

Appendix A: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR FUEL COMBUSTION SOURCES

This appendix describes the emission factors used, the sulfur emissions sources examined, and the control alternatives costed as part of the research presented in the text for steam-electric power plants and area sources.

A.1 Emission Factors

In the absence of controls, essentially all the sulfur contained in fossil fuels is emitted as sulfur oxides. The amount of sulfur emissions depends upon (1) the quantity of fuel consumed and (2) the quantity of sulfur per unit of the consumed fuel.

For both the steam-electric power plants and the area sources, the quantity of fuel consumed is based on projections of the demand for heat energy expressed in Btu. Projections of the national demand for electricity developed by the Edison Electric Institute* have been used to project the demand for Btu by steam-electric power plants. The 1970 Btu consumption by the area sources on a State-by-State basis have been continued to 1978 using projected population growth rates to project residential fuel consumption and projections of employment growth rates to derive projections of commercial and residential fuel consumption.† The estimated 1970 consumption of fuels by State and source are shown in table A.1.

The sulfur content of fuels is normally expressed as a percent by weight. The amount of sulfur emitted per ton of fuel is 20 lb for each 1 percent of sulfur content in the fuel. For example, a typical coal of 3.5 percent sulfur content releases 70 lb of sulfur per ton during combustion. Similarly, for residual oil weighing 7.88 lb per gal, 1 percent sulfur oil emits 0.0788 lb of sulfur per gal. Sulfur emissions per unit of heat contained vary with the heat content of the fuel. The heat content of coal varies significantly depending on the specific coal. For residual oil and gas, there is little variability. Data on the fuels and their heat contents are presented in the section on control alternatives.

*Edison Electric Institute. Fuels for the Electric Utility Industry, 1971-1985, New York, Edison Electric Institute, 1972.

†U.S. Department of Commerce, Survey of Current Business, Vol. 52, No. 4, April 1972, p. 22-48.

Table A.1.^a Area source fuel consumption by State, 1970

State	Residential		Commercial				Industrial					
	Distillate oil (thousand bbl)	Gas (million ft ³)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft ³)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft ³)		
Maine	8,547			1,072	1,461.6			643.2	2,703.9			
New Hampshire	6,279	3,400	15	693	659.4	970.9	135.4	415.8	1,219.9	681.8		
Vermont	4,293			591	200.7			354.6	371.3			
Massachusetts	46,243	53,400	57	7,014	19,011.3	14,471.7	293.3	4,208.4	35,170.9	7,789.9		
Rhode Island	6,640	7,400	Included with Me., N.H., Vt.		847	1,404.8	1,905.9	Included with Me., N.H., Vt.		508.2	2,598.9	2,159.5
Connecticut	16,399	19,800	1	3,601	2,901.8	4,892.4	251.1	2,160.6	5,368.3	5,477.9		
New York	76,637	225,300	80	18,106	36,451.8	58,269.8	5,659.6	10,863.6	67,435.8	39,746.4		
New Jersey	38,743	98,900	8	12,883	8,367.4	17,777.3	450.1	7,729.8	15,479.7	26,933.6		
Pennsylvania	37,327	200,600	600	6,160	8,265.5	46,331.5	7,711.9	3,696.0	15,291.2	119,294.0		
Delaware	2,992	5,100	70	307	315.9	1,338.8	1,168.9	184.2	584.4	4,188.5		
Maryland	11,346	57,400		1,428	3,134.8	16,410.4		856.8	5,799.4	14,324.1		
Dist. of Columbia	2,583		70	464	5,055.1		375.3	278.4	9,351.9			
Virginia	11,507	31,700	500	1,313	1,006.5	12,217.6	4,000.9	787.8	1,862.0	14,799.4		
West Virginia	295	38,300	250	32	342.2	9,680.9	4,936.1	19.2	633.1	31,913.7		
North Carolina	12,148	18,900	500	1,131	679.5	8,668.2	2,001.5	678.6	1,257.1	24,566.2		
South Carolina	3,961	12,400	300	442	154.9	6,108.8	1,300.0	265.2	286.6	27,281.1		
Georgia	1,936	59,800	160	169	1,150.5	19,469.0	526.9	101.4	2,128.4	50,037.8		
Florida	3,929	7,900		351	833.3	10,602.1		210.6	1,541.6	31,668.4		
Michigan	24,368	226,600	900	2,079	899.8	67,759.4	7,922.6	1,247.4	1,664.6	100,399.6		
Ohio	14,156	301,400	1,500	1,466	298.9	82,459.5	14,601.1	879.6	552.9	128,687.7		
Indiana	15,056	106,600	600	1,416	1,748.9	36,922.9	6,418.4	849.6	3,235.5	94,407.6		

Table A.1. Area source fuel consumption by State, 1970 (continued)

State	Residential		Commercial				Industrial			
	Distillate oil (thousand bbl)	Gas (million ft ³)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft ³)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft ³)
Illinois	19,601	295,200	2,800	2,550	8,873.1	97,085.4	7,741.3	1,530.0	16,415.2	125,555.9
Wisconsin	17,417	68,800	1,600	1,919	599.6	21,472.9	4,096.7	1,151.4	1,109.3	44,934.8
Minnesota	13,456	65,000	900	1,118	605.7	24,231.6	1,584.2	670.8	1,120.5	32,467.8
Iowa	6,340	62,000	200	467	158.6	27,537.7	1,694.9	280.2	293.4	31,735.9
Missouri	1,145	103,200	100	620	1,225.5	35,625.5	1,615.9	372.0	2,267.2	35,287.4
Kansas	530	64,100	} 60	44	262.9	24,664.1	} 227.4	26.4	486.4	54,919.6
Nebraska	1,866	37,500		158	79.3	18,216.1		94.8	146.7	17,606.1
South Dakota	2,572	8,800	} 200	146	9.2	4,779.0	} 473.2	87.6	17.0	2,194.2
North Dakota	2,617	5,200		220	42.1	3,667.1		132.0	77.9	981.8
Kentucky	1,950	57,000	500	182	70.8	17,352.7	2,199.6	109.2	130.9	22,973.7
Tennessee	1,679	30,900	600	148	9.2	19,994.8	2,229.5	88.8	17.0	41,021.8
Alabama	566	37,300	} 100	53	47.6	18,809.7	} 1,767.6	31.8	88.1	60,727.8
Mississippi	629	20,600		58	29.9	8,015.7		34.8	55.3	43,348.9
Arkansas	449	39,700	} 4	40	-	20,064.2	} 113.7	24.0	-	51,774.5
Louisiana	618	56,400		57	9.8	17,320.4		34.2	18.1	337,363.9
Oklahoma	523	51,200		35	100.7	19,195.0		21.0	186.3	40,691.0
Texas	2,470	150,100		157	337.9	48,797.6		94.2	625.1	599,958.5
Montana	970	14,600	} 250	37	111.6	7,546.7	} 161.4	22.2	206.5	11,170.9
Idaho	2,792	4,700		178	71.9	2,822.3		106.8	133.0	8,919.8
Wyoming	581	11,300	20	52	207.4	6,626.1	212.2	31.2	383.7	14,932.8
Colorado	1,170	55,100	300	53	208.0	26,946.8	441.4	31.8	384.8	30,338.7
Utah	1,064	29,900	160	125	407.5	4,995.3	454.8	75.0	753.9	21,223.7

Table A.1. Area source fuel consumption by State, 1970 (continued)

State	Residential		Commercial				Industrial			
	Distillate oil (thousand bbl)	Gas (million ft ³)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft ³)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft ³)
Nevada	691	4,300	5	89	24.4	2,425.8	20.1	53.4	45.1	3,428.6
New Mexico	275	19,100	2	19	1.8	7,998.2	115.1	11.4	3.3	23,516.9
Arizona	37	19,300	5	7	8.5	8,861.1	20.1	4.2	15.7	20,528.9
Washington	10,982	20,700	} 100	813	2,274.7	8,979.8	} 30.8	487.8	4,208.2	32,317.3
Oregon	5,793	13,900		437	2,017.3	5,281.5		262.2	3,732.0	18,644.9
California	1,274	382,200	10	91	1,453.6	107,561.4	14.4	54.6	2,689.2	206,412.5
Alaska	2,080	3,100	30	161	21.4	2,765.5	480.0	96.6	39.6	4,778.6
Hawaii	169			9	155.6			5.4	287.9	
Total	447,691	3,206,100	13,557	73,650	113,812.0	1,035,900.0	210,552.0	83,490.0	44,190.0	2,664,100.0

Source: Research Triangle Institute.

A.2 Sulfur Emissions Control Alternatives and Costs

There are two classes of control alternatives: (1) removal of sulfur oxides from stack gases and (2) use of low-sulfur fuels (fuel switching). Gas cleaning is technologically more complex, while use of low-sulfur fuels has economic and resource availability complexities. In this study, gas cleaning is considered only for the steam-electric power plants and not for area sources because of the lack of data on boiler sizes and distributions.

A.2.1 Sulfur Oxide Removal from Stack Gases

Sulfur oxide removal from stack gases may be accomplished by adsorption by a dry or wet medium. For both wet and dry, there are regenerable processes (in which the sorbent is regenerated for reuse with a concentrated sulfur-bearing byproduct stream) and throwaway processes (in which the sorbent is discarded along with the captured sulfur values). Of the many processes and process variants currently in various stages of development and/or demonstration and utilization, three were selected for this analysis because it appears that they will be available by 1978: (1) dry limestone adsorption, (2) wet limestone slurry scrubbing, and (3) magnesium oxide (magnesia base) solution scrubbing. These three techniques were chosen because they are representative of a range of control costs and efficiencies.

A discussion of each of these control techniques follows. Their costs are based on EPA studies. The control efficiencies of the three systems costed are summarized in table A.2. The costs are summarized in table A.3.

Table A.2. Steam-electric plant sulfur emissions stack gas control alternatives

Emissions source	Alternative	Description	Removal efficiency (percent)	Input sulfur recovered (percent)
Coal-burning boiler	1	Dry limestone	35	0
	2	Wet limestone	85	0
	3	Magnesia base	95	92*
Oil-burning boiler	1	Dry limestone	55	0
	2	Wet limestone	85	0
	3	Magnesia base	95	92*
Gas-burning boiler	None	--	--	--

*Some sulfur is lost in the bleed stream from magnesia base regenerator which is used to remove impurities.

Source: Research Triangle Institute.

Table A.3. Sulfur emissions control- cost equations for-steam-electric utilities using flue gas desulfurization

$$(1) C_i = (370,000) (B_i)(S) \left[\frac{785.33}{(L \cdot A \cdot M)^{0.28}} + \frac{10.87}{(L \cdot A \cdot M)^{0.57}} \right] + \left[\frac{F_i \cdot S}{M} \right]$$

where:

C_i = total annualized cost of control, 10^9 Btu

L = boiler load factor

A = boiler annual hours

M = boiler capacity in megawatts

S = sulfur content of fuel

$B_1 = 9.0$ 1 = coal burning

$B_2 = 5.4$ 2 = oil burning

$F_1 = 2071.4$

$F_2 = 1240.0$

$$(2) C_j = \left[\frac{162,000 (Z + B_j \cdot S^{0.67} \cdot M^{0.02})}{M^{0.35}} \right] \left[\frac{0.175}{L} \right] + \left[\frac{F_j \cdot S + 1.8}{A} \right]$$

where:

C_j = total annualized cost of control 10^9 Btu, $j = 1$ or 2

L = boiler load factor

A = boiler annual hours

M = boiler capacity in megawatts

S = sulfur content of fuel

$B_1 = 28,600$ 1 = wet limestone

$B_2 = 40,400$ 2 = magnesia base

$F_1 = 1.850$

$F_2 = 0.440$

Z = $[M/150]$ if $M/150 = [M/150]$

$[M/150] + 1$ otherwise as: $[] =$ "the integer part of"

Sources:

Hittman Associates, Inc., Cost Nomographs of Selected Sulfur Dioxide Abatement Methods, Contract No. EHSD-71-43 for Environmental Protection Agency office of Air Programs, Columbia, Md., 1972.

John K. Burchard et al., Some General Economic Considerations of Flue Gas Scrubbing for Utilities, Environmental Protection Agency, Research Triangle Park, N.C., 1972. Also: Private communication with Gary Rochele at EPA.

A.2.1.1 Dry Limestone Adsorption. The dry limestone adsorption system is a low-efficiency (35 to 55 percent control) sulfur oxide collection alternative.

The basic steps involved in this process are (1) grinding limestone to a fine-grained powder, (2) injecting it into the combustion chamber, and (3) collecting the reacted limestone products which then contain sulfur along with other particulates in a high-efficiency electrostatic precipitator.

Pilot plant operation has revealed several problems with dry limestone removal of sulfur oxides which should be mentioned. First, the limestone is not utilized efficiently because the sulfur oxides cannot penetrate into the interior of the particles of lime (calcined limestone). This problem may be accentuated by fly ash coating the surface of the lime particles, particularly in coal-burning boilers, and by fusing of the lime particles (dead-burning) if the grains are overheated in the boiler. Inefficient use of the limestone can be partially overcome by injection of additional limestone. However, this causes additional expense because (1) more limestone must be used, (2) more fuel must be used to calcine the limestone (releasing more sulfur oxides), and (3) additional precipitator capacity and waste disposal handling are required.

A second problem is that under certain conditions some of the initially collected sulfur oxides may be re-released into the gas stream after having been adsorbed. Third, the limestone, lime, and sulfite/sulfate become an added particulate burden. Fourth, the collection efficiency of standard fly-ash electrostatic precipitators is reduced because sulfur oxides, which enhance the efficiency of a precipitator, are reduced.

A.2.1.2 Wet Lime Scrubbing. The chemical reaction involved in wet lime scrubbing is the same as for dry limestone adsorption, namely converting gaseous sulfur oxides to calcium sulfite/sulfate. The reaction takes place in the scrubber, however, rather than in the combustion chamber. The combustion gasses are ducted through a scrubber where they are washed by slurry of water and lime or limestone, resulting in removal of approximately 85 percent of the sulfur oxides (the factor used in this study). Wet lime scrubbing is considerably more economical of lime than dry limestone scrubbing, requiring as little as 10 percent above the theoretical minimum. However, investment costs are higher for the

(usually multiple) wet scrubbers and scrubbing solution handling equipment. Higher costs also result from spent slurry disposal and control, added fuel costs (or lowered generating efficiency) to restore stack gas temperatures lowered by the scrubbing, and additional operation and maintenance costs for the more complex system.

There are three methods of introducing lime into the scrubbing system. In one method, limestone is injected into the boiler in the same manner as the dry limestone process, but a scrubber is used as the collector. In a second method, limestone is introduced into the scrubbing liquor. In a third method, which has been assumed in this study, precalcined lime is introduced into the scrubbing liquor. Introduction of lime into the scrubbing liquor (slurry) reduces the amount of slurry to be handled and utilizes a greater percentage of the calcium input values since lime is more reactive than limestone, while avoiding the plugging and scaling problems resulting from injecting limestone into the boiler.

The total scrubbing system includes the scrubber(s), the scrubbing liquor handling circuit(s), the reheat system, and the associated ductwork and piping. In addition, some sort of slurry disposal system must be included.

The scrubber design assumed in this system is a floating bed (ping-pong ball) scrubber. The maximum gas throughput for which these scrubbers can be designed is currently 300,000 ft³/min, which approximates the gas flow of a 150 MW generating plant. Therefore, further technological economies of scale do not exist for plants of greater than 150 MW capacity. However, some cost savings are possible with the use of multiple units because volume discounts are usually offered and because there is usually some relative savings in installation costs. The scrubbing slurry handling equipment must be designed to adjust lime usage and slurry pH for scrubbing optimization. One slurry handling system is therefore required for each scrubbing unit.

The flue gas reheat system is designed to raise the temperature of the scrubbed gases to provide adequate plume rise. This can be done with a single system for each boiler rather than a separate system for each scrubber.

Disposal of waste slurry is assumed to be by discharge to a pond for settling, with overflow to sewers or a watercourse. Expenses related

to water pollution control from the pond overflow or to ultimate disposal of the dewatered slurry waste have not been included.

A.2.1.3 Magnesia Base Scrubbing. The entire magnesia base scrubbing system, including stack gas reheating, is identical in concept to lime scrubbing. Some simplification of the scrubbing liquor handling system is possible, however, because the liquor is more nearly a solution of magnesium oxide and hydroxide, rather than a slurry such as with limestone or lime. This factor also allows a higher control efficiency than for lime scrubbing, typically 95 percent. However, the high cost of the magnesium oxide reagent and the ease of regenerating it impose additional equipment requirements for economical operation.

The first addition is a thermal decomposition system which dries the magnesium sulfite/sulfate solution and subsequently drives off sulfur dioxide, leaving the magnesium oxide to be reused. A small amount of the magnesium oxide (typically 2 percent of the total throughput) is discarded to prevent buildup of the trace impurities removed from the gas stream during scrubbing. The purified, concentrated sulfur oxide gas stream must then be treated in some way. Among the alternatives which yield marketable byproducts are (1) compression and liquefaction to product liquid sulfur dioxide for sale, (2) conversion to elemental sulfur in a Claus unit using natural gas or some other hydrogen source, or (3) conversion to sulfuric acid in a (contact) sulfuric acid plant. Conversion to sulfuric acid has been chosen for this study since sulfuric acid is a more saleable byproduct than liquid SO_2 and because acid manufacture does not require a hydrogen source.

A.2.2 Fuel Switching

Sulfur emissions from fuel combustion are in direct proportion to the sulfur content of the fuels. Since the sulfur content of coal and residual oil can be specified by customers when purchasing these fuels, there is the opportunity to reduce sulfur emissions by burning fuels of lower sulfur contents than those which would be selected in the absence of a tax on sulfur emissions. Gas has the lowest sulfur content per Btu of the three principal fuels and is therefore a particularly attractive alternative. However, gas supplies are currently limited due to a

regulation-induced shortage.* Switching to low-sulfur fuels is the only control technique usually assumed available to area source combustion. For steam-electric power plants, fuel switching is an attractive alternative because it does not involve the use of new technologies that may not be completely proven.

Fuel switching costs consist of price premiums for low sulfur fuel and, whenever a fuel is used other than that for which the boiler was designed to burn, boiler conversion costs. In this study, a cost of \$11 per billion Btu and \$300 per megawatt have been used for area source and steam-electric boiler conversions, respectively.† Estimation of the fuel price structure under alternative tax rates would ideally involve the use of a general equilibrium-type of model of the demand and supply of fuels. Although development of such a model was beyond the scope of this study, it was possible to include a reasonably complex set of price and fuel supply conditions so that the role of prices in allocating fuels could be explicitly included if not completely satisfactorily modeled. Recent studies by MITRE‡ and Battelle§ provided a basis for developing projections for 1978 of maximum domestic production of coal and residual oils by source location and sulfur content and by minimum price levels sufficient to cover costs and to provide reasonable profit levels. The supply of imported residual oils is assumed to be perfectly elastic. Based on these prices plus the estimated transportation cost, cost functions have been developed for each fuel user. The analysis of fuel switching, as an alternative control system for steam-electric utilities and area sources, has been based on the fuel cost estimates with consumption of domestically produced fuels constrained by projected national production. It is recognized that the supply functions assumed for this study do not allow for the likelihood of shifts in supply over time due to increases in the prices of some fuels nor do they recognize the position of the United States

*MacAvoy, Paul W., "The Regulation-induced Shortage of Natural Gas," Journal of Law and Economics, Vol. 14, No. 1 (April 1971), pp. 167-98.

†Derived from data presented in Ehrenfeld, J.R. et al, Systematic Study of Air Pollution from Intermediate-size Fossil-fuel Combustion Equipment, Walden Research Corp., Cambridge, Mass., July 1971.

‡MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972.

§Battelle Memorial Institute, Energy Quality Model--1972, unpublished.

as a consumer of the world's oil supply. However, over the relatively short time frame involved and considering the scope of this study, they represent a reasonable set of working assumptions.

A.2.2.1 Coal. Coal is the major fuel for steam-electric power generation. The production of coal is from coal reserves that vary with respect to location, characteristics, and amount. Although total coal reserves are estimated to be about 2.9 trillion tons, only a small part of this total is precisely located ("known") and recoverable with current technology. These currently known recoverable reserves, estimated to be 50 percent of known reserves, are as follows: anthracite, 6,368 million tons; bituminous, 130,755 million tons; subbituminous and lignite, 59,931 tons.*

Known recoverable reserves of coal are unevenly distributed among the major coal-producing regions. The region with the largest share of these reserves is the Northern Rocky Mountain region (table A.4) which is, of course, located long distances from the nation's major population centers where most coal is consumed.

The sulfur content of coal, which is critical in determining emissions from coal combustion, varies by type of coal. All anthracite and most subbituminous coal and lignite reserves have low sulfur content (1 percent or less sulfur by weight). Almost one-half of all recoverable coal reserves, however, is bituminous coal whose sulfur content varies considerably. Most of the bituminous reserves (about 57 percent) are of high sulfur content (over 2.0 percent). Less than one-third of the reserves (about 30 percent) is of low (1 percent or less) sulfur content. The remainder of the bituminous coal reserves (about 13 percent) is estimated to be of medium (1.1 to 2.0 percent) sulfur content.

In 1970, the more than 5,000 active bituminous coal and lignite mines operating at an average of 82 percent capacity produced about 603 million tons.† However, not all of the 603 million tons are available for consumption by the steam-electric plants and area sources for the following reasons: (1) Most coal (71 percent) is cleaned to reduce impurities and enhance the Btu content; as a result about one-fourth of this tonnage becomes

*MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, pp. 18-19.

†Minerals Yearbook, Vol I, U.S. Department of Interior, Bureau of Mines, p. 329.

Table A.4. Geographic-distribution of known recoverable reserves of coal

Coal-producing region	Known recoverable reserves (billion tons)
Northern Appalachian	16
Southern Appalachian	12
Eastern Interior	62
Western Interior	10
Northern Rocky Mountains	80
Southern Rocky Mountains	17
West Coast	1
Total	198

Source: MITRE Corporation, Survey of Coal Availabilities By Sulfur Content, p. 18.

refuse. (2) Some coal is exported. (3) Finally, some coal is used to produce coke for blast furnaces and for the self-generation of power at steel and rolling mills. These so-called metallurgical coals, usually captive to the consuming industries, must have a property known as caking (or coking) and must be of low sulfur and ash content. As a result, they carry a price premium and should not be considered as possible fuels for consumption by the steam-electric power plants and the area sources. After all these adjustments have been made, MITRE estimates the production of commercial steam coal in 1970 to have been about 363 million tons.*

Table A.5 shows the estimated 1970 production of commercial coal, which is all noncaptive steam coal, by region and sulfur content. The regions east of the Mississippi River dominate production of all coals; however, western reserves of low sulfur coal are many times greater than those in the eastern regions.

Table A.6 shows maximum 1978 coal production levels. These estimates are given by region and sulfur content and assume current production costs.

*MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, pp. 29-34.

Table A.5. Production of commercial bituminous and subbituminous coal--1970
(millions of tons)

Region or basin	Sulfur content (by weight, dry basis)									Total
	≤ 0.7	0.8-1.0	1.1-1.5	1.6-2.0	2.1-2.5	2.6-3.0	3.1-3.5	3.6-4.0	> 4.0	
Northern Appalachian	0.06	1.07	4.1	31	18	14	7.8	5.4	0.45	81.88
Southern Appalachian	17.00	46.00	16.0	14	4.3	0.22	2.2	0.0	0.0	99.72
Eastern Interior	0.96	--	7.8	9.2	3.7	7.4	47.0	51.0	19.0	146.06
Western Interior	0.33	0.19	0.34	0.12	0.14	0.56	0.56	0.64	5.2	8.08
Northern Rocky Mountains	12.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.3
Southern Rocky Mountains	12.7	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.4
West Coast	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Total United States	43.75	49.06	28.24	54.32	26.14	22.18	57.56	57.04	24.65	362.94

Source: MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, pp. 26-34.

Table A.6. Projected maximum production of commercial bituminous coal--1978
(millions of tons)

Region or basin	Sulfur content (percent, by weight, dry basis)									Total
	≤ 0.7	0.8-1.0	1.1-1.5	1.6-2.0	2.1-2.5	2.6-3.0	3.1-3.5	3.6-4.0	> 4.0	
Northern Appalachian	0.07	1.92	10.85	36.94	26.05	17.18	10.26	7.46	0.69	111.42
Southern Appalachian	26.4	54.98	20.19	16.03	4.85	1.17	2.2	0.01	0.03	125.86
Eastern Interior	1.04	0.85	13.71	14.49	8.17	27.22	86.56	102.68	40.25	294.93
Western Interior	0.36	0.33	0.82	0.35	1.97	0.94	2.78	6.41	17.48	31.45
Northern Rocky Mountains	49.17	31.86	0.05	0.48	0.11	0.05	0.01	---	0.16	81.89
Southern Rocky Mountains	34.82	19.92	0.04	0.38	0.0	0.0	0.0	0.0	1.00	56.16
West Coast	1.43	0.37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.80
Total United States	113.29	110.23	45.66	68.67	41.15	46.56	101.81	116.56	59.61	703.51

Source: Developed from data in Survey of Coal Availabilities by Sulfur Content, MITRE Corporation, May 1972, pp. 26-34.

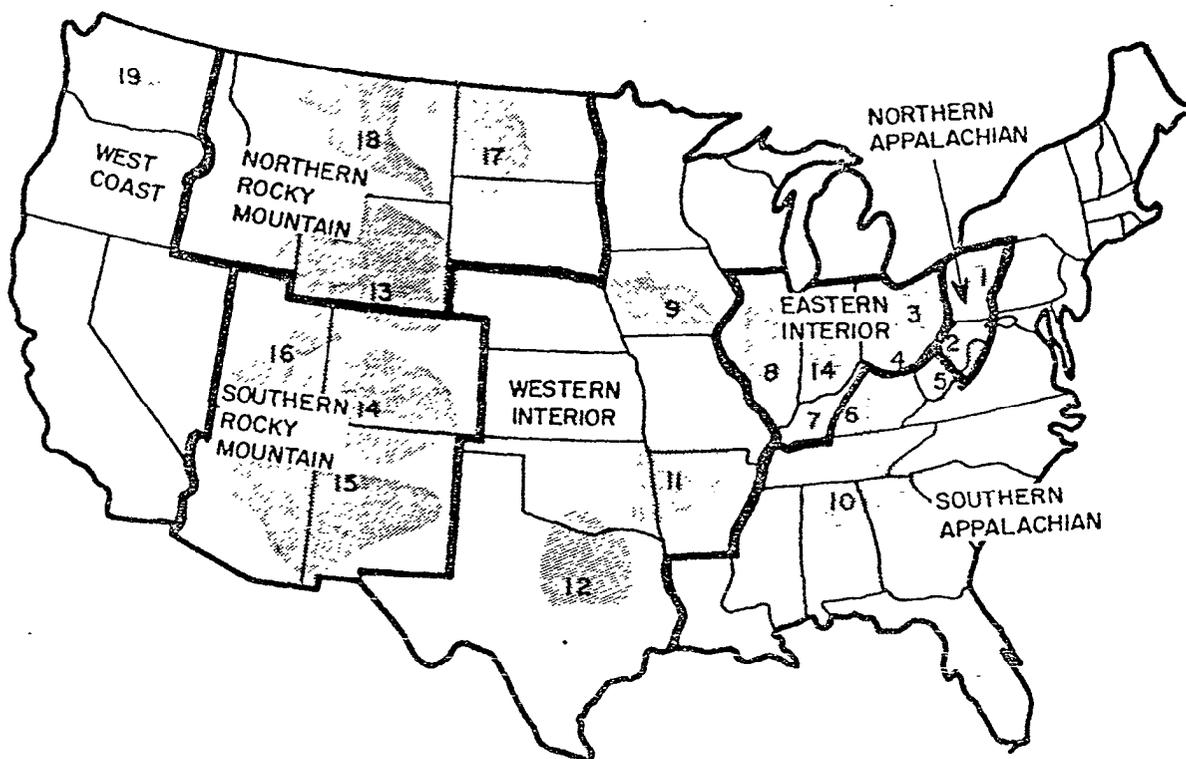


Figure A.1. Coal-producing districts (Source: Department of the Interior).

They are based on the assumption that production growth will not occur unless it is maintainable for at least 20 years.*

These projections of 1978 production levels for the major coal-producing regions have been converted to Btu's. Projections of coal supply used by Battelle were employed here to derive proportions and the values in table A.5 across the 79 coal-producing districts (fig. A.1). It would require 4 years to attain the indicated levels in the eastern regions and 3 years in the western regions.† For purposes of this analysis, they have been used to provide upper limits on coal supplies.

Coal prices will influence fuel selections by the fossil fuel combustion sources. As shown in figure A.2, coal prices have recently been rising rapidly. In part, these price increases may be due to

*MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, p. 79.

†MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, p. 81.

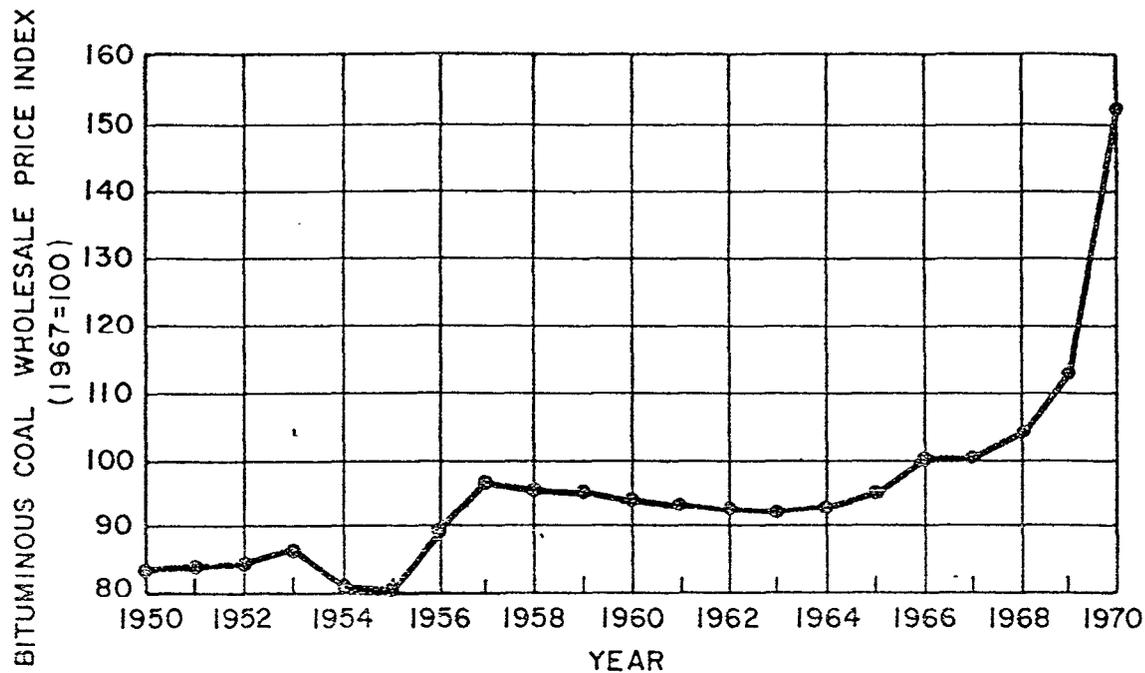


Figure A.2. Bituminous coal price trends (Source: Department of Labor).

increases in the demand for low sulfur coals as a result of air quality regulations. For this study it is desirable to have sets of fuel prices by sulfur content and location which reasonably reflect supply conditions from which to estimate fuel cost increases due to fuel switching.

Low sulfur coals are in limited supply in the Eastern United States, most deposits being in the Southern Appalachian Region. Western low sulfur fuels are more abundant but may have high delivered costs due to their distance from markets and their lower Btu content.

Initial estimates of the prices of all coals were derived from the Battelle study.* As they explain, however, their prices were minimum price estimates. Many prices may be bid upward in the presence of air quality regulations, regardless of whether emissions standards or taxes are used to induce compliance.

*Battelle Memorial Institute, Energy Quality Model--1972, unpublished.

Using these estimates as a floor below which prices are not expected to go, the emissions response model was run to derive projections of steam-electric utilities demand for each coal type. Fuel demand and supply for each sulfur content were then compared on a national basis. When demand exceeded supply, the regions contributing to the excess were identified from the disaggregated district tables. Prices of fuels for which the demand exceeds supply were incremented and the model was rerun. Several iterations were required, until a price structure was developed that reflected market conditions. It is recognized that this approach is quite simplistic when compared with a more sophisticated approach such as linear programming (which would have resulted in a unique price structure). Such, an approach, however, would have been beyond the scope of this study. For example, in this model each utility can select from among four control alternatives, (i.e., three hardware and one no-hardware), nine sulfur contents, and 19 regions for coal alone; a total of over 500 combinations exist. There are about 1,000 utilities. The linear programming model implied by the size of the model would have been substantial. Yet it was recognized that (1) the demand for these fuels was interrelated, (2) each utility faces a large number of alternatives (not merely "low sulfur" fuel as implied in many studies), and (3) relative fuel prices will be critical in the selection from among control alternatives. The approach employed in this study as discussed above does offer the opportunity to incorporate a fair degree of sophistication into the analysis of the response of fuel combustion sources to an emissions tax. The resulting price levels are presented in table A.7. For ease of calculation, an average sulfur content was used rather than a range as was presented earlier.

A.2.2.2. Oil. Distillate and residual fuel oils are important sources of energy for steam-electric utilities and for area heating sources. Domestic supplies of those fuel oils are functions of the supply of crude and production decisions on the proportion of the total that is to be refined into fuel oil versus other petroleum products. An increase in the share going to gasoline, for example, tends to reduce the availability of fuel oil.

Domestic supplies of residual and distillate oil have been insufficient to meet demand in recent years, as shown in figure A.3. As a result,

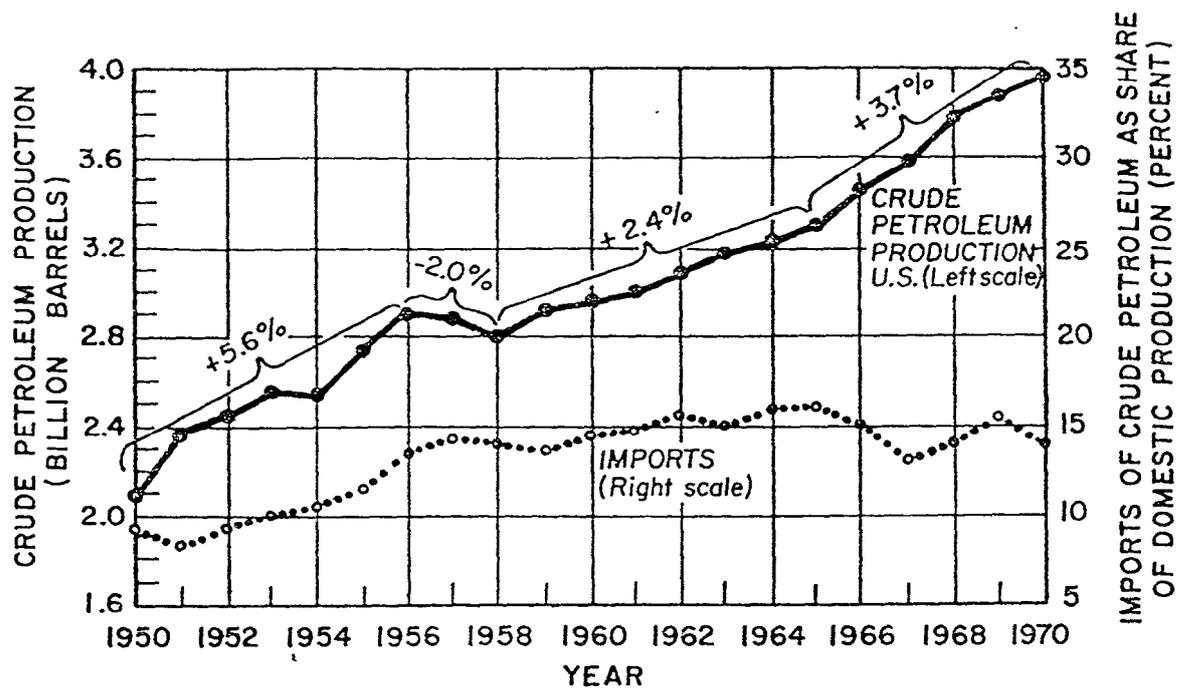


Figure A.3. Sources of supply of petroleum (Source: Department of Interior).

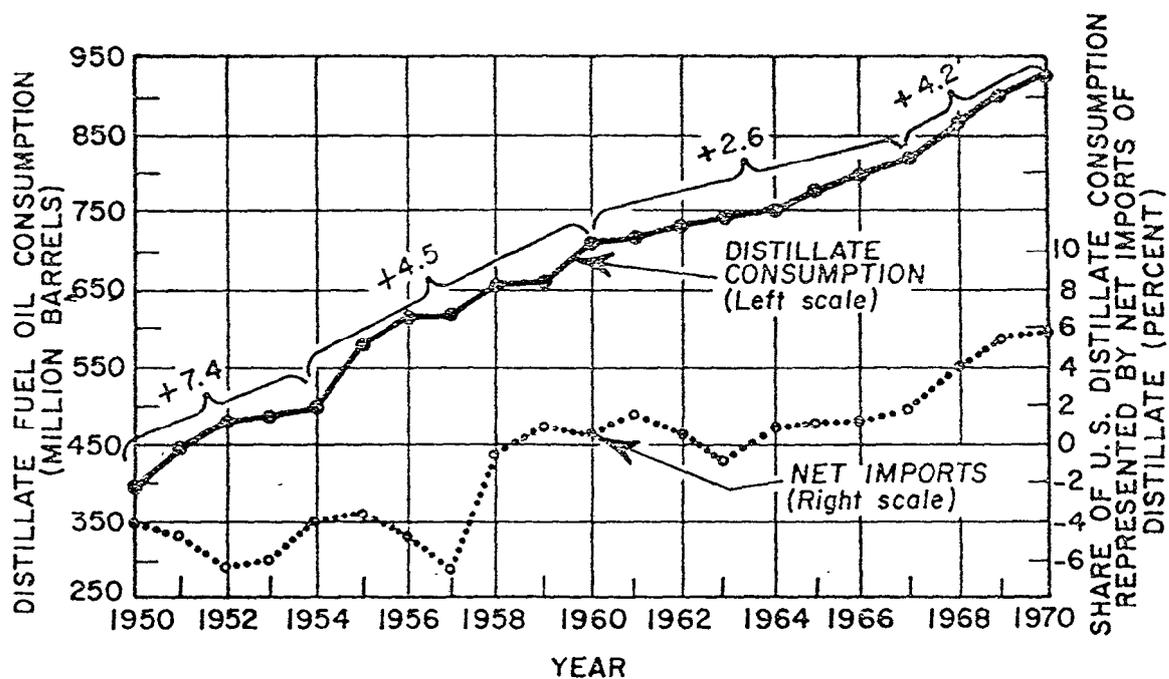


Figure A.4. Distillate consumption (Source: U.S. Department of Interior).

Table A.7. Coal prices by district
(dollars per billion Btu)

Coal district	Sulfur content (percent)								
	0.7	0.9	1.3	1.8	2.3	2.8	3.3	3.8	5.0
1	424	394	334	300	273	269	249	247	246
2	430	375	340	301	300	298	245	240	235
3	414	340	291	264	239	238	237	217	216
4	385	352	316	284	280	275	270	265	260
5	395	373	331	305	282	280	279	278	277
6	385	364	315	275	254	249	243	240	243
7	420	415	340	323	261	247	224	215	210
8	460	390	330	300	259	235	234	227	225
9	422	385	364	330	323	284	270	267	266
10	421	390	355	311	276	275	275	274	273
11	422	412	364	341	320	309	289	287	286
12	422	385	364	330	301	299	298	287	261
13	385	343	342	342	341	341	341	---	341
14	385	343	334	323	---	---	---	---	320
15	385	333	331	330	---	---	---	---	325
16	385	333	330	326	---	---	---	---	300
17	395	358	355	353	348	348	348	---	351
18	379	325	320	318	316	314	313	---	313
19	360	315	---	---	---	---	---	---	---

Source: Adapted from Battelle Memorial Institute, EPA Energy Quality Model, September 1972.

imports of both crude and refined oils have increased and do supply a substantial share of the market. Table A.8 shows the 1970 sources of residual fuel oil. The importance of imports and their country of origin are shown. The data may understate the role of the Middle East and overstate that of Europe, however, since some Middle East crude is refined in Europe and then shipped to the United States. Trends in the share of crude and residual oil imports from the Middle East are shown in Table A.9. A recent study* estimated that the import share of domestic consumption of fuel oil will double between 1970 and 1980.

A.2.2.2.1 Distillate. Distillate production represents a declining but substantial share of domestic oil production (figure A.4). While some distillate is used by steam-electric utilities for peak load power generation, it represents only a small energy source for these utilities. However, distillate is an important source of energy for the area sources where it is used as a power generating fuel and, more commonly, as a heating fuel.

*National Petroleum Council, U. S. Energy Outlook, Vol. 2, November 1971, p. 57.

Table A.8. Sources of residual fuel oil, 1970

	(thousand barrels)
Domestic sources of supply	266,228
Production	257,510
Crude used directly as residual	4,317
Reductions in stocks	4,401
Domestic consumption	804,287
Exports	19,786
Imports	557,845
North America (Canada and Mexico)	14,147
Central America and Caribbean	261,299
South America	220,842
Europe	58,251
Middle East	1,554
Africa	1,616
Asia	136

Source: Minerals Yearbook, U.S. Department of the Interior, Bureau of Mines, 1970

Table A.9. Crude and residual oil imported into the United States from the Middle East

Year	Crude oil		Residual oil	
	Amount (thousand barrels)	Share of Imports (percent)	Amount (thousand barrels)	Share of imports (percent)
1967	67,977	16.5	5,421	1.4
1968	72,330	15.3	4,431	1.1
1969	61,616	12.0	4,872	1.1
1970	61,892	12.8	1,554	0.3
1971	124,155	20.2	4,226	0.7

Source: Minerals Yearbook, U.S. Department of the Interior, Bureau of Mines.

No attempt has been made in this study to assess future supplies of distillate. The assumption has been made that distillate will be available in quantities sufficient to meet projected demands. For this study, it has been assumed that only area sources consume distillate fuel. The sulfur content is 0.10 pounds per million Btu regardless of origin, and consumers are assumed to have perfectly inelastic demand for distillate. Thus, it has not been necessary to develop any structure of prices since, for any tax rate, consumption will remain constant and tax payments made on emissions.

A.2.2.2.2 Residuals. Domestic production of residual oil provides only about one-third of consumption (fig. A.5). Residual fuel oils are a significant source of energy for steam-electric utilities. In 1970 they accounted for about 15 percent of total Btu's consumed.* While domestic production is limited, the supply of foreign residuals is assumed to be perfectly elastic.

MITRE† has provided projections of domestic residual oil production for the 5 PAD districts‡ (table A.10). In order to use the Battelle price and transportation data, these projections were distributed among 12 oil-producing regions (fig. A.6) using proportions derived from the Battelle study.

Minimum prices by oil-producing regions were presented in the Battelle study.

Initial runs of the emissions model indicated that some Battelle prices were not high enough to ration projected production. These prices were raised in iterative fashion as they were for coal until quantity demanded was reduced to levels more consistent with projected production. The resulting price structure is presented in table A.11. Again it is recognized that this approach is a considerable simplification of the market-adjustment process that may actually take place. Yet the procedure does provide a set of prices from which relative prices can be obtained

*National Coal Association, Steam-Electric Plant Factors, 1971, Washington, D.C., 1972, p. 52.

†MITRE Corp., Survey of Coal Availabilities by Sulfur Content, May 1972.

‡These refining districts correspond with groupings originated by the Petroleum Administration for use during World War II which were called PAW districts. The PAW districts were later changed to PAD (Petroleum Administration for Defense) districts.

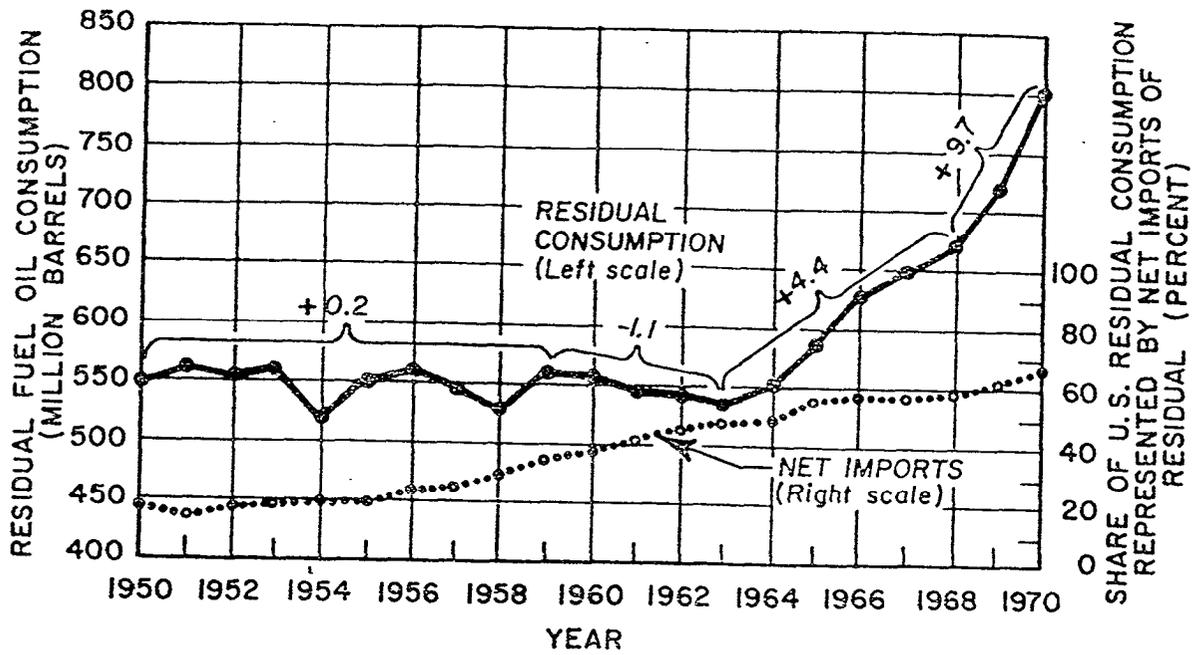


Figure A.5. Residual fuel oil consumption (Source: U.S. Department of the Interior).

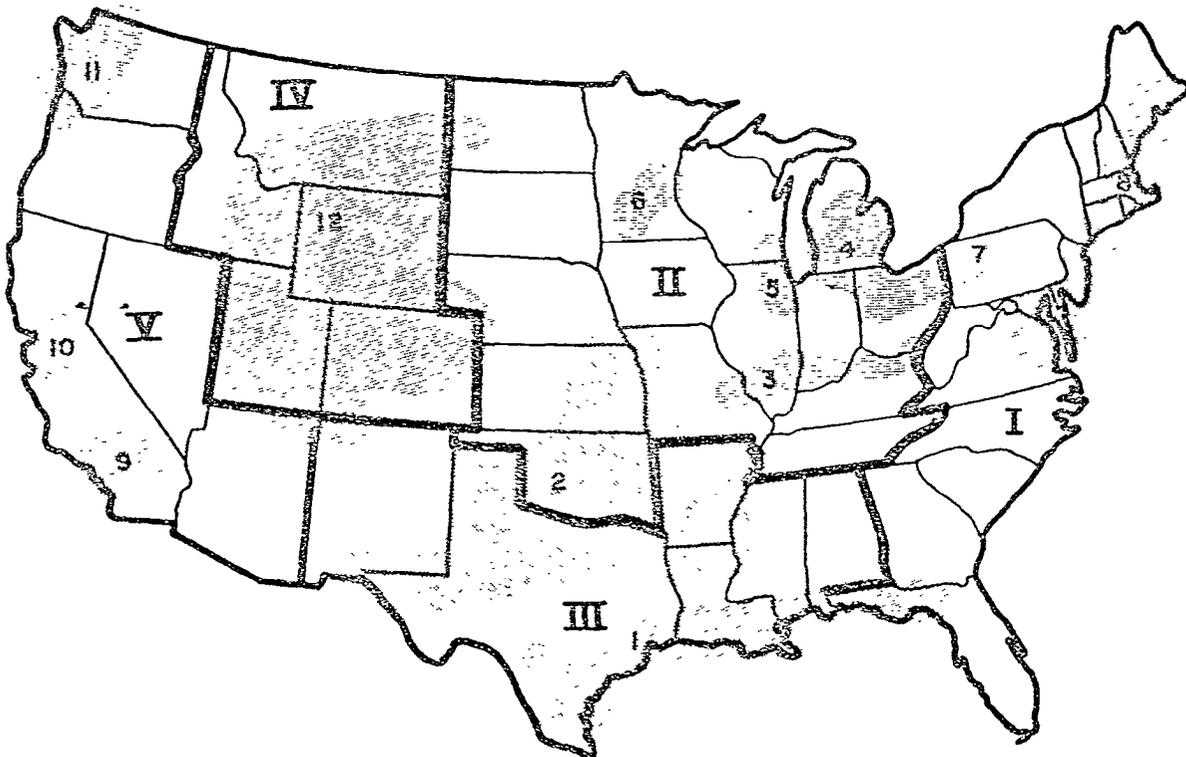


Figure A.6. Oil-producing regions (Source: U.S. Department of the Interior).

Table A.10. Projected maximum U.S. production of residual oils--1978
(billion Btu)

District	Sulfur content (percent)					Totals
	< 0.4	0.4-0.82	0.83-1.65	1.66-2.94	> 2.94	
I: East	8.6	0	0.1	0	0.0	8.7
II: Midwest	121.1	104.0	60.4	31.8	13.9	331.2
III: Southeast-Southwest	854.6	530.8	108.4	207.0	0	1700.8
IV: Rocky Mountain	97.0	16.0	32.9	9.7	34.8	190.4
V: West	39.8	40.1	109.3	121.3	45.2	355.7
Total	1121.1	690.9	311.1	269.8	93.9	2586.8

Source: MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, p. 18.

Table A.11. Oil prices by region
(dollars per billion Btu)

Oil region	Sulfur content (percent)				
	0.4	0.6	1.2	2.3	3.0
1	445	377	338	291	290
2	444	376	350	332	331
3	540	459	399	356	351
4	545	459	410	360	352
5	517	470	435	415	406
6	505	NA	NA	NA	NA
7	517	NA	NA	NA	NA
8	517	NA	NA	NA	NA
9	499	NA	375	336	302
10	489	412	375	335	321
11	495	424	378	354	345
12	489	412	365	320	315
Gulf Coast	445	377	338	291	290
Great Lakes	517	470	435	415	406
West Coast	499	422	375	336	302
East Coast	517	490	390	313	266

Source: Adapted from Battelle Memorial Institute, EPA Energy Quality Model, September 1972.

to provide more realistic projections of the cost of control for fuel switching than would a single premium for low sulfur oil.

A.2.2.3 Gas. Gas is an important energy source for steam-electric utilities and the area sources. In addition, gas is also a competitor of electricity, primarily in the commercial and residential heating markets.

No attempt has been made in this study to project the future supply of gas. It has been assumed that sufficient supplies of gas will be available to current users of gas. However, no sources are permitted to switch to gas from coal or oil.

A.2.2.4 Transportation Costs. Transportation costs are an important element in the delivered prices of coal, oil, and gas. In the future, they may assume even larger importance than today, since large reserves of low sulfur coal, while available, are located long distances from the population centers where most fuel is consumed. It is necessary, therefore, to incorporate transportation costs into the model that predicts fuel prices to be faced by users.

The transportation matrix developed by Battelle for EPA has been used. This matrix estimates shipping costs from 19 coal-, 12 oil-, and 12 gas-producing regions to each State. The location of each of the nation's steam-electric utilities has been identified in terms of one of these destinations. The transportation costs are approximations of actual costs based on the typical modes used for shipping each fuel, their per mile costs, and distance from origin to destination.

These costs were put on a Btu basis to make them comparable with other fuel costs. The average Btu contents of residual oil and gas used in this study are shown in table A.12.

Table A.12. Oil and gas average Btu contents

Fuel	Average Btu content (millions)	Fuel content
Residual oil	6.287	Per barrel
Gas	1.030	Per million cubic feet

Source: Research Triangle Institute.

The Btu contents of coal vary significantly among origins, especially between the Appalachian and Rocky Mountains. For this reason, it was necessary to adjust the coal transportation costs origin-by-origin. The coal Btu contents are presented in table A.13.

A.2.3 Emissions Reductions and Costs

Cost of control functions for all steam-electric power plants and area sources have been developed based on the costs and effectiveness of the control alternatives costed above, a listing of the nation's utilities which includes relevant parameters for emissions and control cost estimation and State-by-State demands for Btu's by the area sources. These functions are minimum cost functions for achieving sulfur emissions reductions from these two sources.

The long-run industry total and marginal costs of emissions reductions are shown in figures A.7 through A.10. The continuity of these estimated functions is probable, due to the large number of sources and control alternatives.

Table A.13. Coal average Btu contents by origin

Coal-producing region	Average Btu per ton (millions)
1	27
2	27
3	24
4	25
5	28
6	27
7	24
8	23
9	23
10	23
11	27
12	26
13	23
14	19
15	20
16	19
17	21
18	19
19	17

Source: MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, pp. II-2 through II-5.

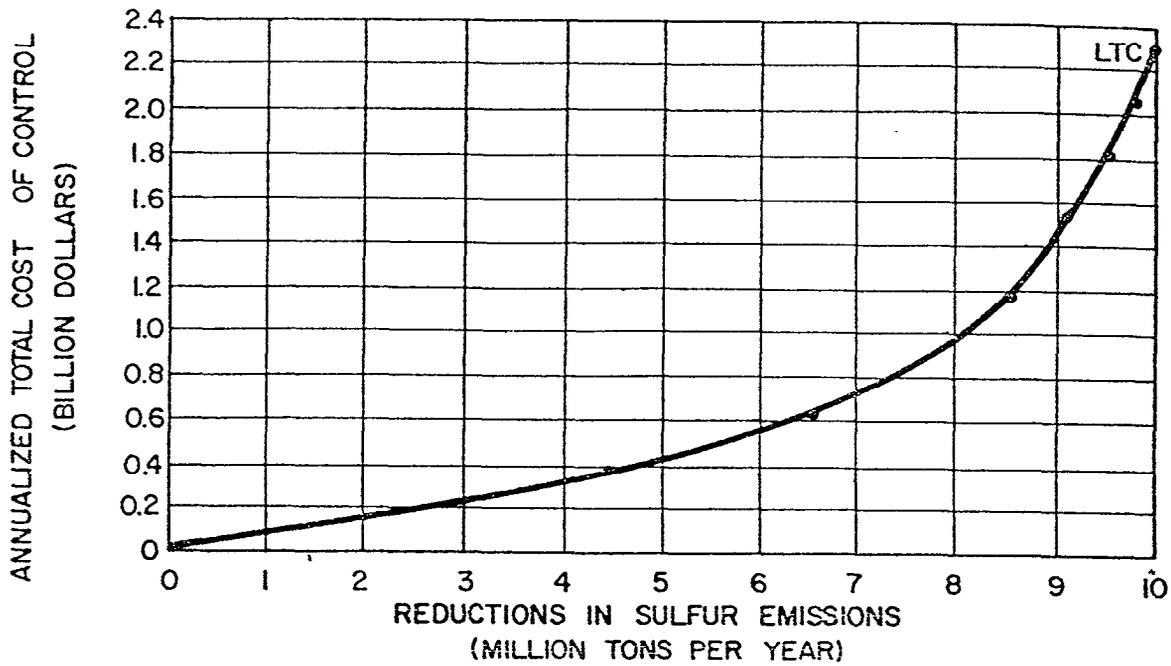


Figure A.7. Total cost* of reductions in sulfur emissions: steam-electric utilities (*does not include emissions tax payments) (Source: Research Triangle Institute).

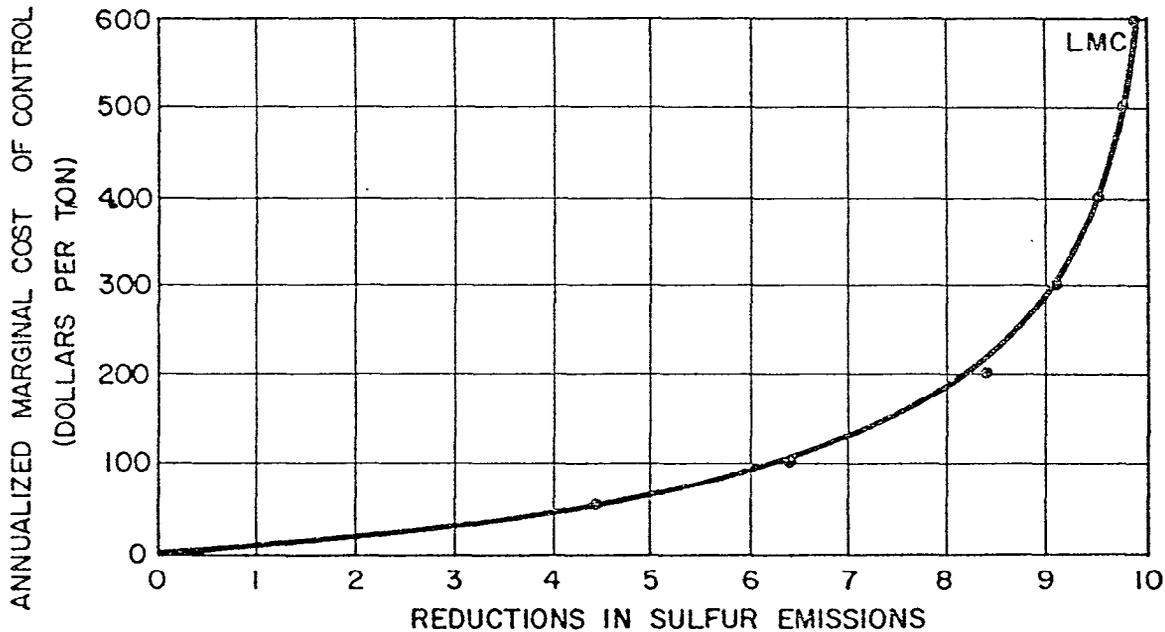


Figure A.8. Marginal cost* of reductions in sulfur emissions: steam-electric utilities (*does not include emissions tax payments) (Source: Research Triangle Institute).

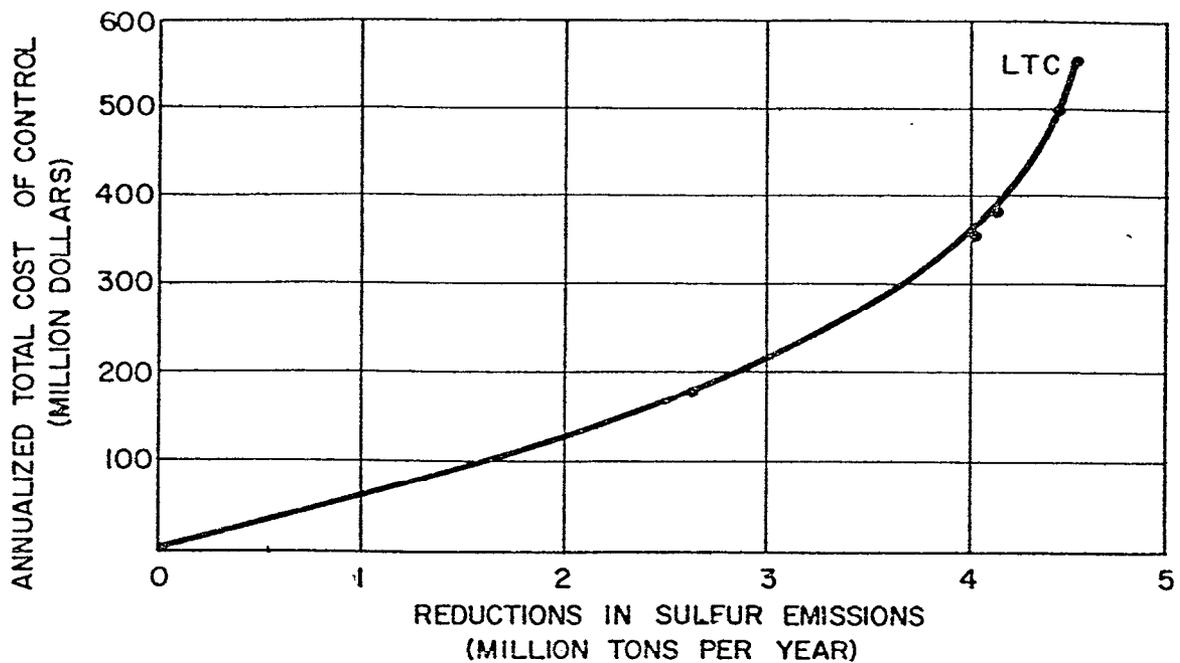


Figure A.9. Total cost* of reductions in sulfur emissions: area sources (*does not include emissions tax payments) (Source: Research Triangle Institute).

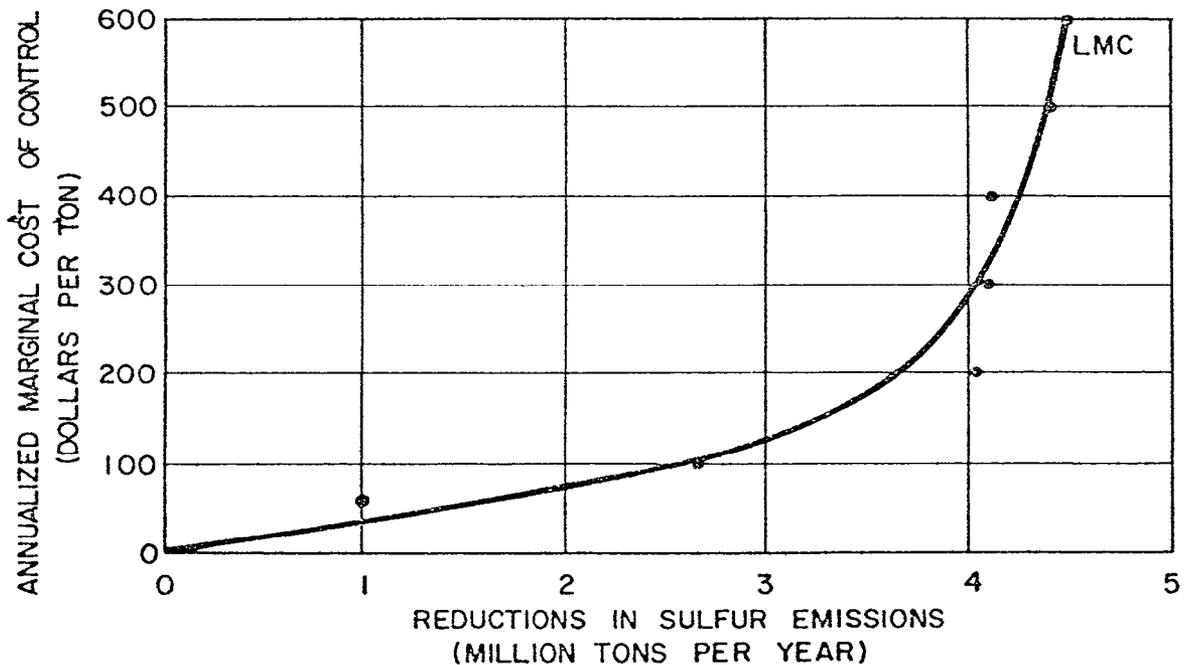


Figure A.10. Marginal cost* of reductions in sulfur emissions: area sources (*does not include emissions tax payments) (Source: Research Triangle Institute).