current fuel adjustment provisions) in the electric utility industry could allow monopoly rents to be more easily extracted by fuel suppliers. Thus, while superficial evidence of monopolistic elements is weak, the consequences of their existence could be severe, so that Congress might consider a separate study of the nature of these markets. As protection against this possibility, if greater reliance is to be placed on fuel switching, regular review procedures of fuel adjustment clauses should be strictly enforced to give utilities sufficient incentives to bargain for low cost fuels and thus to help enforce competitive behavior among their suppliers.

FOOTNOTES

1. Table 1 also notes utilities in the ARMS region which have been excluded from the study because of size or because they have neither oil nor coal capacity.

2. J.B. Cohen, et al., Investment Analysis and Portfolio Management (Homewood, Ill.; Richard D. Irwin, Inc., 1977), p. 385. Thus, on occasion we will consider it legitimate to refer to aggregate data from other sources.

3. Standard and Poor Industry Surveys, Utilities-Electric, Basic Analysis, July 2, 1981, p. U23.

4. Standard and Poor Industry Surveys, Utilities-Electric, Current Analysis, May 7, 1981, p. U5.

5. Cohen et al., p. 306f.

6. Standard and Poor Industry Surveys, Utilities-Electric, Current Analysis, May 7, 1981, p. U5.

7. Survey of Current Business, U.S. Department of Commerce, June 1981.

8. Standard and Poor Industry Surveys, Utilities-Electric, Current Analysis, January 21, 1982, p. U6.

9. Standard and Poor Industry Surveys, Utilities-Electric, Current Analysis, May 7, 1981, p. U4.

10. This information was collected by Sally Hindman at Cornell University who sent out questionnaires in April 1981 and followed up with letters and phone calls until virtually 100% response was achieved by the end of 1981. The questionnaire appears in Appendix 1 of this study and the complete results will be available soon in monograph form.

11. Standard and Poor Industry Surveys, Utilities-Electric, Current Analyses, May 7, 1981, p. U3 and January 21, 1982, p. U5.

12. Ibid.

13. Standard and Poor Industry Surveys, Utilities-Electric, Current Analysis, May 7, 1981, p. U3.

14. Massachusetts and Rhode Island might also be included in this group, since they have ROCE's greater than 14.0%. Note that this includes nearly all of New England.

15. The Price and Availability of Low Sulfur Coal in Eastern Markets, Argonne National Laboratory, July 1977, p. 18.

16. Coal Data Book, February 1980, The President's Commission on Coal, p. 112.

17. Michael Le Blanc, A Transportation Model for the U.S. Coal Industry, M.S. Thesis, Cornell University, July 1976, p. 94.

18. The capital cost is from "Electric Utility Emissions: Control Strategies and Costs," Teknekron Research Institute (TRI), Energy and Environmental Analysis Division, prepared for the U.S. Environmental Protection Agency, March 1981, p. 38. The calculation assumes 9% yearly inflation, the .17 capital recovery factor, and consumption of 3.7 million barrels of oil per year: $(1.09)^2(140)(.17)(400{,}000)/(3.7)(140{,}000)(42) = \$.5199$.

18a. Technology Assessment Report for Industrial Boiler Applications: Oil Cleaning U.S. Environmental Protection Agency, 1978. The following cost discussion is based entirely on this report.

19. Another direction for further work would be to control better for regional differences. One possible approach would be to treat Texas, Oklahoma and Louisiana separately, but because there were no observations for Oklahoma, the data were insufficient to attempt this modification.

20. Duane Chapman, Energy Resources and Energy Corporations, (draft), May 1982, Chapter 6, p. 18.

21. And less than 1.2 lb in New York City. From In Pursuit of Clean Air ..., op. cit., Vol. 2.

22. Ibid.

23. Ibid.

24. Standard and Poor Stock Reports, New York Stock Exchange, April 1982.

25. Cost and Quality of Fuels for Electric Utility Plants, 1980 Annual, U.S. Department of Energy, Table 57, p. 148.

26. Missouri's Supreme Court declared its fuel adjustment clauses illegal (Standard and Poor Stock Reports, New York Stock Exchange, April 1982).

27. In fact it has delayed one plant and is selling interests in another that is under construction (Ibid.), reducing its program somewhat.

28. See Appendix C (discussion of column (5)) for the calculation of levelized cost. Construction cost here is simply capital cost times 500, 200, and 100.

29. 1980 Federal Tax Course, Commerce Clearing House, paragraph 1327, p. 1351.

30. These tax differences are not reflected in the levelized cost calculations used in this table.

31. See, for example, "Converting Power Plants to Coal," Power Engineering, December 1980, pp. 54-62.

32. Construction costs and plant sale information is from Standard and Poor Stock Reports, New York Stock Exchange, April 1982.

33. Questionnaire and responses from selected utilities surveyed by the U.S. Senate Energy Committee and provided to us by the U.S. Congress Office of Technology Assessment, August 4, 1982.

34. Ibid.

Appendix 1.

State Regulatory Policy Questionnaire

I. Rate Base

A. What items may be included in the rate base (RB) other than direct investment and AFUDC? 100% response

B. Are pollution control and conservation expenditures included in the RB? 100% response

1. Please distinguish between customer related and company conservation expenditures. 90% response

2. Has your state set policy for dealing with company conservation expenditures? 100% response

C. What percentage, if any, of CWIP is allowed in the RB before the facility is operating? 100% response

D. For book purposes (not tax): 1) What type of depreciation (i.e. SL, DDB, SYD) is used to depreciate various assets in the RB? 2) What asset lives are used to depreciate these assets? 100% response
a. nuclear plants 100% response
b. coal plants 100% response
c. oil and gas units (Please distinguish between asset lives for steam turbine and oil and gas "peaking units.") 94% response
d. hydro 100% response
e. transmission and distribution equipment 94% response
f. other significant parts of the RB 90% response

E. Is the RB adjusted for inflation? If yes, how is the adjustment made? 100% response

F. Is the AFUDC rate calculated by the FERC method? If not, specifically how is it calculated? 100% response

G. When is AFUDC allowed in the RB? Upon project completion? 100% response

H. Can AFUDC be earned on accumulated AFUDC which is not in the RB? (We're referring to compounded versus simple accumulation.) 100% response

II. Rates of Return

What rates of return are allowed on: A) common equity; B) the rate base? Please list most recent average rates of return or ranges. 100% response

1. How are these numbers determined? 100% response

2. How often are they revised? 98% response

III. Tax Treatment

A. Investment Tax Credit (ITC)

1. What ITC rate is used by most utilities in the state? (i.e., 10%, 11%, or 11-1/2%.) 94% response

2. What percentage of the ITC is normalized, flowed through? If some utilities flow through the ITC and some normalize it, please distinguish the number using each method. 100% response

3. How many utilities in your state claim the additional 1-1/2% for employee stock ownership plans? 92% response

B. Accelerated Depreciation

1. Which method(s) of depreciation are permitted for tax purposes? 100% response

2. What percentage of tax deferrals from accelerated depreciation are normalized and what percentage are flowed through? If some utilities flow through the tax deferrals and some normalize them, please list the number using each method. part 1, 100% response; part 2, 60% response

a. Please distinguish between deferrals from acclerated depreciation and deferrals from the asset depreciation range different from an investment's actual expected life. 50% response

b. Please describe in detail your method of normalization, if different from that applied to the ITC. 100% response

C. State Taxation

1. What types of taxation (corporate income, gross receipts, sales, property, etc.) does the state levy on electric utilities? Please list types of taxation and tax rates. 100% response

2. If your state has a corporate income tax, how does it differ from the federal corporate income tax? 100% response

IV. Miscellaneous

A. Does your state have an automatic fuel price adjustment clause? If so, please describe it. 100% response

B. Are companies who operate nuclear power plants required to contribute to an account which will be used to decommission these plants? Please describe the required contributions. 100% response

1. Are the funds segregated? 100% response

2. What have contributions been to date? 30% response

C. How many months on an average does it take to make a decision on requested rate increases? 98% response

D. How are fuel procurement investments treated? By fuel procurement investment I mean direct investment in coal mines, natural gas fields, nuclear fuel facilities, etc. 92% response

E. What percentage of electric power in your state is produced by non-investor owned utilities? Do you regulate these utilities directly? 100% response

F. Are there any significant state financial regulations that I have not mentioned? 92% response

G. Has your state considered how it will treat the additional tax benefits resulting from the ACRS? 100% response

NOTE: Percentages represent response rates to questions.

Appendix 2.
Modelling the Effect of Sulfur Content on Coal and Fuel Oil Prices

Introduction

Three models were developed to analyze sulfur premiums for low sulfur coal and fuel oil by relating coal and oil costs to certain explanatory variables[1/]. Model 1 attempts to identify the existence of a sulfur premium for low sulfur coals by comparing data from all states. Model 2 is an extension of this analysis and separates out the large relationship between regional influences and coal price by looking at a sample of coal prices and exogenous variables from states producing coal in the Appalachian Region of the U.S. Model 3 presents results on sulfur premiums for industrial fuel oil by using the price of fuel oil and a set of explanatory variables in a model similar to the previous two.

The variables used in the models for coal sulfur premiums can be grouped into three categories. One group includes physical characteristics of the coal: Btu content, percentage of ash and sulfur, and overall variability of the coal. The data used in this analysis unfortunately could not capture this latter variable.

A second group includes the geological distribution of coal: in what regions coal is more abundant and whether the coal is accessible by strip mining or must be extracted by underground mining.

The third category of variables is a collection of economic factors which might influence coal prices, for example, whether coal is bought by contract purchases (made more than one year in advance) or is bought in the spot market. Another such variable which cannot be identified directly from the data is the existence of monopolistic practices which could influence prices of certain grades of fuel. These variables do not exhaust all the possible factors which explain coal price, but they are probably the most influential.

Model 1

Model 1 uses cross sectional data--112 observations from 42 states--to analyze the effects of sulfur content on coal price. The generalized least squares (GLS) estimator is used since the ordinary least squares assumption of constant variance of the residual term might not be met with cross section data.

Various functional forms were compared, including the semi-log and quadratic, but the linear form was selected over the others on grounds of simplicity and better statistical results.

The exogenous variables selected for analysis were sulfur content (SCON), underground purchases (UNDR), contract purchases (CONT), ash and Btu content (ASH and BTU), and four regional dummy variables (D1, D2, D3, and D4). The dependent variable for coal price (COST) was measured in ¢/MBtu. An intercept term, C, was used also.

Coal shipments for each state were classified by sulfur content. Six categories exist in the data and are arranged as follows:

Sulfur Category	Range (% S in coal)	Midpoint
1	< .5	.25
2	.5 < S < 1.0	.75
3	1.0 < S < 1.5	1.25
4	1.5 < S < 2.0	1.75
5	2.0 < S < 3.0	2.50
6	> 3.0	3.50

Underground purchases were identified by percentage of each state's average purchases which came from underground sources. The variable CONT was used in the same fashion. More than one data point for CONT or UNDR for a state could therefore be the same. Btu content was based on a state's average Btu content for coal shipments and was expressed in Btu/lb. Ash was expressed as the state's average percent ash content.

Regional effects were to be accounted for using four dummy variables. D1 included all states producing coal in the east; D2, the midwest coal producing states; D3, the western coal producing; and D4, all states not producing coal. Table 2.1 describes the grouping of states.

Thirty-eight states are included in the sample. Four shipping states with coal shipments of less than 800,000 tons are excluded to prevent the prices of very small shipments from overinfluencing the analysis. (800,000 tons is based on what one 300 MW coal-fired power plant would have used as fuel in one year.)

Table 2.1

Dummy Variable

	D1	D2	D3	D4
States	Pennsylvania	Michigan	Arizona	New Hampshire
	Ohio	Illinois	Colorado	New Jersey
	Maryland	Indiana	Montana	New York
	West Virginia	Arkansas	Utah	Wisconsin
	Kentucky	Louisiana	Wyoming	Florida
	Tennessee	Oklahoma	North Dakota	Georgia
	Mississippi	Texas	South Dakota	South Carolina
		Iowa		North Carolina
		Kansas		Alabama
		Missouri		Nevada
				Oregon
				Washington
				Nebraska
				Minnesota

Model 1 Results

Statistics from Model 1 are presented in Table 6. The signs of the coefficients are in accordance with a priori knowledge. Sulfur and ash content should vary inversely with coal price, indicating that as the quality of the coal goes up so does the price. The coefficients for BTU and UNDR are correct in sign as are those for the dummy variables.

The dummy variables A1, A2, and A3 are just transformations of the four regional dummy variables collapsed so that multicollinearity does not influence results from these variables. Therefore,

$$A1 = (D1 - D4)$$

$$A2 = (D2 - D4)$$

$$A3 = (D3 - D4)$$

The T-statistics are all significant except for the variable UNDR, which is still questionable. The decision to keep variables or omit them was determined by sequentially estimating each variable in the model. The final model omits the variable for contract purchases (CONT) because it did not add much to the R^2 and its T-ratio was insignificant (-.127). The magnitude of the coefficients indicate that the dummy variables are influential in the price of coal. UNDR and BTU have relatively little influence on price. The F-statistic from the model was estimated to be 11.369, which is significant.

In this final model the R^2 statistic equals .45. **In an attempt to improve its explanatory power, the model was re-estimated using** 9 dummy variables for each U.S. Bureau of Mines region. The results need not be duplicated, but the inclusion of many dummy variables eroded the degree of freedom and presented problems with collinearity.

The first result from Model 1 is that sulfur content indeed is important in determining coal price. From the Table, a one percent increase in sulfur in a coal results in a corresponding 7¢/$\overline{M}$Btu decrease in price.

The other major conclusion is that more analysis is needed. **The R^2 value indicates** that the model may be missing some important determinants of coal price. Regional variation is very critical in determining coal price so it was hypothesized that if it could be held constant, sulfur content or some other variable might become sufficiently strong to overshadow other explanatory factors.

Model 2

The second model relating sulfur content to coal price retains the linear functional form with an intercept term and uses the GLS estimator as in Model 1. This model attempts to hold regional variation constant while allowing the other variables relating to coal price to change. It does so by using just Appalachian coal producing states' shipments for a total of 39 observations. The states used are Pennsylvania, West Virginia, Maryland, Virginia, Kentucky, and Tennessee. Not every data point is used, but only those shipments from a state to an adjacent state. No intrastate shipments were used. In this way, the regional effects are masked to analyze the other factor effects.

The dependent variable, COST, remains the same but in this model is measured in \$/ton. The model in its final form uses sulfur content (SCON), underground purchases (UNDR), Btu content (BTU), ash content (ASH), and contract purchases (CONT). As before, each variable was sequentially estimated before putting it into the model.

Model 2 Results

The final model and associated statistics are presented in Table 7. The most noticeable change in the model is that the R^2 is .85, which is much higher than in the previous model. The F-statistic for the model is highly significant, at 34.689.

As for the final structure of the model, no variables have been omitted and only CONT is added to the model in order to make the model more comparable to Model 1.

As in Model 1, the signs of the coefficients are correct, and ASH and SCON signs are negative as presumed. Now SCON becomes a more influential variable in determining coal price than any of the other variables in the model, in terms of the size of the coefficient. UNDR is much less important. Even its T-statistic is insignificant, perhaps because regional variation has been minimized so that all the coals have more comparable shares of underground purchases than in Model 1. All the other explanatory variables are significant, even CONT. By regionalizing coal prices, the effects from contract purchases apparently are accounted for more effectively and those from underground sources are made even less important.

This model has much better explanatory power than Model 1. The variables for coal quality are more important than other variables, with sulfur content being the most influential. As a result of the analysis, a one percent increase in sulfur in coal would lead to a 3.6\$/ton change in coal price, much more than under Model 1.

Model 3

The results from Models 1 and 2 measured low sulfur coal premiums. Model 3 will be used to discern the premium effects of low sulfur fuel oil on oil prices. Again, the modelling will use the GLS estimation procedure and the linear functional form.

This model uses only three exogenous variables: heating value of oil in Btu/gallon, sulfur content, and regional dummy variables. The dependent variable is price of oil in ¢/$\overline{\text{M}}$Btu. Sulfur content is based on the midpoint of the sulfur content classes given in the Cost and Quality of Fuels. There were 47 observations, including more than 1 observation for some states.

Model 3 Results

This model presents some problems, mostly constrained by the data. The R^2 is 64 percent, and the F-statistic is significant (see Table 8), but the T-statistics for heating value (HV) and the dummy variable (D1) are not significant. The dummy variable took states east of the Mississippi River equal to 1 and all others equal to 0. Sulfur content (SCON) is very significant; the T-statistic equals -8.517. The magnitude of the SCON coefficient is large, indicating a high degree of influence on the dependent COST variable. The signs of the coefficients are all correct, suggesting a negative relationship of SCON with COST and direct relationships of HV and D1 with COST.

Summary and Conclusions

All three models do reveal significant relationships between sulfur content and price of coal and fuel oil. From Model 3, the relationship appeared much stronger, indicating that for a one percent decrease in sulfur content, price would rise 57¢/$\overline{\text{M}}$Btu. Model 1 had the slightest effect from sulfur on cost of coal.

Other factors came into the determination of coal price as well, many of which could be measured directly from the data. Outside influences unable to be detected from the data may exist, however, and more work is needed to explore what these other phantom variables are.

1/ Data for all models are from Cost and Quality of Fuels for Electric Utility Plants, 1980 Annual, U.S. Department of Energy.

Appendix 3.

Sources and Methodology for FGD Representative Cost Calculations (Tables 14 and 15)

Columns (1) and (2), capital cost and operating and maintenance cost, are derived from Teknekron Research Institute (TRI), Energy and Environmental Analysis Division, "Electric Utility Emissions: Control Strategies and Costs," prepared for the U.S. Environmental Protection Agency, March 1981, p. 38, as cited in Clifford V. Rossi, Economic Effects of Sulphur Oxide Control for New York State Electric and Gas Corporation, M.S. Thesis, Cornell University, draft July 1982. (Refer to Table 3.1 for details and assumptions.) To account in a simple way for the higher costs for smaller plants, utilities with more than 1500 MW coal capacity were assigned costs for 500 MW plants; utilities with between 500 and 1500 MW were assigned the costs for 200 MW plants and those with less than 500 MW were assigned the costs for 100 MW plants[1/]. The capital cost for each state is

$$\sum_i \frac{(\text{cost/kW for utility i})(\text{utility i's coal capacity})}{(\text{total coal capacity in the state})}$$

The states' average operating and maintenance costs are computed similarly.

Multiplying the capital cost by the megawatts of capacity in each state[2/] and the operating and maintenance costs by the kilowatt hours of electricity generated by coal in each state in 1980[3/] gives columns (3) and (4), the direct construction cost of this hypothetical policy and the annual operating and maintenance expense for this additional equipment.

Column (5) converts the values in columns (1) and (2) to an estimate of the levelized cost in 1982 mills per kilowatt hour, which equals an amortized yearly charge for the capital costs (including AFUDC) plus the operating and maintenance expenses of column (2). The levelized cost =

$$\frac{(K)(FCR)(1000)}{(8766)(CF)} + OM.$$

K is the capital cost in \$/kW to which AFUDC has been added, assuming construction expenses are spread evenly over a 3 year period and the AFUDC rate equals the weighted average cost of capital (r), which equals .138, given the following capital structure and returns:

debt	.48	.13
common	.40	.15
preferred	.12	.13[4/].

FCR is the fixed charge rate and equals

$$\frac{r(1 + r)^n}{(1 + r)^n - 1} + T + A$$

where n = the assumed operating life of 20 years, T = taxes and is assumed to be 3% of K, and A is administrative expense, assumed to be 1% of K. CF is the capacity factor and is assumed to be .65. Both K and OM are multiplied by $(1.09)^2$ to get 1982 dollars.

While the levelized cost in column (5) is essentially that faced by a coal burning utility or by the customer of a 100%-coal utility, the cost in column (6) would result from spreading the cost of retrofitting these coal plants over all the customers in a state. Thus, many customers would experience cost increases somewhere between column (5) values and zero, while some would have increases at one end or the other of the range. The costs in column (6) are derived by multiplying the capital cost component by the percent coal capacity in the state and the operating and maintenance component by the percent of coal generation, and summing these values. (See Table 12 for these percentages.)

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1. This is not intended to be totally realistic (e.g., a utility with 1000 MW of capacity may have other than 200 MW plants) but only to allow some weight for this factor. A plant-by-plant calculation would go beyond our intention to make these cost calculations merely representative.

2. From U.S. DoE, Inventory of Power Plants in the U.S., 1980.

3. From Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1980, Table 22, p. 31.

4. Thus, capital costs including AFUDC equal

$$\frac{K}{3}(1.138)^3 + \frac{K}{3}(1.138)^2 + \frac{K}{3}(1.138)$$

Table 3.1. Wet FGD Capital and Operating Costs

Plant Size	SO_2[c] Removal	Capital ($ per KW) 1980[a]	Capital ($ per KW) adjusted 1982[b]	O & M (mills/kwh) 1980[a]	O & M (mills/kwh) adjusted 1982[b]
500	90	140	166	3.3	3.9
	70	114	135	2.5	3.0
	50	90	107	1.9	2.3
200	90	172	204	4.1	4.9
	70	156	185	3.3	3.9
	50	109	126	2.6	3.1
100	90	207	246	5.3	6.3
	70	179	213	4.4	5.2
	50	157	187	3.6	4.3

[a]To get new plant estimates, divide capital and O & M costs by 1.3.

[b]Adjust by $(1.09)^2$, reflecting nominal 1982 dollars.

[c]Assumes 2.2 SO_2 input (lb/$\overline{M}$Btu).

Assumptions:

A 1.3 retrofit factor.
No sludge pond if FGD size is less than 150 MW (e.g., 200 MW, 50% SO_2 removal).
Sludge disposal cost (if no pond) at $15.00/dry ton (1979 $).
Electricity cost at 37 mills/kwh (1979 $).
No spare modules for retrofitted systems.
No spare ball mills for retrofitted systems.
No percent contingency on direct costs.
No contingency on indirect costs.
Pond indirect costs at 15 percent of direct costs.
Variable O & M costs include only limestone, utilities, and sludge disposal.
Operating labor at $12.50 per hour (1979 $).
Limestone cost at $7.00 per ton (1979 $).
Analysis labor at $17.00 per hour (1979 $).
Steam cost at $2.00 per thousand pounds ($2.66/$\overline{M}$Btu) (1979 $).
Water cost at $0.13 per thousand gallons (1979 $).

Source: Teknekron Research Institute, Electric Utility Emissions: Control Strategies and Costs, prepared for the U.S. Environmental Protection Agency, March 1981, pp. 38, 39.