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ASSESSMENT OF THE DEGREE OF FLEXIBILITY IN FUEL DISTRIBUTION PATTERNS

Industrial Environmental Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

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by

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ABSTRACT

The report gives results of a study to evaluate the potential of fuel switching as an element of an overall strategy for the control of sulfur oxide emissions from stationary sources. Blocks of misplaced fuels (i.e., clean fuels now burned in large sources and dirty fuels now burned in small sources) were identified. Various potential constraints to switching the misplaced fuels were evaluated. These included: equipment constraints, business constraints, and fuel transportation constraints. From these evaluations, the quantities of misplaced fuels were identified which are not limited by any of the constraints, and therefore which can be considered suitable for switching.

TABLE OF CONTENTS

	Page
INTRODUCTION	1
CONCLUSIONS AND RECOMMENDATIONS	2
Coal in Large Sources	3
Coal in Small Sources	4
Oil in Large Sources	4
Oil in Small Sources	4
Natural Gas in Large Sources	4
IDENTIFICATION OF BLOCKS OF MISPLACED FUELS	6
Data Sources	6
The National Emissions Data Systems	8
Results of the Analysis of the NEDS	9
Discussion of the NEDS Results	15
Extrapolation of the NEDS Data	17
FACTORS AFFECTING THE ABILITY TO SWITCH "MISPLACED" FUELS	22
EQUIPMENT CONSTRAINTS TO FUEL SWITCHING	23
Conceptually Possible Fuel Interchanges	24
Performance Problems of Fuel Switching	25
Boiler and Auxiliary Equipment	29
Coal Interchangeability as Related to Firing Method	33
Coal Characteristics	33
Slag-Type Furnace (Cyclone and Some Pulverized Coal)	35
Dry-Bottom Pulverized Coal Furnaces	37
Spreader Stokers	37
Overfeed Stokers	38

TABLE OF CONTENTS
(Continued)

Page

Underfeed Stokers 39

Specific Example of Conversion 39

Population of Convertible Utility Boilers 40

Conclusions 41

BUSINESS-RELATED CONSTRAINTS TO FUEL SWITCHING 42

Summary 43

Utility Fuel Purchasing Practices 44

Coal 44

Oil Use by Utilities 49

Natural Gas 55

Industrial Fuel Purchasing Practices 57

Coal 57

Oil 59

Natural Gas 59

FUEL TRANSPORTATION CONSTRAINTS TO FUEL SWITCHING 61

IDENTIFICATION OF BLOCKS OF FUELS SUITABLE FOR SWITCHING 63

REFERENCES 66

APPENDIX A

LIST OF ELECTRIC UTILITIES WHOSE PROSPECTUSES AND REGISTRATION STATEMENTS WERE EXAMINED TO OBTAIN INFORMATION ON FUEL CONTRACTS AND PURCHASING PROCEDURES 67

APPENDIX B

LIST OF FIRMS AND AGENCIES CONTACTED DURING COURSE OF RESEARCH . . 69

LIST OF TABLES

		Page
Table 1.	Fuel Consumption in the United States by End Use for 1968	7
Table 2.	Aggregated Data from NEDS Point Source Data Bank. Fuel Consumption by Sector, Source Size, Region, Fuel Type, and Sulfur Content	10
Table 3.	Electrical Sector Summary - NEDS Point Source Data	11
Table 4.	Industrial Sector Summary - NEDS Point Source Data	12
Table 5.	Commercial/Institutional Sector Summary - NEDS Point Source Data	13
Table 6.	Actual Fuel Use in 1972 by Consuming Sector	14
Table 7.	Total 1972 Fossil Fuel Use Allocated by Sector, Source Size, Fuel, and Sulfur Content, on the Basis of the NEDS Distribution, 10^{12} Btu/year	19
Table 8.	Possible Interchanges of Fuels in Boiler Furnaces	24
Table 9.	Auxiliary Equipment Needs	32
Table 10.	Trends in Coal Purchases by Utilities Between April, 1973, and June, 1974, by Type of Purchase	45
Table 11.	List of Largest Commitments of Coal Under Long-Term Contract by Selected Utilities	48
Table 12.	Captive Coal Production by Electric Utilities, 1973	50
Table 13.	Coal Reserves Held by Utilities	51
Table 14.	Trends in Utility Purchases of No. 6 (Residual) Fuel Oil Between April, 1973, and June, 1974	52
Table 15.	Changes in Natural Gas Use by the Electric Utilities Sector 1972-1980 and Relative Dependence on Natural Gas	56
Table 16.	Coal Equivalent of Misplaced Clean Fuels in Large Sources	62

LIST OF FIGURES

		Page
Figure 1.	Approximate Relationships of Furnace Exit Gas Temperature to Heat Release Rate for Various Fuels . .	27
Figure 2.	Steam Generating System Showing Typical Location of Soot Blowers	28
Figure 3.	Spot Coal Purchases as Percent of Total Coal Purchases by Utilities, June, 1974	47
Figure 4.	Spot Purchases of Oil as Percent of Total Purchases by Utilities, June, 1974	54

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INTRODUCTION

This study was conducted for the Industrial Environmental Research Laboratory of the U.S. Environmental Protection Agency in support of its evaluation of the potential of fuel switching as an element of an overall strategy for control of sulfur oxide emissions from stationary sources. A straightforward means for SO_x control is to burn a clean fuel, i.e., a fuel with sufficiently low sulfur content that the SO_x emission standards can be met without any post-combustion treatment of the stack gas to remove SO_x. Such clean fuels include natural gas, distillate fuel oil, low sulfur residual fuel oil, and low sulfur coal. When limitations were placed on sulfur oxide emissions from stationary sources, compliance was achieved in many cases by switching to a clean fuel. However, the supply of clean fuels is insufficient to meet the demand of all stationary combustion sources in this country, and, as a result, "dirty" fuels, such as high sulfur residual fuel oil and high sulfur coal, must still be used. Technology for the control of SO_x emissions when "dirty" fuels are used has been under development and includes stack gas scrubbing, fluidized-bed combustion, and various coal conversion processes. At the present time, the projected economy of scale of these technologies is such that they are not expected to be practical for use by small sources. In the light of these considerations, an optimum strategy would be to burn clean fuels in small sources, and to use high sulfur fuels, with an associated control technology, in large sources. This pattern of fuel use would result in lower total emissions of SO_x from all stationary sources. The benefits of such fuel switching would be to reduce the ambient air concentrations of SO_x with the resultant reduction in adverse health effects due to SO_x in the air.

The objective of this study was to assess the degree of flexibility in fuel distribution patterns in order to estimate the potential for switching fuel to achieve the optimum fuel-use pattern to achieve minimal air pollution. This required an estimation of the quantity and location of misplaced blocks of fuel which might be considered for switching from one user to another. In the present context, a misplaced fuel is a clean fuel being burned in a large source or a dirty fuel being burned in a small source. For the purposes of this study, a large source is defined as a source having a heat input greater than 250 x 10^6 Btu/hr. This is the lower limit for application of New Source Performance Standards and therefore it is an appropriate definition in the context of this study. For an electric power plant with a heat rate of 10^4 Btu/kwhr, this is equivalent to 25 MW. Various potential constraints to switching the misplaced fuels were evaluated:

(1) Equipment-related factors which prevent switching from one type of fuel to another
(2) Business-related factors which tie a user to a specific fuel
(3) Fuel transportation factors which might limit the quantities of a specific fuel available in a region or location.

Cost factors associated with fuel switching were not evaluated as these would be largely site dependent. From these evaluations the quantities of misplaced fuels which are not limited by any of the constraints, and therefore can be considered suitable for switching, were identified.

CONCLUSIONS AND RECOMMENDATIONS

The following quantities, in 10^{12} Btu/year, of misplaced fuels have been estimated:

Fuel	Large Sources	Small Sources
Misplaced coal	1,804	2,323
Misplaced oil	2,978	3,479
Misplaced natural gas	10,457	--
Total	15,239	5,802

Evaluation of the constraints which limit exchange of these fuels leads to the following general conclusions:

- Gas- or oil-fired boilers cannot be switched to coal unless they were originally designed for dual fuel or designed for coal and subsequently converted.
- Coal-fired boilers which were converted to oil may not be reconvertible.
- One coal can be exchanged for another coal if proper care is taken to ensure that the properties of the new coal are compatible with the furnace and boiler design. Derating of the boiler is often required.
- Approximately 75 percent of utility purchases of coal are on a long-term contract basis.
- Industrial coal is purchased mainly on a spot basis.
- Captive production of coal is less than 10 percent of the total coal production.
- Long-term contracts for oil and gas do not appear to be a barrier to switching.
- Transportation constraints appear to be less restrictive than equipment and business factors.

Estimates of the magnitudes of possible specific fuel exchanges are given in the following paragraphs.

Coal in Large Sources

Low-sulfur coal in large sources can be replaced by high-sulfur coal or high-sulfur residual oil. Equipment limitations can be overcome in this case. Business constraints in the form of long term contracts will be more limiting. Assuming that such contracts are about uniformly distributed with respect to low- and high-sulfur coal, 25 percent of this block, or 450×10^{12} Btu/year, would be expected to be purchased on a spot basis and, therefore, free for switching.

Coal in Small Sources

High-sulfur coal in small sources can be replaced by low-sulfur coal, by low-sulfur residual oil, by distillate oil, or by natural gas. Again, equipment constraints can be overcome and the primary limitation is that of long-term contracts. Assuming the 25 percent of the utility coal, and all of the industrial and commercial coal is free from this restraint, about 2000×10^{12} Btu/year would be available for switching.

Oil in Large Sources

Low-sulfur oil can be replaced with high-sulfur oil, or by high-sulfur coal, if the boiler were originally designed for coal. Boilers which can be converted to coal represent about 1200×10^{12} Btu/year. The remainder could be switched to high-sulfur residual oil, thus the entire block, about 3000×10^{12} Btu/year, is essentially available for switching. The limitation would be the availability of the replacement fuel.

Oil in Small Sources

High-sulfur oil in small sources can be replaced by low-sulfur residual oil, by distillate oil, or by natural gas. Equipment constraints can be overcome. Little of the high-sulfur oil is expected to be under long-term contract, thus essentially all of this block, or about 3500×10^{12} Btu/year, is available for switching.

Natural Gas in Large Sources

Natural gas cannot be replaced by coal unless the boiler were originally designed for coal. Only about 600×10^{12} Btu/year of the natural gas-fired boiler capacity could be fired with high-sulfur coal. The only other replacement fuel for this large block is high-sulfur residual oil. This change can be accomodated with respect to equipment factors. The primary limitation would be the availability of the replacement fuel.

The quantities of misplaced fuels which are available for exchange are sufficiently large that fuel switching has definite potential as a component of EPA's overall strategy for control of sulfur oxide emissions from stationary sources. In view of this conclusion, it is recommended that the next logical steps be taken, namely:

(1) Assessment of the various means by which fuel switching could be effected, and a determination of EPA's role in encouraging fuel exchange

(2) Assessment of the costs which would be incurred in selected, specific, fuel-exchange situations.

IDENTIFICATION OF BLOCKS OF MISPLACED FUELS

The first step in the assessment of the potential of fuel switching as a control strategy for SO_x emissions was to identify blocks of misplaced fuel. Inspection of end-use fuel-consumption patterns for the United States shows that a few large blocks represent a large fraction of the total energy consumed. A listing of fuel consumption in 1968 is given in Table 1. Residential and commercial space heating utilizes large blocks of oil and natural gas. Most of this is correctly placed as distillate fuel oil, a clean fuel, is the petroleum fraction normally used in such applications. Since these are small sources, the use of clean fuels is correct in the context of this study. In the industrial sector large blocks of each of the fossil fuels are used for process steam and for direct heat. It is not possible to state whether these blocks are misplaced or not. The size of the source and the sulfur content of the fuel must be known in order to identify what portion is misplaced. The same conclusion applies to the blocks of fuel used in the generation of electricity.

Data Sources

The data required for the complete identification of misplaced blocks of fuel include: location and size of individual combustion sources, type of fuel, sulfur content of fuel, and end-use sector. Most of the available information pertinent to this is incomplete in one respect or another. For example, very extensive data exists on the sulfur content of coal. Two Bureau of Mines reports[1,2] give organic, pyritic, and sulfate sulfur analyses on about 2,900 samples which include most of the coalbeds in the United States. Other publications, such as Minerals Yearbook, give data on the quantities of coal consumed by various end-use sectors. These two sets of data cannot be combined to yield the type of information required for this analysis since the sulfur analysis data does not include any specifics on how and where each coal is consumed,

TABLE 1. FUEL CONSUMPTION IN THE UNITED STATES BY END USE FOR 1968[(a)]

End Use	Direct Consumption 10^{12} Btu/year Coal	Oil	Natural Gas	Purchased Electrical Energy 10^{12} Btu/year Coal	Oil	Natural Gas
Residential						
Space heating		2,988	3,236	258	43	118
Water heating		146	979	350	58	159
Cooking		49	325	151	25	68
Clothes drying		9	58	81	13	37
Refrigeration			5	394	65	179
Air conditioning			3	243	40	111
Other				711	118	324
Subtotal		3,192	4,606	2188	362	996
Commercial						
Space heating	568	2,405	1,209	Nil	Nil	Nil
Water heating			422	132	23	60
Cooking			117	13	2	6
Air conditioning			97	582	96	265
Refrigeration				384	63	175
Feedstock		984				
Other				587	97	268
Subtotal	568	3,389	1,845	1698	281	774
Industrial						
Process steam	2349	1,986	5,797			
Electric drive				2634	488	1353
Direct heat	3025	808	2,771	179	33	92
Feedstock	147	1,600	455			
Electrolytic Processes				388	72	199
Other				109	20	56
Subtotal	5521	4,394	9.023	3310	613	1700
Totals	6089	10,975	15,474	7196	1256	3470

(a) Source: Stanford Research Institute, "Patterns of Energy Consumption in the United States", pp 26-29 (1972).

and the consumption data does not give sulfur analysis. A similiar situation exists for petroleum products. Mineral Industry Surveys, published by the Bureau of Mines, report data on the sulfur content of various petroleum fractions without any information on end use, while publications such as Petroleum Facts and Figures give extensive data on end use of fuel oils without any information on sulfur content. Again, the two sets of data cannot be combined to identify misplaced blocks of fuel. In the utility sector, the Federal Power Commission publishes monthly reports[3] of fuel deliveries, broken down by Region and State, which include the sulfur content. These reports do not give information on the plant size. The Federal Power Commission also releases lists of fuel deliveries to specific plants which include sulfur content. These would have to be totaled over an entire year which would require an inordinate amount of time. Twelve-month summaries of these data are available but, in the aggregation of the data, the plant specificity is last and the resultant average sulfur content cannot be used to represent all shipments.

The National Emissions Data System

One data source which does include all of the required information is the National Emission Data System (NEDS) being developed by EPA. This data source is not complete, however, it contains all of the required information relative to individual sources in a form which could be readily used to identify misplaced blocks of fuel. Some variation exists within the data file with respect to the date of receipt of data. However, the data generally refer to the year 1972.

A tape of the NEDS point-source data file was obtained and a program was written to aggretate the data by sector, source size, EPA region, fuel type, and sulfur content.

Results of the Analysis of the NEDS Data

The regional fuel-use values for the electrical sector first obtained by aggregating the NEDS data were compared with FPC summary data. Three results were obviously too high by an order of magnitude. The program was rerun with screening instructions for the computer to print out the input data on any source for which a heat input of >200 x 10^{12} Btu/year was indicated. Four sources were screened out on this basis. The errors in each case resulted from improper use of units in the input data. The data for each source were recalculated by hand and the resultant corrections applied to the aggregate totals obtained in the first run. With these corrections, the results agreed favorably with the FPC summary data.

The corrected results of data aggregation are presented in Table 2. The data represent aggregate plant fuel consumption in 10^{12} Btu/year. Summaries by sector of the data from Table 2 are given in Tables 3, 4, and 5. It should be noted that the residential sector is not included in the point-source category of the NEDS data file. This is not significant since, as noted previously, the fuels used in the residential sector are generally correctly placed. The percentages of high- and low-sulfur fuel in each plant-size category and the total capacity for each fuel are given in Tables 3, 4 and 5. The total capacity for each fuel in the electrical and industrial sectors may be compared with the actual fuel use, as shown in Table 6, to estimate the completeness of the NEDS data file. This is shown in the following tabulation of the ratio of NEDS total fuel-use figure (Tables 3 and 4) divided by the actual use (Table 6).

Sector	Coal	Petroluem	Natural Gas
Industrial	0.29	0.19	.20
Electrical	1.04	0.90	0.96

The results indicate that for the electrical sector the NEDS data file is reasonably complete. The NEDS data file is much less complete for the

TABLE 2. AGGREGATED DATA FROM NEDS POINT SOURCE DATA BANK. FUEL CONSUMPTION BY SECTOR, SOURCE SIZE, REGION, FUEL TYPE, AND SULFUR CONTENT

Sources ≥ 250x10^6 Btu/hour

Coal, 10^{12} Btu/year

EPA REGION(a)	< 1% S E(b)	I	C/I	TOTAL	≥1% S E	I	C/I	TOTAL	GRAND TOTAL
1	0	0	0	0	60	0	0	60	
2	197	0	0	197	1,063	72	0	1,135	
3	9	72	0	81	2,329	168	0	2,497	
4	73	3	0	76	602	27	2	631	
5	465	9	0	474	987	78	0	1,065	
6	143	29	0	172	1,113	51	0	1,164	
7	567	3	0	570	0	0	0	0	
8	0	0	0	0	0	0	0	0	
Totals	1,454	116		1,570	6,154	396	2	6,552	8,122

Residual Oil, 10^{12} Btu/year

EPA REGION(a)	< 1% S E	I	C/I	TOTAL	≥1% S E	I	C/I	TOTAL	GRAND TOTAL
1	128	0	0	128	266	19	0	285	
2	553	19	16	588	193	32	0	225	
3	129	8	0	137	30	39	0	69	
4	1	0	0	1	3	11	0	14	
5	179	18	0	197	590	105	0	695	
6	76	5	0	81	10	0	0	10	
7	1	15	0	16	8	0	0	8	
8	181	26	0	207	15	4	6	25	
Totals	1,248	91	16	1,355	1,115	210	6	1,331	2,686

Distillate Oil, 10^{12} Btu/year

EPA REGION(a)	E	I	C/I	TOTAL	GRAND TOTAL
1	0	0	0	0	
2	15	5	0	20	
3	10	88	0	98	
4	0	0	0	0	
5	29	5	2	36	
6	14	3	0	17	
7	5	0	0	5	
8	0	4	0	4	
Totals	73	105	2	180	180

Natural Gas, 10^{12} Btu/year

EPA REGION(a)	E	I	C/I	TOTAL	GRAND TOTAL
1	6	0	0	6	
2	108	53	18	179	
3	152	166	57	375	
4	286	106	12	404	
5	329	26	0	355	
6	1,948	560	3	2,511	
7	177	43	2	222	
8	568	139	0	707	
Totals	3,574	1,093	92	4,759	4,759

Sources < 250x10^6 Btu/hour

Coal, 10^{12} Btu/year

REGION	< 1% S E	I	C/I	TOTAL	1% ≤ S < 2% E	I	C/I	TOTAL	≥ 2% S E	I	C/I	TOTAL	GRAND TOTAL
1	0	0	0	0	2	0	0	2	2	1	0	3	
2	26	26	3	55	69	41	2	112	35	47	0	82	
3	17	105	7	129	47	62	4	113	204	231	26	461	
4	17	12	2	31	7	6	0	13	38	21	0	59	
5	14	40	5	59	30	24	3	57	8	2	0	10	
6	0	43	2	45	1	8	0	9	7	30	0	37	
7	13	11	1	25	0	0	0	0	0	0	0	0	
8	0	0	0	0	0	0	0	0	0	0	0	0	
Totals	87	237	20	344	156	141	9	306	294	332	26	652	1,302

Residual Oil, 10^{12} Btu/year

REGION	< 1% S E	I	C/I	TOTAL	≥1% S E	I	C/I	TOTAL	GRAND TOTAL
1	53	25	3	81	65	124	26	215	
2	133	103	14	250	3	33	16	52	
3	7	34	1	42	7	53	1	61	
4	2	3	0	5	2	11	4	17	
5	9	39	17	65	28	121	8	157	
6	2	4	0	6	0	5	0	5	
7	1	4	0	5	0	8	0	8	
8	16	8	0	24	9	9	0	18	
Totals	223	220	35	478	114	364	55	533	1,011

Distillate Oil, 10^{12} Btu/year

REGION	E	I	C/I	TOTAL	GRAND TOTAL
1	1	1	1	3	
2	17	9	7	33	
3	7	27	3	37	
4	1	6	3	10	
5	7	18	3	28	
6	2	9	0	11	
7	1	1	2	4	
8	0	7	0	7	
Totals	36	78	19	133	133

Natural Gas, 10^{12} Btu/year

REGION	E	I	C/I	TOTAL	GRAND TOTAL
1	5	8	1	14	
2	12	52	8	72	
3	74	282	9	365	
4	101	116	18	235	
5	27	154	11	192	
6	133	261	8	402	
7	38	82	6	126	
8	62	56	0	118	
Totals	452	1011	61	1524	1,524

(a) 1 New England
2 North Atlantic
3 East North Central
4 West North Central
5 South Atlantic
6 South Central
7 Mountain
8 Pacific

(b) E Electrical
I Industrial
C/I Commercial/Institutional

TABLE 3. ELECTRICAL SECTOR SUMMARY - NEDS POINT SOURCE DATA

Fuel	Sources >250x10^6 Btu/hr: Fuel Use 10^{12} Btu/year	% of Total	Sources $\leq$250x10^6 Btu/hr: Fuel Use 10^{12} Btu/year	% of Total	Total
Coal					
<1%S	1,454	19.1	87	16.2	1,541
$\geq$1%S	6,154	80.9	450	83.8	6,604
Total Coal	7,608	100	537	100	8,145
Petroleum					
Resid					
<1%S	1,248	51.2	223	59.8	1,471
$\geq$1%S	1,115	45.8	114	30.5	1,229
Distillate	73	3.0	36	9.7	109
Total Petroleum	2,436	100	373	100	2,809
Natural Gas	3,574		452		4,026

TABLE 4. INDUSTRIAL SECTOR SUMMARY - NEDS POINT SOURCE DATA

Fuel	Sources >250x10^6 Btu/hr Fuel Use 10^{12} Btu/year	% of Total	Sources ≤250x10^6 Btu/hr Fuel Use 10^{12} Btu/year	% of Total	Total
Coal					
<1%S	116	22.7	237	33.4	353
≥1%S	396	77.3	473	66.6	869
Total Coal	512	100	710	100	1222
Petroleum					
Resid					
<1%S	91	21.9	220	33.2	311
≥1%S	210	50.5	364	55.0	574
Distillate	105	27.6	78	11.8	183
Total Petroleum	406	100	662	100	1068
Natural Gas	1093		1011		2104

TABLE 5. COMMERCIAL/INSTITUTIONAL SECTOR SUMMARY - NEDS POINT SOURCE DATA

Fuel	Sources $>250 \times 10^6$ Btu/hr		Sources $\leq 250 \times 10^6$ Btu/hr		Total
	Fuel Use 10^{12} Btu/year	% of Total	Fuel Use 10^{12} Btu/year	% of Total	
Coal					
<1%S	0	-	20	36.4	20
≥1%S	2	100	35	63.6	37
Total Coal	2	100	55	100	57
Petroleum					
Resid					
<1%S	16	66.7	35	32.1	51
≥1%S	6	25.0	55	50.5	61
Distillate	2	8.3	19	17.4	21
Total Petroleum	24	100	109	100	133
Natural Gas	92		61		153

TABLE 6. ACTUAL FUEL USE IN 1972 BY CONSUMING SECTOR[a]

Sector	10^{12} Btu/year			
	Coal	Petroleum	Natural Gas	Total Fossil Fuel
Residential and commercial	387	6,667	7,642	14,696
Industrial	4,267	5,668	10,591	20,526
Electric Generation	7,837	3,134	4,102	15,073

(a) Source: Department of Interior/Bureau of Mines News Release, March 13, 1974. Also presented in Project Independence Report, Federal Energy Administration, Appendix A1, p 31 (November 1974).

industrial sector. Fuel use equivalent to only 19 to 29 percent of the actual fuel use is included in the source data file. The commercial/institutional sources are less well represented. As shown in Table 5, a total use for all fuels of only 343 x 10^{12} Btu/year is included in the NEDS file. This is only 6 percent of the total direct fuel consumption in the commercial sector in 1968 shown in Table 1.

Discussion of the NEDS Results

The data assembled from the NEDS file were compared with other information to see that the indicated patterns are reasonable. The electrical sector data given in Table 3 show that, for all fuels, 9.1 percent of the indicated capacity is in the small source category. For comparison, the distribution of steam-electric plants according to size was determined for 1972.(4) The list included 966 plants. Of this total, 15.6 percent were below 25 MW, 11.8 percent were between 25 and 49.9 MW, and 72.6 percent were 50 MW or larger. A more detailed distribution is given in the following tabulation:

Plant Size, MW	Number of Plants	Percent of Total
0 - 19.9	113	11.7
20 - 24.9	38	3.9
25 - 29.9	25	2.6
30 - 34.9	35	3.9
35 - 39.9	18	1.9
40 - 44.9	26	2.7
45 - 44.9	10	1.0
≥50	701	72.6
Total	966	100

The NEDS percentage of small plants appears reasonable in comparison with this distribution, since very large plants would weight the ratio when calculated on a total Btu basis, as was the NEDS percentage, rather than on the basis of the number of plants. A comparison of the NEDS ratio of high- and low-sulfur coal in the industrial sector also was made. Bureau of Mines data for 1972[5] on bituminous coal and lignite shipments, representing about 60 percent of the total coal production, show that about 78 percent of the coal shipped to industrial users (other than coke plants) and to retail dealers was high-sulfur coal. This compares well with the overall value of 71 percent high-sulfur coal in the industrial sector from the NEDS data shown in Table 4. Such comparisons indicate that, although the NEDS data file is incomplete, the indicated fuel-use distributions are reasonable.

The regional location of misplaced blocks of fuel can be seen in the data of Table 2. A summary of the largest blocks is given in the following tabulation:

Fuel	Source Size	Region	Sector	NEDS Quantity 10^{12} Btu/year
Natural Gas	Large	South Central	Electrical	1948
Natural Gas	Large	Pacific	Electrical	568
Low-Sulfur Coal	Large	Mountain	Electrical	567
Natural Gas	Large	South Central	Industrial	560
Low-Sulfur Resid	Large	North Atlantic	Electrical	553
Low-Sulfur Coal	Large	South Atlantic	Electrical	465
Natural Gas	Large	South Atlantic	Electrical	329
Natural Gas	Large	West North Central	Electrical	286
High-Sulfur Coal	Small	East North Central	Industrial	231
High-Sulfur Coal	Small	East North Central	Electrical	204
Low-Sulfur Coal	Large	North Atlantic	Electrical	197
Low-Sulfur Resid	Large	Pacific	Electrical	181
Low-Sulfur Resid	Large	South Atlantic	Electrical	179
Natural Gas	Large	Mountain	Electrical	177
Natural Gas	Large	East North Central	Industrial	166
Natural Gas	Large	East North Central	Electrical	152

Other misplaced blocks of smaller magnitude also are included in Table 2. The blocks listed above are mostly in the electrical sector. This is undoubtedly biased by the fact that, as noted previously, only about

19 to 29 percent of the actual industrial-fuel use is included in the NEDS data file. If that sector were more fully represented, additional blocks of industrial fuel use such as: natural gas in the Pacific and West North Central region, distillate oil in the East North Central region, and low-sulfur coal in the East North Central region, would very likely equal many of the utility fuel blocks listed above.

Extrapolation of the NEDS Data

The distribution of fuel use by region, sector, source size, fuel type and sulfur content appears reasonable and therefore useful in evaluating the possibilities for fuel switching. Also the quantities of fuel indicated in the electrical sector blocks are approximately correct since the total of such blocks approximately equals the actual total for that sector. However, it was noted previously that the NEDS file is incomplete for the industrial and commercial/institutional sectors, therefore, the quantities of fuel in those blocks are too low. In order to estimate the magnitude of those blocks, it was assumed that the distribution of fuel use exhibited by the existing NEDS data would apply to the entire population of sources. With this assumption the summary NEDS data of Tables 3, 4 and 5 were extrapolated on a proportional basis so that the totals for each fuel equal the actual-use values for 1972 as given in Table 6. For illustration, the extrapolated coal quantities in the electrical sector blocks were calculated as follows (all units are 10^{12} Btu/year):

Total actual coal in the electrical sector (Table 6)	= 7837
Total NEDS coal in the electrical sector (Table 3)	= 8145
Ratio = 7837/8145	= 0.96

From Table 3:

Block	NEDS Value x 0.96 =	Extrapolated Value
Low Sulfur, Large Source	1454	1399
High Sulfur, Large Source	6154	5921
Low Sulfur, Small Source	87	84
High Sulfur, Small Source	450	433
Totals	8145	7837

The results of these extrapolations are given in Table 7. The totals for each fuel shown in the last four columns are the same as in Table 6. The residential/commercial sector required slightly different treatment as the NEDS point-source data do not include the residential sector. The totals for each fuel were first allocated separately to the two sectors on the basis of the ratios of fuel use taken from Table 1, in which the two sectors are listed separately. For example, the total natural gas in the R/C sector from Table 6 is 7642 x 10^{12} Btu/year. From Table 1, the residential natural gas is 4606, the commercial natural gas is 1845, and the total is 6451. The residential natural gas allocation is: 7642/6451 x 4606 = 5456, the commercial natural gas allocation is: 7652/6451 x 1845 = 2186, and the total is 7642. The other fuels were allocated in the same manner. This breakdown between the two sectors is given in the second and third lines of Table 7. The natural gas and petroleum quantities for the residential sector were placed directly in the small-source blocks of natural gas and distillate. The fuels in the commercial sector were allocated to each block according to the NEDS distribution (Table 5) in the same manner as for the industrial and electrical sectors. As noted, the extrapolations in the commercial sector are weak because of the limited NEDS data for the sector.

The blocks of misplaced fuels are noted in Table 7 by underlining. On the basis of this extrapolation from the NEDS data, the largest single block is natural gas in large sources in the industrial sector. This is used for process steam and for direct heat. Other

TABLE 7. TOTAL 1972 FOSSIL FUEL USE ALLOCATED BY SECTOR, BY SOURCE SIZE, BY FUEL, AND BY SULFUR CONTENT, ON THE BASIS OF THE NEDS DISTRIBUTION, 10^{12} Btu/year

	Sources $>250\times10^6$ Btu/hr						Sources $\leq250\times10^6$ Btu/hr						Totals			
	Coal		Resid			Natural	Coal		Resid			Natural			Natural	Grand
Sector	<1%S	≥1%S	<1%S	≥1%S	Distillate	Gas	<1%S	≥1%S	<1%S	≥1%S	Distillate	Gas	Coal	Petroleum	Gas	Total
Residential and Commercial													387	6,667	7,642	14,696
Residential											3234	5456	0	3,234	5,456	
Commercial	0*	14*	413*	155*	52*	1314*	136*	238*	903*	1420*	490*	872*	387	3,433	2,186	
Industrial	405	1383	483	1114	557	5502	828	1652	1168	1932	414	5089	4267	5,668	10,591	20,526
Electrical Generation	1399	5921	1392	1244	81	3641	84	433	249	127	40	461	7837	3,134	4,102	15,073

*Weak extrapolation because of limited NEDS data in the Commercial/Institutional category.

large blocks include: natural gas, low-sulfur coal, and low sulfur residual oil in large electric power stations, and high-sulfur coal and high-sulfur residual oil in small industrial sources. The total of misplaced blocks is 21,041 x 10^{12} Btu/year and the total of all blocks is 50,295 x 10^{12} Btu/year. Thus, 42 percent of the total fuel is misplaced. Of the misplaced fuel, 15,239 x 10^{12} Btu/year, or 72 percent, is clean fuel in large sources, while 5,802 x 10^{12} Btu/year, or 28 percent, is high-sulfur fuel in small sources. Thirty eight percent of the clean fuel now burned in large sources would be sufficient to displace the dirty fuel in small sources if it could be switched.

The estimation of the quantities and locations of misplaced fuels for future years is very difficult because of the existance of unpredictable factors which will impact on this situation. Some of these factors are:

- Increasing overall demand will tend to increase the size of the misplaced blocks
- Environmental considerations will tend to increase the use of clean fuels to the extent they are available
- Clean fuels will not be sufficiently plentiful to satisfy all the demand. Even now natural gas supplies to industrial customers are being curtailed
- Synthetic clean fuels will provide some of the demand but projections of the availability of such fuels vary widely according to the source.

In the absence of other considerations, the increase in overall demand would be expected to result in an increase in the size of the blocks of misplaced fuel to the extent that historical fuel sources continue to be utilized. Projections of the rate of growth in overall energy demand vary from a low of 2.7 percent(6) to a high of 4.2 percent(7). A somewhat more modest upper value of 3.7 percent growth was projected by the Department of the Interior(8). Assuming similiar rates of increase in the size of the blocks of misplaced fuel, the projected quantities would be:

Year	Clean Fuels, Large Sources	Dirty Fuels, Small Sources	Total
	10^{12} Btu/year at 2.7 percent growth rate		
1972	15,200	5,800	21,000
1980	18,900	7,200	26,100
1990	24,600	9,400	34,000
2000	32,100	12,200	43,300
	10^{12} Btu/year at 3.7 percent growth rate		
1972	15,200	5,800	21,000
1980	20,400	7,800	28,200
1990	29,300	11,200	40,500
2000	42,100	16,000	58,100

Counter to this tendency for the quantities of misplaced fuel to increase as overall demand increases, is the fact that supplies of clean fuel are limited. The use of natural gas in large boilers cannot increase at the rates suggested above without some dramatic increase in the supply of natural gas.

It is not possible to make accurate projections of future quantities of misplaced fuels because of such conflicting influences. Without definitive action to the contrary, the quantities of misplaced fuels can be expected to increase but at a lesser rate than overall demand.

FACTORS AFFECTING THE ABILITY TO SWITCH "MISPLACED" FUELS

The analysis described in the preceding section has shown that there is a large quantity of clean fuel being burned in large sources and a smaller, but still significant, quantity of high-sulfur fuel being burned in small sources. To achieve the optimum effectiveness with respect to limitation of sulfur oxide emissions, these misplaced fuels should be switched to the extent possible. However, these are constraints which prevent fuel switching in some cases.

The physical form and composition of different fuels varies and, therefore, the equipment requirments for use of different fuels also vary. These equipment requirements may prevent the free exchange of fuel type. Business-related factors may also limit the ability to change fuels. If a plant has long-term contracts for a certain type of fuel which cannot be abrogated, it would be difficult to switch to a different fuel. Finally, the capability of the fuel transportation network to carry fuels in a significantly different pattern and volume may limit the real opportunities for switching fuels.

The nature of the limitations posed by these factors and the degree to which they limit the flexibility in fuel-use patterns are analyzed in the following sections.

EQUIPMENT CONSTRAINTS TO FUEL SWITCHING

In any consideration of switching or interchanging of fuels among various users to promote the lowering of pollution, the ability to alter available equipment to permit such changes must be considered. The purpose of this phase of the study is to define the equipment-related factors that would prevent arbitrary interchangeability or shifting of fuels to reduce overall pollution originating from fuel sulfur content. In general, it is hypothesized that such pollution reduction may be accomplished by shifting the "dirtier" fuels to the larger installations where sulfur clean-up methods are relatively less costly, and feed "clean" fuels to the smaller installations. Thus, one must consider not only barriers to using high sulfur fuels in larger facilities where more control of pollution may be economically possible but also barriers to use of low-sulfur fuels in smaller facilities also involved in any fuel exchange considerations.

In general, gas and fuel oil can be used to replace coal, and gas to replace fuel oil, without too much difficulty. Further, the lighter fuel oils, being of low viscosity, can ordinarily be substituted without difficulty for heavier fuel oils. In the case of coal, there is such a wide variety of coal properties, ash properties and contaminants, that the type of firing system must also be evaluated in considering even the interchangeability of various types of coal. As a result, we are not surprised to find that the recently publicized conversions on the East Coast from fuel oil to coal are all for steam-power plants that were originally designed for coal, and were previously converted to oil.

In this phase of the study, conceptually possible interchanges among natural gas,* oil, and coal will be considered first. This will be followed by a review of the performance problems involved in fuel switching, a general characterization of various boiler types and auxiliary equipment as related to the interchangeability problem, and a discussion of coal interchangeability. A specific example of an oil-to-coal conversion, and the population of possible conversions are next covered. Finally, pertinent conclusions are drawn.

*Possible interchanges involving the installation and use of gas producers will not be considered.

Conceptually Possible Fuel Interchanges

The physical forms of fuels--gaseous, liquid, or solid--require different handling methods and storage facilities, but basically all fuels burned today in large central-station steam-generating power plants are "fluid" fuels when they enter the boiler furnace. For natural gas this poses minimum problems, mainly in metering and distributing the fuel to a plurality of burners. For residual fuel oil, the problems are similar except that the temperature of the fuel must be controlled to compensate for differences in viscosity, and the burners are more complicated. For pulverized coal,* mixing with air produces a "fluid" fuel that calls for burners of even more complexity than with fuel oil.

For industrial and commercial sizes of boilers, similar remarks can be made except for the case of coal. For boilers producing less than 100,000 lb/hr of steam, pulverized fuel is rarely used, and the less common cyclone furnace is not available. Spreader stokers (which compete with pulverized coal in sizes up to 400,000 lb/hr of steam), overfeed stokers, and underfeed stokers are preferred in turn as the capacity decreases. Burning a solid fuel in fixed fuel beds, as on stokers, is different than firing a "fluid fuel" as discussed above, and necessitates some differences in boiler design.

Based on these remarks, the conceptual possibilities for fuel interchange to reduce sulfur oxides pollution can now be tabulated.

TABLE 8. POSSIBLE INTERCHANGES OF FUELS IN BOILER FURNACES

Low Sulfur Fuel	High Sulfur Fuel
Gas	Oil
Gas	Coal
Oil	Coal
Oil	Oil
Coal	Coal

*Pulverized so that 80 percent of the coal particles are smaller than 74 micrometers (200 mesh).

It should be noted that each change to high sulfur fuel in a larger installation implies a change to a low sulfur fuel in a smaller installation. As a result, the characteristics of smaller boiler furnaces that might limit interchangeability, as well as those of larger boiler furnaces, must be considered. Furthermore, other properties are important that might accompany changes in the sulfur context of a liquid or solid fuel, and might have an effect on fuels acceptability with a given design of boiler furnace.

Performance Problems of Fuel Switching

Four main problem areas can be defined in attempting the interchange of fuels in boiler furnaces as suggested in Table 8:

(1) Differences in heat liberation rates selected originally when designing a furnace for a specific fuel;

(2) Differences in the heat-transfer patterns to furnace wall tubes resulting from burning fuels with differing flame characteristics;

(3) Fouling* of heat-transfer surfaces because of the nature of the inorganic matter in some fuels; and

(4) Slagging** problems induced by low-fusion ash in furnaces designed for dry-bottom operation, or difficulty in maintaining fluid slag in wet-bottom furnaces burning coal with high-ash-fusion characteristics.

Heat-liberation rates in central-station boiler furnaces reported by one manufacturer vary over a large range of values: up to 35,000 Btu/ft^3 hr for tangentially fired pulverized coal units; from 20,000 to 30,000 Btu/ft^3 hr for other pulverized coal units and spreader stoker units; and up to 45,000 Btu/ft^3 hr for oil-fired units and natural-gas-fired

* Fouling is deposition of ash on boiler tube banks, usually followed by sintering, with eventual plugging of space between tube banks.

**Slagging is melting of ash deposits in a boiler furnace.

units.[8,9] Another boiler builder indicates ranges of 25,000 to 35,000 Btu/ft^3 hr for oil- and gas-fired units with no essential difference between these fuels and 12,000 to 20,000 Btu/ft^3 hr for dry-bottom pulverized coal furnaces. Values for wet-bottom are somewhat greater. The curves shown in Figure 1 indicate that, for a given furnace-exit-gas temperature, the oil-fired unit would be smallest in surface area and the pulverized coal unit the largest.

One may conclude, therefore, that for the same total rate of energy release, furnaces for coal firing are larger by 1.5 to 2 times than gas or oil-fired units. Thus, ignoring the ash problem, substituting coal for oil or gas would reduce the rating of a furnace up to one half.

Differences in heat-transfer patterns between gas, oil, pulverized coal, and stoker coal because of the differing flame characteristics of these fuels, can be compensated in large part by skillful design of the burners. Advances in the state of the art of controlling flame configurations over the past 20 years make this the easiest problem to surmount in substituting one fuel for another.

Fouling of heat-transfer surfaces with the mineral matter in "dirty" fuels is a major problem in substituting coal for oil or gas. In a furnace designed to fire coal, multiple sets of soot blowers are installed, as shown in Figure 2. However, because no such fouling occurs with natural gas, and is minimal with some fuel oils, no allowance is made for ineffective heat-transfer surfaces in these furnaces as is necessary in coal-fired units. Hence, coal cannot be substituted for oil or gas without a significant penalty in rating. Further, since slag deposits on furnace walls when burning coal raise the temperature of the flue gas reaching the superheaters, simply because the wall tubes cannot then abstract thermal energy from furnace gases, the unit must be derated to limit outlet steam temperature or elaborate systems must be provided to bypass the superheater to keep steam temperatures within design limits.

Slagging problems are troublesome also in substituting one coal for another. High-sulfur coals, for example, almost always contain large amounts of pyrites, FeS_2, which converts to FeO or Fe_2O_3 as the coal is burned. These iron compounds are extremely effective fluxes for

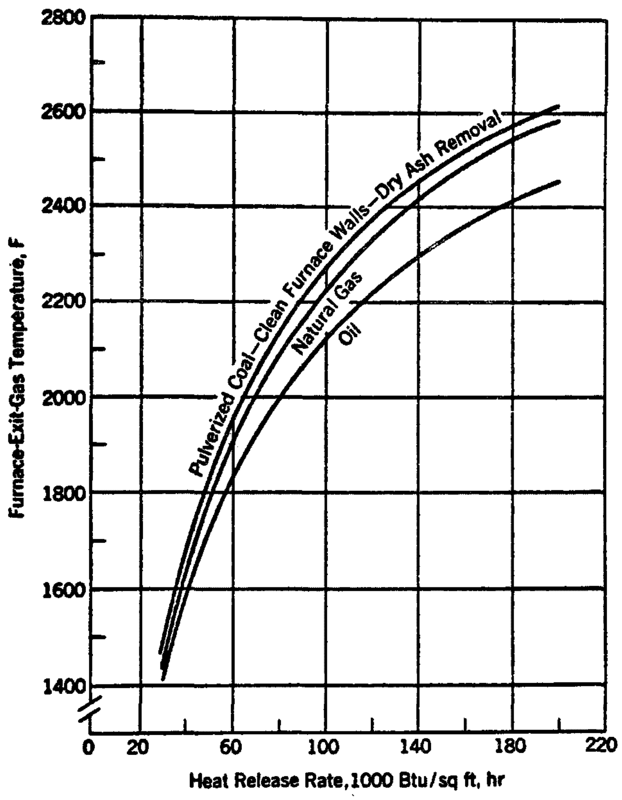

FIGURE 1. APPROXIMATE RELATIONSHIPS OF FURNACE-EXIT-GAS TEMPERATURE TO HEAT RELEASE RATE FOR VARIOUS FUELS

Source: "Steam, Its Generation and Use", Babcock & Wilcox, 1972

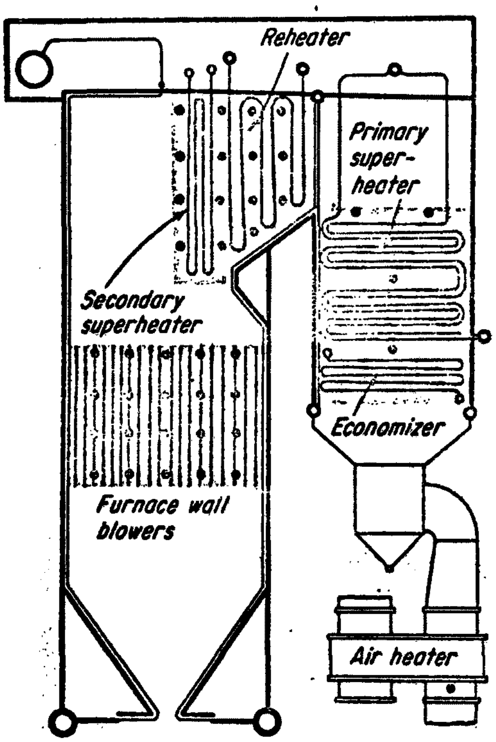

FIGURE 2. STEAM GENERATING SYSTEM SHOWING TYPICAL LOCATION OF SOOT BLOWERS

Source: Bender, R. J., "Steam Generation" Power Special Report, McGraw-Hill (No date) decreasing the fusion temperature of coal ash so that high-pyrite coals almost invariably melt at low temperatures and are easily slagged. Low-sulfur coals, contrarywise, contain small amounts of pyrites and, hence, do not generally melt as easily, at least for Eastern coals. Western coals, on the other hand, although low in pyrites, often contain large amounts of CaO, MgO, and Na_2O which also are effective fluxes and lead to low melting points. Therefore, although sulfur content is a fair indicator of ash-slagging tendency for Eastern coals, it is not equally predictive for Western coals.

It is possible to add flux such as limestone to coal to induce the formation of molten slag for slag-tap furnaces. The utilities have been reluctant to use this approach because of the possible formation of molten iron in the slag bed and of increased fouling of superheaters.

Preventing the formation of slag is much more difficult; no practical scheme has been demonstrated as yet whereby a low fusion coal can be burned satisfactorily in a dry-bottom furnace at any reasonable heat release rate.

Boiler and Auxiliary Equipment

Boiler furnaces do not differ radically in design for different fuels except in provisions for differing ash characteristics. Natural gas has no problems here. Thus, boilers to be fired only with natural gas need no provision for preventing ash deposits, or for ash handling.

Residual fuel oil contains up to 0.1 percent inorganic matter (ash), for which allowance must be made in boiler design because of the deposits that gradually accumulate on heat-receiving surfaces. While the small amount of ash may have little effect on heat transfer, the highly corrosive nature of the deposits on heat-receiving surfaces when burning fuel oils high in vanadium and sodium poses special problems. European utilities often surmount this problem by operating with very low excess air, typically less than 1 percent, but this practice is not followed generally in the United States.

Oil-fired furnaces are often equipped to burn natural gas since furnace design characteristics do not differ significantly for these two fuels. In fact, for smaller capacities, below about 10^5 lb/hr of steam, design of gas- and oil-fired units are often identical. Nevertheless, since there is an appreciable difference in the radiation characteristics of oil flames compared with gas flames, the transfer of heat to the furnace walls may occur in quite different patterns. This means that provisions must be made in larger-capacity boiler furnaces, either oil or gas, for bypassing some of the furnace outlet gas around the superheater to control steam temperature within the narrow limits required by modern steam turbines. Generally, though, natural gas or fuel oil can be burned interchangeably in most large boiler furnaces designed originally with heat-transfer surfaces intended for these "clean" fuels. The major exception is when "corrosive" fuels are used.

Coal-fired boiler furnaces, especially when pulverized coal is used, do not differ greatly in general design from gas-fired or oil-fired units. However, as also mentioned above, the size is generally larger for a given capacity, unless it is a multiple fuel unit; in this case, the needs of the coal-firing system control the size rather than gas firing or oil firing. Because of the severe fouling of furnace wall tubes, superheater and reheater elements, economizers, and air preheaters, passages must be made larger with coal firing than with a comparable oil-fired or gas-fired unit. Furthermore, provision must be made for extensive soot blowing of the passages (see Figure 2).

In the utility-size range, pulverized coal-fired units are by far the most common. The burners are similar to gas or oil-fired burners, and thus the boiler configuration in this extent is similar. However, because of the difference of slagging characteristics of various coals, dry bottom and wet bottom (or slag tap) configurations are available. This imposes an extra feature on the coal-fired boiler. In the case of the cyclone furnace, the primary burning takes place in the "cyclone" or "cyclones" exterior to the boiler, and again an extra feature is superimposed on the boiler.

In the smaller utility boiler range and the industrial boiler range of coal-fired units, fuel-burning equipment varies widely. Stoker firing predominates, with pulverized coal being little used in the size range below 100,000 pounds of steam per hour. Cyclone furnaces likewise are not common, and are not available below 100,000 lb/hr of steam. Of the stokers, spreader stokers are most common in the larger units, with underfeed stokers widely used in the range below 100,000 pounds of steam per hour. Overfeed stokers are found in both large and small industrial furnaces, but in relatively small numbers. However, in recent years, the sales of underfeed stokers have been confined almost exclusively to a capacity less than 20,000 lb steam/hr, and overfeed units appear to have taken over the market. Stokers, then, provide the means of burning most coal in industrial furnaces; the configuration of at least the lower part of the boiler must be adapted to the stoker system, in addition to the size provisions made for the lower firing rate per unit volume.

In considering an interchange of fuels, there are differences in the auxiliary equipment that must be considered, in addition to the differences in the gas-fired, oil-fired, and coal-fired boilers themselves. Table 9 lists this equipment.* First, comparing gaseous firing, oil firing, and pulverized coal firing, it is immediately noted that the burners are of different design although they can be designed to handle any two or all three of the fuels. For cyclone furnaces and stoker furnaces, it is clear that completely separate systems are needed for coal as compared to gas and oil. In addition to the changes in burner design, there are a considerable number of other changes required, with an increasing complexity of requirements for gas to oil to coal.

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*References 9 and 10 contain detailed descriptions of the equipment mentioned.

TABLE 9. AUXILIARY EQUIPMENT NEEDS

Auxiliary Equipment	Fuel					Comments
	Gas	Fuel Oil	Coal			
Basic storage	None	Tanks	Open storage			Ravenswood uses barge supply to bunkers
Intermediate storage	None	None	Bunkers and hoppers			
Ash handling	None	Moderate facilities	Large facilities			
Ash disposal	None	Moderate facilities	Large facilities			
Soot blowers	None	Moderate facilities	Large facilities			
Product gas cleanup	None	Moderate facilities	Large facilities			All large size conversion to coal and some to oil will require electrostatic precipitators
Transportation of fuel	Piping	Piping	Conveyor system			
			Pulverized Coal	Cyclone	Stoker	
Preparation of fuel	None	Heating system Additive systems	Pulverizer Dryer	Crusher Dryer	Crusher Dryer	
Transportation of prepared fuel	Piping	Piping (lagging)	Pneumatic transport	Mechanical	Mechanical	
Burner	Gas	Oil, with steam, air, or mechanical atomization	P.C. with pneumatic transport	Cyclone furnace	Grates and distribution system	

NOTE: Ignition system and flame sensor system may require change.

Coal Interchangeability as Related to Firing Method

Fuel-burning equipment varies widely over the range of steam generating capacity. In the utility size, say, over 200,000 lb/hr of steam, pulverized coal firing predominates. There are two subclasses, dry bottom and wet bottom (or slag tap). Cyclone furnaces are also used, and even some spreader-stoker units in sizes up to 400,000 lb/hr of steam. In the large capacity end of the industrial size units, from 100,000 to 500,000 lb/hr of steam, the use of pulverized coal-fired units tends to decrease, and spreader stokers take an appreciable portion of the market. There are some cyclones, and a few overfeed stokers. Between 10,000 and 100,000 lb/hr of steam, spreader stokers predominate. Underfeed stokers are second in older units, but seem to be disappearing from the market. Some pulverized coal units are in this capacity range, but overfeed stokers appear to be taking an increasing percentage of sales. The choice of unit in any of these capacities is determined at least partly by the type of coal used;* if the unit is also fired with a refuse or waste product of some sort, this may be the determining factor in the type of unit used.

In any case, each of the units has certain characteristics that could limit the interchangeability of fuels that might be suggested as a means to decrease overall pollution from sulfur oxides, using a limited supply of fuel. Therefore, each will be discussed in turn after discussing the characteristics of coal.

Coal Characteristics

Composition of Coal. Because "coal" as a generic term usually refers to any of the combustible minerals formed from early plant life, there is a real and significant difference between the various ranks of coal.

*Reference 9 suggested the primary considerations are as follows:
Pulverized-coal firing: grindability, rank, moisture, volatile matter, and ash.
Stoker firing: rank of coal, volatile matter, ash, and ash-softening temperature.
Cyclone-Furnace firing: volatile matter, ash, and ash viscosity.

Peat, brown coal, and lignite at one end of the scale, and anthracite and meta-anthracite at the other demonstrate the obvious variations that exist in combustibility and physical properties of this solid fuel called "coal". But there can be equally significant differences (even in the same rank of coal) that can greatly affect the ability to burn one coal satisfactorily in equipment designed for another coal. For example, variations in caking tendency, ash content and composition, reactivity, and heating value typify the kinds of characteristics that must be considered in substituting one coal for another.

The drive for low-sulfur oxide pollution has led to an increase in use of "Western" coals, which are subbituminous coals and lignites, as a substitute for high-sulfur bituminous coal. However, Western coals generally differ from Eastern coals in heating value, caking tendency, and ash characteristics as well as in sulfur content, and it is such variables as these that must be taken into account when substitutions are being considered. For instance, because Western coals usually have a much lower heating value than Eastern coals, stoker ratings may have to be decreased when burning low-rank Western coals.

Composition of Ash. Coal ash is a heterogeneous substance composing at least a hundred different minerals such as clays, carbonates, and sulfides. The complexity is increased because some of these inorganic materials originally were part of the growing plants that were converted to coal, and others resulted from sedimentation or from mineral-laden waters that percolated through the coal bed. Hence, there is a very great difference between the characteristics of ash from different coals. At one extreme, some coal ashes high in fluxes such as Fe_2O_3, CaO, MgO, and the alkalies may sinter at temperatures as low as 1500 F and form a highly fluid melt at 1800 F. Other coal ashes, essentially containing SiO_2 and Al_2O_3 may not sinter below 2500 F and do not produce a fluid slag even at furnace temperatures as high as 3000 F.

The fusion characteristics of coal ash have been thoroughly investigated, and relationships have been developed between chemical composition and the viscosity of the melt once a coal-ash slag is formed. This relationship, based on the amount of SiO_2 in the slag, is widely used for predicting slag characteristics, but it has only limited usefulness in estimating the temperature where the mineral matter in the coal can accumulate on heat-receiving surfaces to interfere with heat transfer or to plug gas passages.

Storage Characteristics. Stockpiling low-rank coals has posed many problems in the past because of the high reactivity of most low-rank coals. At one time, stockpile fires with subbituminous coal and lignite were regularly expected, particularly if the coal had been dried. Today, that problem is minimal. It is necessary, however, to compact the stockpile more densely than is necessary with less-reactive bituminous coal, but this can be achieved by putting the coal down in thin layers and rolling intensively. Loss of heating value through oxidation in a stockpile is worse with Western coals than Eastern coals, but the loss even over several years of storage is not significant if the coal is handled properly.

Grindability. Grindability is an important property of coal intended for pulverized-coal firing but it has no significance for stoker-fired furnaces. If the Hardgrove grindability of a Western coal is half that of a bituminous coal, which can be the case, then the output of a given size pulverizer also would be about halved. More importantly, probably, will be the moisture content of lignite and some subbituminous coals which will greatly decrease mill capacity. Thus, for pulverized coal-fired furnaces, considerable derating of the plant may be necessary in switching to Western coals.

Slag-Type Furnace (Cyclone and Some Pulverized Coal)

Differences in slagging characteristics have led to dividing pulverized-coal-fired boiler furnaces into two main categories: (2) slag-tap or wet bottom, and (b) dry bottom. In the slag-tap furnace, high heat release rates are provided and furnace temperatures reach 3000 F or more, so that the coal ash is deliberately melted and accumulates as a viscous liquid on the floor or hearth of the furnace from which it drips continuously. Popular in the 1930's and 1940's, such furnaces are not being built today. The "cyclone" furnace, where high-velocity, tangentially added air and crushed coal are burned within a tubular, horizontal furnace still are being widely used although their popularity has waned over the past decade. In these furnaces, a layer of molten slag covers the entire cyclone section area, capturing large particles of coal which burn gradually while most of the coal burns in suspension. Temperatures reach 3100 F in cyclone furnaces.

Western coals contain mineral matter leading to ash with a low fusion temperature. Hence, slagging will be accentuated in pulverized coal-fired units to the point where a dry-bottom furnace operating satisfactorily with a bituminous coal may have to be derated appreciably with many Western coals because of slag formation. Slag-tap furnaces generally would benefit from this substitution. Good techniques exist for evaluating slag viscosity, but these methods have not been entirely successful in predicting the formation of slag deposits that decrease heat transfer to wall tubes.

Serious metal wastage has been experienced for at least 30 years in central-station boiler furnaces burning bituminous coal through the formation of liquid films beneath deposits on wall tubes and superheaters. The causative agent is $Na_3Fe(SO_4)_3$ or the corresponding potassium compound; conditions leading to the formation of these objectionable materials are well understood.

Two conflicting conditions will exist when Western coals are burned: (1) the sodium level probably will be high and (2) the SO_3 will certainly be low. Further, the presence of CaO in the flyash will tend to prevent formation of these objectionable trisulfates. It is likely, then, that external corrosion may not be a serious problem with Western coals unless other factors induced by the high Na_2O content turn up to be significant, as in the formation of alkali pyrosulfates at the lower temperature conditions existing in industrial furnaces.

Dry-Bottom Pulverized Coal Furnaces

In dry-bottom furnaces, heat-release rates generally are lower so that furnace temperatures are less than in slag-tap furnaces, and the heat distribution pattern is adjusted to minimize the formation of ash deposits on heat-receiving surfaces. This is a difficult task with some coals. Large numbers of wall blowers and of superheater "soot" blowers usually are needed to remove deposits as they form, but such cleaning systems sometimes are only marginally effective. Thus, fouling of superheater surfaces is expected to be worse with Western coals than with most bituminous coals. Both CaO and Na_2O lead to the formation of low-melting silicates which tend to bind flyash particles into a coherent layer. Hence, the presence of minerals containing lime and sodium in Western coals may accentuate fouling problems when these coals are burned. As a result, dry-bottom furnaces designed, say, for 800-MW may have to be derated to less than 700 MW if a change is made from Eastern to Western coals, an expensive solution to the problem of matching coal to the furnace in which it is burned.

Concerning metal wastage, the same problems hold here as for slag-tap furnaces.

Spreader Stokers

These stokers depend upon burning a large amount of coal in suspension, the grate being provided for burning the larger particles of coal and for removing ash. (About 50 percent of the coal is burned in suspension.) Coal reactivity affects the rate of burning in suspension, and hence there may be a minor problem in arriving at a satisfactory size consist when the more reactive Western coals are fired. Also, clinkering can be troublesome with spreader stokers, both with sectional dumping grates and with traveling grates in the larger sizes, so that ash characteristics also will be important in coal substitution for these boilers. In general, no major problems are foreseen in burning low-rank Western coals in spreader stokers. However, there may be a problem with auxiliary equipment. A spreader stoker has a maximum heat release rate of about 10^6 Btu/ft^2 hr based on grate area, with most of the burning taking place in suspension. This represents a burning rate of about 77 pounds of 13,000 Btu bituminous coal per hour per square foot of grate area. To achieve the same heat release with subbituminous coal of 9000 Btu heating value, this firing rate would have to be increased to 112 pounds of coal per hour. For 6000 Btu lignite, the firing rate would be 167 pounds per hour, indicating a problem with coal-handling facilities in substituting low-rank coals for bituminous coal. In addition to conveyor and bunker capacity, this could cause troubles in moving this increased quantity of coal through stoker feed mechanisms. The alternative, of course, is derating of the boiler, not a very satisfactory solution in most industrial applications where steam demand is fixed and surplus capacity usually is not available. This problem of stoker rating with low-rank coals will require particular attention.

Similar problems may occur in ash handling capacity as existing boilers may not have sufficient capacity to handle the increased ash quantities associated with a high-ash, low-Btu Western coal.

Overfeed Stokers

Because overfeed stokers have a relatively stagnant fuel bed, they have particular problems burning strongly caking coals. Weakly caking or free-burning coals perform best on these stokers. Also, since temperatures at the grade level can be very high as the downward-moving plane of ignition reaches the grate, clinker formation can be troublesome if ash-fusion temperatures are low. Most Eastern coals have a higher caking index than Western coals; thus the problem of coke formation would be expected to be eased with the Western coals. Clinker formation is unpredictable since it depends on the chemical composition of the inorganic material in the coal. Broadly considered, the high content of CaO and Na_2O in some Western coals will lower their ash fusion temperature, thereby increasing the tendency to form objectionable clinkers that will plug the grate tuyeres, cause grate-bar overheating, and interfere with air flow through the fuel bed. Problems related to the use of lower heating value and to higher ash coals are similar to those considered above for spreader stokers.

Underfeed Stokers

With mechanical agitation of the fuel bed as the coal is fed through the retort of an underfeed stoker, coke formation causes few problems. Hence, underfeed stokers can burn strongly caking coals, one of the reasons why they are used predominately in industrial furnaces rated up to 100,000 pounds of steam per hour. Free-burning Western coals may cause problems in underfeed stokers through loss of fines because of the high air velocity through the stoker tuyeres. Low-ash-fusion coals usually are handled satisfactorily by underfeed stokers, but an excessively fluid clinker can cause problems in plugging of tuyeres. But, in general, Western coals should cause few problems when substituted for bituminous coals in underfeed stokers, except as related to the low heating value, as discussed above.

Specific Example of Conversion

The history of the conversion of 1000 MW Ravenswood Unit 3 to coal from oil illustrates the problems of conversion.[10] The location of this unit, originally designed for coal with oil as the standby fuel, had to be changed, delaying construction. To get the unit on line in the desired time, oil was made the primary fuel. While the oil-fired unit was being erected, the decision was made to convert eventually to coal, for purposes of economy and fuel source reliability. To reduce costs and unit down-time, work was performed in three stages, (1) while the oil-fired unit was being erected, (2) while both furnaces were being operated, and (3) while one furnace was shut down. The changes involved coal handling equipment, ash disposal equipment, boiler, high-temperature precipitator, and forced and induced draft fans. The high-temperature precipitator was installed to overcome the adverse effects of low sulfur fuel on low-temperature precipitators. The change in fans resulted from a decision to change to a balanced draft from forced draft operation.

The point should be emphasized that the original boiler design was for coal firing, so that no downgrading in performance was necessary on reconversion. Nevertheless, a considerable amount of additional provisions had to be made to handle coal firing.

Population of Convertible Utility Boilers

A staff report of the Federal Power Commission,[11] based on the results of a survey covering about 98 percent of the fossil-fuel based electric generating capacity of the U.S. as of the end of 1972, presents a realistic picture of the potential for large shifts in the utilities area from gas firing and from oil firing to coal firing.

The FPC points out that in the period 1965 through 1972, for reasons of economy and antipollution requirements, about 28,800 megawatts nameplate capacity was converted from coal to oil. This was estimated as the equivalent of about 14×10^{14} Btu/year, or the equivalent of 55 percent of the residual oil being burned by electric utilities in 1972. Of this capacity, 79 percent could be reconverted, at a cost of \$4.70/kilowatt (1972). This would be about 44 percent of the total oil-fired steam-utility capacity. About 52 percent of the capacity can be reconverted in three weeks, provided coal of the proper type (similar properties to that previously fired) can be supplied. It is mentioned that by eliminating the use of oil in dual-fired oil-coal fired units, an additional 3-1/2 percent of oil could be diverted.

It was found that only 2,230 megawatts or 11×10^{13} Btu/year was convertible from gas to coal firing, with about 24 percent reconvertible within three weeks. On the other hand, burning only coal in dual fuel coal-gas fired units would save 47×10^{13} Btu/yr.

The reasons for irreversible changes are not enumerated, but several can be suggested. Coal storage areas in some instances have been eliminated and replaced by other construction. In seaboard areas where ash had been disposed of by dropping at sea, this option for disposing of the ash has been removed. In the process of conversion away from coal, or subsequently, soot blowers could have been removed, ducting and piping changed, and interior change made in the boilers. Pulverizer, coal crushers and associated ducting could have been removed and replaced by other construction to increase plant capacity. As a result, a permanent loss of about 20 percent in reconversion is not unexpected.

Conclusions

From a practical standpoint, the replacement of oil or gas by coal in firing utility or industrial boilers must be restricted to those boilers that were either (a) designed for coal and gas and/or oil, or (b) designed for coal and converted to gas and/or oil. In either case, the conversion or reconversion can take from a few weeks up to more than a year, depending on the degree of reconversion necessary and the availability of equipment. In some instances, while conversion or reconversion is technically possible, changes in such factors as space availability, coal availability, or ash disposal means can make conversion impossible.

Replacement of one coal by another also poses problems. Many of the high-sulfur Eastern coals and the low-sulfur Western coals contain effective fluxing materials and do not lend themselves to use in the more common dry-bottom pulverized coal-fired furnaces without derating. Furthermore, the low-sulfur characteristic causes a loss in effectiveness of the common low-temperature electrostatic precipitators. In stoker-fired units, loss in capacity with lower Btu fuels and necessity for increase in crushing capacity appears to be the principal problem that may occur.

In general, the use of a coal other than that for which a steam generating system was designed will result in a decrease in system capacity. In some instances, this can be rectified by suitable changes in or additions to equipment.

BUSINESS-RELATED CONSTRAINTS TO FUEL SWITCHING

Long-term contracts and direct ownership of fuel resources by consumers are two major business factors which may tend to inhibit the switching of "clean" fuels away from large industrial and utility boilers. The true importance of these factors was difficult to fully ascertain because of the short time available for research and because of the proprietary nature of much of the data. However, on the basis of a preliminary investigation the following generalizations can be made:

- The use of long-term (10 years or more) contracts for the purchase of coal by the utilities is important and increasing rapidly. The great bulk of all new contracts for low-sulfur coal from the West are of this type.
- Based on sample data from 43 utilities*, it is estimated that coal under contract by utilities is in excess of 4.2 billion tons. This is a conservative estimate as it is known that many more utilities have signed long-term contracts but data on the magnitude of their commitments could not be determined.
- In the case of industrial users of coal, the situation appears to be quite different. Coal use by industry has been declining for several decades, and those firms still using coal have tended to buy coal on a spot basis or on short-term contracts (of 5 years or less).
- Because of the increasing shortages of natural gas and the high prices for oil, many industrial concerns are considering the conversion to coal. It is predicted that industrial customers will have to sign long-term contracts in order to obtain coal in the future.
- Captive coal operations by utilities produced about 32 million tons of coal in 1973, which was equivalent to 9 percent of the total coal used by utilities in that year.

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* See Appendix A for list of utilities.

- Utility companies own coal reserves in excess of 6.1 billion tons.
- Non-utility companies, whose primary business is not coal mining, own considerable quantities of coal reserves. However, in most cases their current mining operations are not strictly "captive", but are usually operated as commercial, open market operations.
- Although spot purchases of oil by utilities are less important than in the case of coal, the duration of the contracts for oil tend to be shorter. Only in a few cases, do utilities purchase oil under contracts of 5 years or more duration.
- Data on oil purchases by industry are very sparse, but it appears that the industrial contracts are also of short duration.
- In the case of natural gas, long-term contracts are the rule for both "firm" and "interruptible" gas.
- However, in spite of the long-term contracts for natural gas deliveries to utilities and industrial consumers are below contracted levels. Regulatory agencies have been curtailing deliveries to large users in order to reserve gas for residential customers.

Summary

Long-term contracts do not appear to be a significant barrier to switching of oil and natural gas. Ownership of oil and gas properties by industrial customers and utilities is not well defined, but does not appear to be a significant barrier. However, in the case of coal, utilities have very large tonnages of coal under very long-term contracts as well as owning significant reserves of coal. Captive production of coal accounts for less than 10 percent of current coal needs, but may increase in the future. Industrial coal purchases are mostly short-term contracts and captive operations by nonsteel companies are not significant.

Utility Fuel Purchasing Practices

Coal

Traditionally, coal markets were extremely unstable because of the low concentration among producers and the ease with which producers could enter and leave the industry. In the post-World War II period the demand for coal fell sharply as many markets declined. The large market for coal in the railroad industry essentially disappeared as dieselization of the lines was accomplished. The invasion of natural gas into the commercial, industrial, and retail markets following the extension of pipelines into markets far removed from the gas fields caused these markets for coal to decline as well. Only in the electric utilities markets was coal able to continue to compete and this market now dominates the coal business. Utilities are interested in cheap, reliable energy in large quantities. The coal industry responded by improving productivity, by utilizing unit trains, and by increasing the size of their operations. The use of long-term contracts increased because it was advantageous to both parties, by assuring the coal companies a market for their coal and by assuring utilities of reliable fuel supplies. In face of the threat of competition from nuclear energy and of restrictions on coal use from air pollution regulations, such guarantees were essential to the coal companies in order to justify their investment in new mines. Although some utilities still preferred to buy on the "spot" market or to use mostly short-term contracts to keep their options open, an increasing percentage of the large utilities tended to rely on long-term contracts for the bulk of the coal supply.

It has been estimated that about 40 percent of the coal procured by the utilities in 1969 was bought on long-term (10 years or more) contracts*. In an attempt to obtain more recent data on coal contracts, reports by the Federal Power Commission on monthly fuel purchases by utilities between April, 1973 and June, 1974 were examined. Table 10 indicates the trends in the amounts of coal purchased on "contract" and on "spot" bases. From this it

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* Gordon, Richard L., Department of Mineral Economics, The Pennsylvania State University, unpublished manuscript, "Methods of Fuels Purchasing for Electric Power Generation".

TABLE 10. TRENDS IN COAL PURCHASES BY UTILITIES BETWEEN APRIL 1973, AND JUNE 1974, BY TYPE OF PURCHASE. (a)

Month	Total 1000 Tons	Contract Purchases		Spot Purchases		
		1000 Tons	Average Price (b)	1000 Tons	Percent of Total Purchases	Average Price (b)
April, 1973	30,062.9	24,526.5	38.2	5536.4	18.4	44.3
May	34,124.8	28,251.7	38.5	5873.1	17.2	43.5
June	31,114.3	25,598.9	39.0	5515.4	17.7	44.5
July	29,017.2	23,372.6	38.6	5644.5	19.5	44.5
August	34,870.1	27,928.4	38.6	6941.7	19.9	44.8
September	31,267.1	25,062.8	39.6	6204.3	19.8	45.4
October	33,573.0	26,696.4	40.2	6876.6	20.5	48.2
November	31,193.8	24,658.5	41.7	6535.3	21.0	52.0
December	30,087.9	24,262.5	42.4	5825.3	19.4	58.0
January, 1974	30,388.1	24,109.2	44.9	6278.9	20.7	75.8
February	29,659.8	23,447.6	47.6	6212.2	20.9	90.5
March	35.291.2	27,196.5	48.7	3094.7	27.3	100.0
April	33,603.9	25,957.4	51.6	7646.5	22.8	104.5
May	35,795.3	28,128.1	54.1	7667.2	21.4	107.6
June	36,533.8	24,076.8	54.9	7457.0	23.6	114.8

(a) Source: Federal Power Comission, Monthly Reports on Cost and Quality of Fuels for Steam-Electric Plant, based on FPC Form No. 423.

(b) Cents per million Btu.

can be seen that "spot" purchases as a percent of total coal purchases have increased over the period in question, partly in response to the dislocations in the market brought about by natural gas shortages and by the Arab Oil Embargo. However, "contract" purchases still accounted for 73 to 83 percent of the total coal sales during this period. Figure 3 indicates the importance of "spot" coal purchases by state, based on data for June, 1974. From this figure it can be seen that there is considerable variation geographically in regard to the importance of "spot" purchases of utility coal, with the East Coast states being most dependent on this form.

There is a serious deficiency in the FPC data cited above in that there is no indication as to the duration of the contracts. A 35-year contract is not distinguished from a 1-year contract and such a distinction is important to the purposes of this report. Therefore, it was necessary to examine the FPC data in more detail. The forms upon which the FPC bases its monthly report are reports from individual utility companies and includes information regarding contract length. The Weekly Energy Report publishes these data in a convenient form. Based on a sample of reports for June of 1974, which accounted for 14.6 percent of the total coal purchased in that month, it was found that 32.5 percent was purchased on spot basis, 4.3 percent was purchased under contracts which expired within 24 months, and 62.7 percent was purchased uner "long-term" (more than 24 months in duration) contracts.

Next, in an attempt to quantify how much coal is committed under long-term contracts, the recent prospectuses and registration statements filed with the Securities and Exchange Commission by 43 utility companies in various parts of the country were examined. On the basis of the sample data included in these reports, it was found that a minimum of 4.24 billion tons are under such contracts, a large portion of which is for western low-sulfur coal. Table 11 lists the largest of these commitments made by utilities. The total cited is only a minimum because even for the sample utilities checked the data were incomplete. A random sample of recent issues of Coal Age, Coal News, and the Wall Street Journal turned up an additional 575 million tons of coal under long-term contract. By 1980, Wyoming alone is expected to be exporting 50+ million tons per year to utilities in Arkansas, Nebraska, Oklahoma, Texas, Louisiana, Colorado, Iowa, Missouri, Illinois, Wisconsin, Kansas, and Indiana (Coal Age, May, 1974, 97). In addition, almost 34 million tons

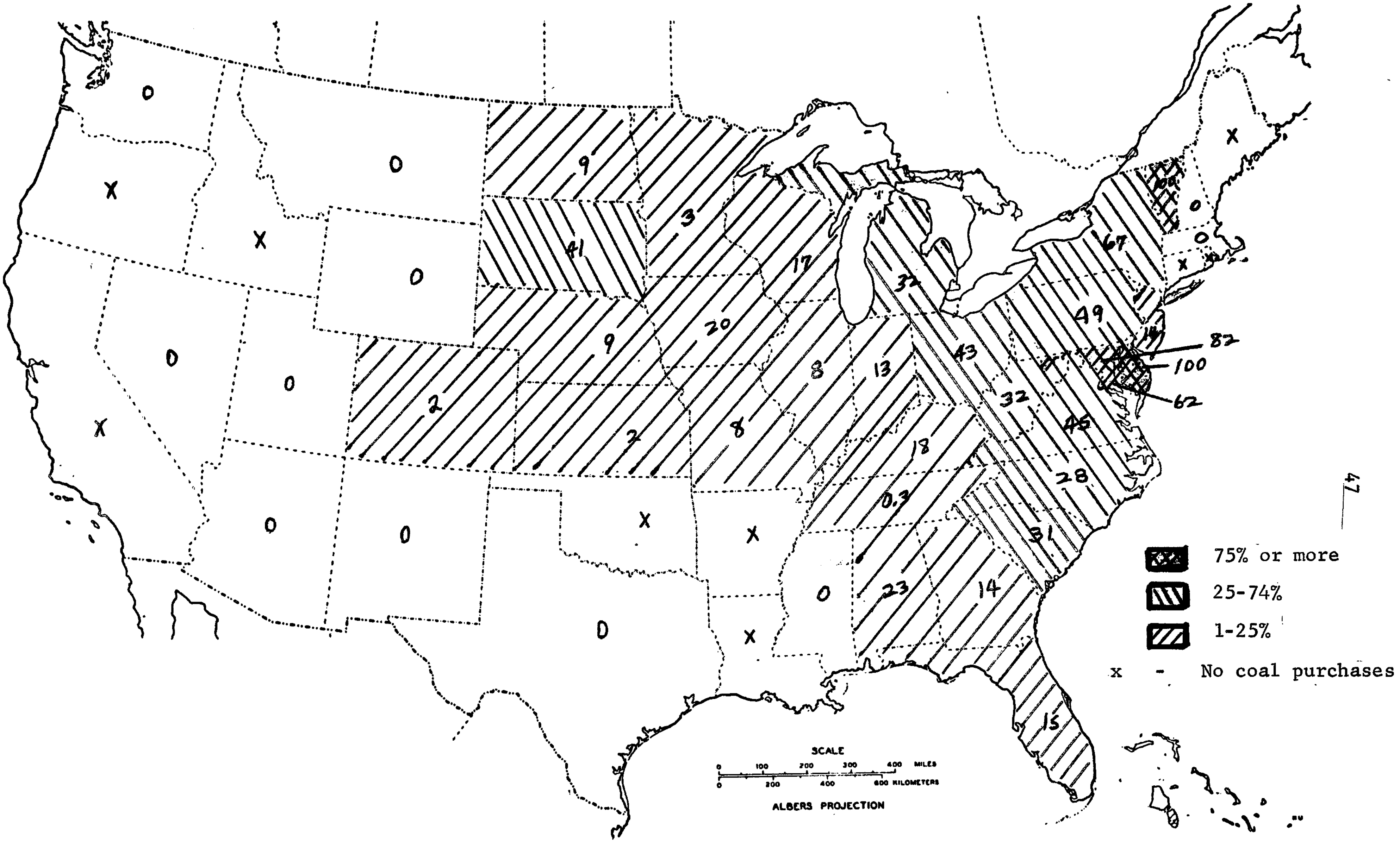

FIGURE 3. SPOT COAL PURCHASES AS PERCENT OF TOTAL COAL PURCHASES BY UTILITIES, JUNE 1974

(Source: FPC)

TABLE 11. LIST OF LARGEST COMMITMENTS OF COAL UNDER LONG-TERM CONTRACT BY SELECTED UTILITIES

	Committed Tonnage (Million t.)
American Electric Power Company	907 (a)
Arkansas Power and Light Company	100 (b)
Cleveland Electric Illuminating Company	180 +
Commonwealth Edison Company	311
Detroit Edison Company	450
Northern States Power Company	181
Pacific Power and Light Company	200
Philadelphia Electric Company	230
Puget Sound Power and Light Company	105
The Southern Company	512
Utah Power and Light Company	224
Wisconsin Power and Light Company	109
	3509

(a) AEP is in advanced negotiations for an additional 210 million tons of Western coal.
(b) Option to purchase 50 million tons additional exists in contract.

Source: Prospectuses and registration statements filed with SEC.

of coal will be burned in Wyoming in that year. It can be assumed that essentially all of this coal will be sold under long-term contracts or is captive coal of the consuming utility. Therefore, it can be seen that the utilities have made a significant long-term commitment to coal. In order to obtain complete data as to total coal committed under long-term contracts would require a canvass of the coal companies and utilities. Time for such a canvass was not available.

A second business factor affecting the switching of fuel is vertical integration into the coal business by means of captive coal mining operations. Table 12 lists the various capitve coal mines known to be operated by utilities. From this it can be seen that captive operations mined approximately 32 million tons of coal in 1973, or equivalent to 9 percent of the total utility coal consumed during that year. Approximately 60 percent of this captive coal was low-sulfur (i.e., less than 1 percent sulfur).

Table 13 indicates the major coal reserves held by utilities. The 6.2 billion ton figure should be considered to be a minimum as complete data are not available at this time.

Oil Use By Utilities

With the increase in air pollution regulations and the decreased availability of natural gas, utilities have increased their use of oil in recent years. For the year 1971, oil use by the electric utilities amounted to 407.1 million barrels and accounted for 14.8 percent of the total Btu used. However, for the 12-month period ending June, 1974, use of oil by the utilities had increased by 24 percent to 505.1 million barrels and accounted for 20.6 percent of the total Btu consumed.

Trends in purchases of No. 6 fuel oil (residual) by utilities for the period April, 1973, through June, 1974, is given in Table 14. Residual fuel oil accounts for approximately 90 percent of total oil used by the utilities. Prior to the Arab Oil Embargo, spot purchases of such oil were not very significant as "contract" purchases accounted for 95 percent or more of total purchases. However, the bulk of these contracts were short-term as can be determined by analysis of the reports by individual utilities filed with the Federal Power Commission. Summarizing the sample data for June, 1974, in which 7,945,200 barrels of oil were purchased*; of that amount 16.7 percent were "spot" purchases, 48.1 percent were purchased on contracts which

*These sample data amount to 21 percent of total oil purchased in June 1974.

TABLE 12. CAPTIVE COAL PRODUCTION BY ELECTRIC UTILITIES, 1973

		1973 Tonnage	Low-sulfur Coal*
American Electric Power Company		6,924,621	1,653,747
Pacific Power and Light Company		6,124,176	6,124,176
Montana-Dakota Utilities Company		2,223,785	312,785
Duquesne Light Company		1,652,725	- -
Duke Power Company		1,150,000	1,150,000
Southern Company		1,118,272	1,118,272
Ohio Edison Company		246,928	- -
Black Hills Power and Light Company		750,000	750,000
Montana Power Company		4,253,681	4,253,681
Utah Power and Light Company		925,000	925,000
Alabama Electric Coop. Inc.		250,179	?
Pennsylvania Power & Light Company		3,486,639	- -
Texas Electric Service Co. Texas Power & Light Company Dallas Power and Light Co.	(1972 data)	1,790,000	1,790,000
Iowa Public Service Company		956,851	956,851
		31,852,857	19,034,512

* Less than 1.0 Percent

Sources: Compiled from 1974 Keystone Coal Industry Manual, 1973 Steam-Electric Plant Factors, Coal Age

TABLE 13. COAL RESERVES HELD BY UTILITIES

	Reserves (Million Tons)	Currently Producing
Pacific Power and Light Company	2500	yes
American Electric Power Corporation	1500	yes
Montana Power Company	1000	yes
Southern Electric Gen. Company	400	yes
Duke Power Company	250	yes
Public Service of NM	160	no
Pennsylvania Power & Light Company	95	yes
Allegheny Power Service Corporation	90	yes
Cedar Coal Company (a)	70	yes
Public Service Company of Indiana	50	no
Energy Development Company (b)	42	yes
Alabama Electric Coop., Inc.	1	yes
	6158	

(a) Owned by American Electric Power Service Corporation
(b) Subsidiary of Iowa Public Service Company

Source: 1974 Keystone Coal Industry Manual, p. 621-622

TABLE 14. TRENDS IN UTILITY PURCHASES OF NO. 6 (RESIDUAL) FUEL OIL BETWEEN APRIL 1973, AND JUNE, 1974 (a)

Month	Total No. 6 1000 Bbls	No.6 as Percent Total Oil	Contract Purchases		Spot Purchases		Percent of Total Purchases
			1000 Bbls	Average Price	1000 Bbls	Average Price	
April, 1973	33,372.2	93.0	32,174.6	68.5	1197.6	66.4	3.6
May	34,965.6	89.9	33,977.1	68.9	983.5	96.0	2.9
June	41,669.4	90.4	36,861.5	68.7	815.3	75.1	2.2
July	42,018.1	38.8	40,501.2	70.7	1516.9	76.8	3.7
Aug.	45,343.9	89.6	43,540.9	74.4	1802.9	68.3	4.1
Sept.	44,310.5	89.4	42,553.7	79.0	1756.8	72.6	4.1
Oct.	40,448.1	90.3	38,113.1	86.6	2334.7	75.8	6.1
Nov.	42,057.7	91.2	39,978.7	102.5	2079.1	94.6	5.2
Dec.	38,442.2	91.8	36,542.5	118.5	1399.7	127.1	5.2
Jan., 1974	38,690.5	90.4	35,496.3	154.4	3194.2	200.7	9.0
Feb.	34,342.7	92.1	31,573.6	182.8	2769.1	221.7	8.8
Mar.	34,471.7	92.3	32,922.0	188.1	1549.7	185.4	4.7
April	31,177.0	92.8	29,940.0	186.4	1236.9	189.2	4.1
May	31,947.1	90.0	29,150.2	188.7	2796.9	181.9	9.6
June, 1974	34,949.0	91.0	32,235.6	195.3	2713.3	190.2	7.8

(a) Source: Federal Power Commission, Monthly Reports of Cost and Quality of Fuels for Steam-Electric Plant, FPC Form No. 423.

(b) Cents per million Btu.

expire within 24 months; and only 34.7 percent were purchased under "long-term" contracts. Figure 4 indicates the importance of spot oil purchases on a state by state basis.

The term "long-term" is used in quotes because the bulk of these contracts are thought to be of 5 years duration or less. This assumption was confirmed by examination of the reports filed with the Securities and Exchange Commission by the 43 utilities sample. With only a few exceptions, the utilities indicated that they purchased most of their oil needs on short-term contracts or on a spot basis. Among the exceptions were Consolidated Edison Company of New York, Detroit Edison Company, and Public Service Electric and Gas Company which indicated that they purchased, at least, part of their residual oil requirements on long-term contracts. However, the length of the contracts was not specified.

It appears that the situation is changing and more utilities are moving in the direction of long-term contracts for oil as a means of assuring supplies. For example, Middle South Utilities, Inc., the large utility holding company, has arranged through its fuel purchasing subsidiary, System Fuels, Inc. (SFI), for a long-term contract to supply a part of its future oil requirements. SFI has contracted with ECOL, Ltd. to purchase 50,000 barrels per stream-day of low-sulfur No. 6 fuel oil (residual) from a new refinery to be constructed in Louisiana. The deliveries are to begin in 1977 and to continue for 20 years for a total commitment of 365 million barrels.

Houston Lighting and Power Co. which previously bought their oil on a spot purchase basis is now seeking to sign long-term contracts for its oil supplies. Public Service Company of Colorado signed a 5-1/4 year contract in October, 1973, with a Wyoming refinery to supply 207 million gallons of No. 2 fuel oil and 56 million gallons of No. 6 fuel oil over the period. Southern California Edison Co. has signed an agreement with an oil company to construct and operate a desulfurization facility near Los Agneles to produce 40 million barrels of low-sulfur fuel oil annually for at least the next 20 years.

In the past, direct involvement in the production of oil and gas by utilities was not widespread. For the most part utilities preferred to purchase fuels from other suppliers. However, a number of utilities have begun to make investment in exploration subsidiaries or to go into joint ventures with other companies which are involved in oil and gas exploration, development, and production. Examples of such companies are Montana Power Company, Florida Power and Light Company, Houston Lighting and Power Company,

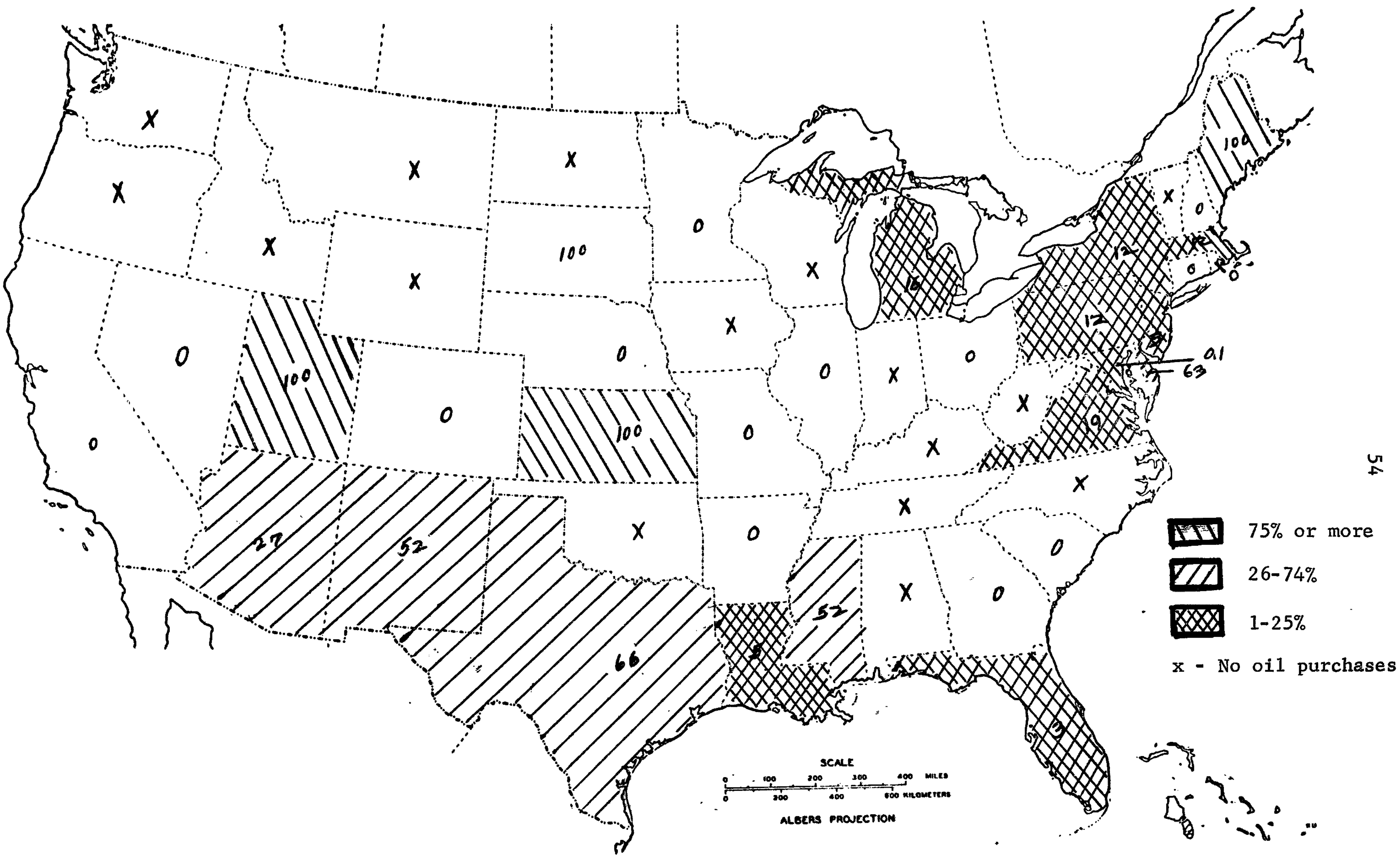

FIGURE 4. SPOT PURCHASES OF OIL AS PERCENT OF TOTAL PURCHASES BY UTILITIES, JUNE 1974

(Source: FPC)

Oklahoma Gas and Electric Company, Pacific Gas and Electric Company, Public Service Company of Colorado, Public Service Company of Oklahoma, Southern California Edison Company, and Texas Power and Light Company.

It appears that neither long-term contracts nor direct investment in oil reserves represents an important barrier to fuel switching at present. However, utilities appear to be moving into these two areas and such developments could become a significant barrier in the future.

Natural Gas

Traditionally, the great majority of natural gas sold to large utility consumers has been on long-term contracts, usually 20 years or more in length. The reason for such contracts was that the economics of pipelining is such that unit costs rise very sharply if a line is not used at near capacity. Therefore, it was in the best interest of the transmission company to guarantee that the line would be fully utilized. Long-term contracts with the big customers were a mechanism for assuring this situation.

Natural gas is sold in two main ways either on a "firm" basis or on an "interruptible" basis. In the latter case, it is understood that during periods of peak demand that customers with such contracts can be shut off. However, as the gas shortage has become more severe the length of curtailed service has increased and in some cases industrial and utility customers on firm contracts have been curtailed as well.

Table 15 indicates a recent estimate of the extent of natural gas curtailments in the utility sector between now and 1980. From this it can be seen that the total use of natural gas as boiler fuel will decline by 5.6 percent, with the only significant growth in such use to occur in the West South Central Region. Despite the sharp curtailment in gas use in most areas of the country, it can be seen that to replace the gas expected to be burned as utility boiler fuel in 1980 with coal would require the equivalent of 175 million tons, of which 140 million tons would be required in the West South Central Region alone.

TABLE 15. CHANGES IN NATURAL GAS USE BY THE ELECTRIC UTILITIES SECTOR 1972-1980 AND RELATIVE DEPENDENCE ON NATURAL GAS (1972)

Region	1972[(a)] Million Cubic Feet	1980[(b)] Million Cubic Feet	1972-1980 Change Quantity	1972-1980 Change Percent	Natural Gas As Percentage of Fossil Fuels[(c)]	Coal Equivalent (1980) Million tons[(d)]
New England	8,978	6,744	-2,234	-24.9	1	0.32
Middle Atlantic	106,020	127,200	+21,180	+19.9	4	5.96
East North Central	194,484	52,012	-142,472	-73.3	5	2.44
West North Central	404,763	258,513	-146,250	-36.1	36	12.10
South Atlantic	264,416	167,403	-97,013	-36.7	9	7.84
East South Central	129,331	10,272	-119,059	-92.1	9	0.48
West South Central	1,999,777	2,993,628	+993,851	+49.7	97	140.16
Mountain	251,621	49,119	-202,142	-80.3	38	2.30
Pacific	606,198	90,191	-516,007	-85.1	70	4.22
Total United States	3,978,673	3,754,070	-224,603	-5.6	27	175.77

(a) Fanelli, L. I., Natural Gas Production and Consumption: 1972, U.S. Bureau of Mines Mineral Industry Surveys, Natural Gas, Annual, 1973, 8.
(b) Future Requirements Committee, Future Gas Consumption of the United States, University of Denver Research Institute, Denver, Colorado, 1973, 44-51.
(c) National Coal Association, Steam-Electric Plant Factors, 1973 Edition, Washington, D. C., January, 1974, 53-54.
(d) Assuming 1030 Btu/ft^3 and 22 million Btu/ton for coal.

Based on the sample* fuel purchase data for June, 1974 referred to previously, it was found that only 2.2 percent of the gas purchased by utilities was under contracts which were due to expire within 24 months. Therefore, it is obvious that the great bulk of gas is sold under long-term contracts. However, the extent to which these contracts represent a barrier to fuel switching will depend upon whether such contracts can be honored by the pipeline companies and whether the Federal Power Commission and various state regulatory agencies will permit the contracted gas to be burned as boiler fuel. All evidence to date is that gas use by utilities will be phased out before all the contracts expire. Therefore, it is likely that the question of misplaced gas by the utilities probably will resolve itself within the decade.

Industrial Fuel Purchasing Practices

Coal

The use of coal for industrial purposes has been declining since the end of World War II under the impact of competition from oil, natural gas, and electricity. Preliminary data for 1973 indicate that industry used 24,028 trillion Btu's of energy, or 38.6 percent of the net energy used during that year. This energy was supplied by the following energy sources: coal--19 percent, natural gas--45 percent, oil products--25 percent, and electricity--11 percent. Industry used 156.0 million tons of coal of which 87.3 million tons were used for coke manufacture.

Industrial use of natural gas amounted to 10.5 trillion cubic feet of gas or 46 percent of the total gas used in 1973. The great bulk of this gas was used for fuel and power, with the remainder (6.6 percent) being used as raw material. Much of this gas use was "misplaced" in the sense that it was "clean" fuel being used where alternative fuels could be used. If only half of this gas was replaced by coal, it would increase the industrial use of coal by 230 million tons.

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*Sample represented 17 percent of total gas purchased by utilities in June, 1974.

Industrial use of oil products for fuel and power in 1973 amounted to 595.5 million barrels plus an additional 466.7 million barrels of products for use as raw material to industrial processes. Although precise data on the sulfur content of all oil products are not known, data from the USBM indicate that approximately half of the total residual oil is high in sulfur (1 percent sulfur or more). Industrial use of residual oil in 1973 amounted to 190.6 million barrels. If we assume that half of this oil was low-sulfur and therefore, misplaced, and should be replaced with coal, then it would increase the industrial demand for coal by an additional 27 million tons.

Although precise data on coal contracts in the industrial market could not be found, it was determined after discussion with a coal marketing man with one of the major coal companies that most industrial coal is sold on spot basis or short-term contracts. A 5-year contract is a long industrial contract. It was further learned that most coal companies are tailoring the output of their new mines to the utility markets. In light of this it is likely that if industrial consumers wish to increase their use of coal in the future to make up the deficits caused by declining availability of natural gas they will have to sign long-term contracts similar to those in use in the utility market.

Direct investment in the coal business by noncoal companies has increased sharply in recent years. However, with the exception of the steel companies, these operations are not strictly "captive" in the sense of the company owning the coal and producing it for their own internal use. The Keystone Coal Industry Manual indicated that captive coal operations by "other industries" (excluding steel and public utilities) in 1973 amounted to 7.3 million tons. However, much of this coal is not strictly "industrial" fuel, but instead is used for coke manufacture or chemical by-products. Alabama By-Products Corporation is a merchant coke producer; Semet-Solvay Division of Allied Chemical Company uses much of their output to produce coke rather than as steam coal; International Harvester Company's operation is in reality a captive coking coal operation for their Wisconsin Steel Division. Medusa Cement Company operates a small coal operation in Pennsylvania which appears to be "captive" to their Wampum Plant, but is not included in the above list.

However, it should be pointed out that there are a number of large industrial organizations which have investments in the coal business which could potentially become "captive" sources. Some of the larger of these firms include

Pullman, Inc.
Alco Standard Company
W. R. Grace and Company
Gulf Resources and Chemical Company
General Dynamics Corporation
Mead Corporation
American Smelting and Refining Company
Ideal Basic Industries.

If any or some of the firms find that gas or oil supplies for their industrial operations become tight, it would be possible for them to convert to coal and have an assured supply from their own subsidiaries. However, at present capitve coal use in the industrial sector is not significant.

Oil

No definite data on oil contracts used by industrial concerns could be secured, but it appears that they probably also use short-term contracts and spot purchases to meet their needs. Direct investment in captive oil and gas operations by industrial companies is not thought to be significant. Therefore, it does not appear that there are any significant business barriers to fuel switching in the case of oil. Environmental considerations and technical constraints affecting product control and plant operations are likely to be much more significant.

Natural Gas

Long-term contracts are the normal manner in which industrial consumers purchase natural gas. Most large industrial consumers have contracts for natural gas which extend well into the future. However, the mere existence of these contracts does not necessarily mean that they will be a significant barrier to fuel switching. In normal times, such contracts would be honored.

However, since natural gas is in short supply, end-use controls have been instituted by the Federal Power Commission and various state agencies. Under these schemes, customers are ranked according to the amount of gas they use, what they use gas for, and their ability to use alternative fuels. As a result, large industrial consumers who are equipped to use alternative fuels are likely to find themselves cut off from gas supplies despite having long-term contracts with the distribution companies.

According to the Federal Power Commission, industrial use of natural gas will grow at only 0.7 percent annually between 1971 and 1990 in contrast with the 4.9 percent annual rate between 1962 and 1971. As a result, natural gas's share of the total industrial market will decline from 47 percent in 1971 to only 35 percent in 1990. This would mean that 11.6 trillion cubic feet of gas would still be used by industry in 1990; this would be equivalent to 500-550 million tons of coal.

It is possible that various industrial consumers of gas will attempt to secure supplies by investing directly in gas producing companies so as to obtain a captive source of supply for their plants. However, there is a question whether they would be allowed to use such gas, if under end-use controls they do not quality as a priority user. Both Ford and General Motors have successfully drilled gas wells in Ohio, but General Motors is still waiting for permission from the State of Ohio to use this gas for their facilities. It is possible that they will be denied use of this gas in times of shortage and will be obliged to let residential consumers have it.

It appears that the feasibility of switching fuels in the case of natural gas will be more dependent on government policy than on the existence of long-term contracts or captive ownership of gas supplies.

FUEL TRANSPORTATION CONSTRAINTS TO FUEL SWITCHING

Consideration of possible fuel transport limitations to fuel switching must begin with the regional location of the misplaced fuels. The largest blocks, as summarized on Page 13, are found to be in the South Central, South Atlantic, Pacific, Mountain, and North Atlantic regions. Much of this misplaced fuel is natural gas being burned in utility or industrial boilers. Thus, the basic transportation requirement to accomodate fuel switching will be shipment of high-sulfur coal to replace natural gas. To identify the magnitude of the coal transportation problem, the amount of coal required to replace natural gas in large boilers may be compared with current coal shipments. The fuel use of the largest blocks of clean fuel in large sources, which are summarized on Page 13, were combined by region and tabulated in Table 16. The quantity of high-sulfur coal equivalent to the clean fuel was calculated for each region. The actual coal shipments received in each region during 1972 are given in Table 16 for comparison. If all of the clean fuel in these sources were to be replaced by high-sulfur coal, substantial increases in coal transport would be required in the South Central, Pacific, and Mountain regions. Much more modest increases would be required in the other regions.

The Federal Energy Administration projects substantial increases in coal flows by 1985[6]. Rail transport of coal was projected to increase by more than 200 percent, while water movements were projected to increase about 60 percent. FEA concludes that the rail and water transport systems would face problems but that they would be able to accomodate such increases. The ability of the coal transport systems to expand to meet increased requirements depends primarily on the existence of a continuing demand for the service. Where an established need exists, the transport systems have expanded to provide the service. In view of the fact that equipment constraints will prevent switching of a portion of the natural gas, the transportation network should be able to accomodate the altered fuel distribution called for by the fuel switching which is achievable.

TABLE 16. COAL EQUIVALENT OF MISPLACED CLEAN FUELS IN LARGE SOURCES

Region	Fuel	Misplaced Clean Fuel, 10^{12} Btu/Year	Coal Equivalent 10^{6} Ton/Year	Actual 1972 Shipments Received
South Central	N. Gas	2508	103	85
Pacific	N. Gas/Resid	749	31	4.6
Mountain	N. Gas/L S Coal	744	31	26
N. Atlantic	L S Coal/Resid	750	31	79
S. Atlantic	N. Gas/L S Coal	973	40	97
W. N. Central	N. Gas	286	12	40
E. N. Central	N. Gas	318	13	206

IDENTIFICATION OF BLOCKS OF FUELS SUITABLE FOR SWITCHING

A summary of the data from Table 7 shows the following quantities of misplaced fuels, in 10^{12} Btu/year:

Fuel	Large Sources	Small Sources
Misplaced Coal	1,804	2323
Misplaced Oil	2,978	3479
Misplaced Natural Gas	10,457	--
Totals	15,239	5802

The constraints which limit exchange of these fuels, as discussed in the preceding sections would have to be evaluated on a source-by-source basis in order to arrive at a completely valid conclusion regarding the quantities of fuel which are, in fact, free to be switched. However, useful conclusions may be drawn based on the generalized limitations which may be summarized as follows:

- Gas- or oil-fired boilers cannot be switched to coal unless they were originally designed for dual fuel or designed for coal and subsequently converted.
- Coal-fired boilers which were converted to oil may not be reconvertible.
- One coal can be exchanged for another coal if proper care is taken to ensure that the properties of the new coal are compatible with the furnace and boiler design. Derating of the boiler is often required.
- Approximately 75 percent of utility purchases of coal are on a long-term contract basis.
- Industrial coal is purchased mainly on a spot basis.
- Captive production of coal is less than 10 percent of the total coal production.
- Long-term contracts for oil and gas do not appear to be a barrier to switching.
- Transportation constraints appear to be less restrictive than equipment and business factors.

Coal in Large Sources

Low-sulfur coal in large sources can be replaced by high-sulfur coal or high-sulfur residual oil. Equipment limitations can be overcome in this case. Business constraints in the form of long term contracts will be more limiting. Assuming that such contracts are about uniformly distributed with respect to low- and high-sulfur coal, 25 percent of this block, or 450×10^{12} Btu/year, would be expected to be purchased on a spot basis and, therefore, free for switching.

Coal in Small Sources

High-sulfur coal in small sources can be replaced by low-sulfur coal, by low-sulfur residual oil, by distillate oil, or by natural gas. Again, equipment constraints can be overcome and the primary limitation is that of long-term contracts. Assuming the 25 percent of the utility coal, and all of the industrial and commercial coal is free from this restraint, about 2000×10^{12} Btu/year would be available for switching.

Oil in Large Sources

Low-sulfur oil can be replaced with high-sulfur oil, or by high-sulfur coal, if the boiler were originally designed for coal. Boilers which can be converted to coal represent about 1200×10^{12} Btu/year. The remainder could be switched to high-sulfur residual oil, thus the entire block, about 3000×10^{12} Btu/year, is essentially available for switching. The limitation would be the availability of the replacement fuel.

Oil in Small Sources

High-sulfur oil in small sources can be replaced by low-sulfur residual oil, by distillate oil, or by natural gas. Equipment constraints can be overcome. Little of the high-sulfur oil is expected to be under long-term contract, thus essentially all of this block, or about 3500×10^{12} Btu/year, is available for switching.

Natural Gas in Large Sources

Natural gas cannot be replaced by coal unless the boiler were originally designed for coal. Only about 600×10^{12} Btu/year of the natural gas-fired boiler capacity could be fired with high-sulfur coal. The only other replacement fuel for this large block is high-sulfur residual oil. This change can be accomodated with respect to equipment factors. The primary limitation would be the availability of the replacement fuel.

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APPENDIX A

LIST OF ELECTRIC UTILITIES WHOSE PROSPECTUSES AND REGISTRATION STATEMENTS WERE EXAMINED TO OBTAIN INFORMATION ON FUEL CONTRACTS AND PURCHASING PROCEDURES

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LIST OF ELECTRIC UTILITIES WHOSE PROSPECTUSES AND REGISTRATION STATEMENTS* WERE EXAMINED TO OBTAIN INFORMATION ON FUEL CONTRACTS AND PURCHASING PROCEDURES

American Electric Power Company, Inc.
Arizona Public Service Company
Arkansas Power and Light Company
Baltimore Gas and Electric Company
The Cleveland Electric Illuminating Company
Commonwealth Edison Company
The Connecticut Light and Power Company
Consolidated Edison Company of New York, Inc.
Consumers Power Company
The Detroit Edison Company
Duquesne Light Company
Duke Power Company
Florida Power Corporation
Florida Power and Light Company
Houston Lighting and Power Company
Iowa Electric Light and Power Company
Iowa Power and Light Company
Louisiana Power and Light Company
The Montana Power Company
Nevada Power Company
New England Power Company
New Orleans Public Service, Inc.
Northern States Power Company
Oklahoma Gas and Electric Company
Pacific Gas and Electric Company
Pacific Power and Light Company
Pennsylvania Electric Company
Philadelphia Electric Company
Portland General Electric Company
Potomac Electric Power Company
Public Service Company of Colorado
Public Service Company of Indiana, Inc.
Public Service Company of New Mexico
Public Service Company of Oklahoma
Public Service Electric and Gas Company (New Jersey)
Puget Sound Power and Light Company
Southern California Edison Company
The Southern Company
Texas Power and Light Company
Union Electric Company
Utah Power and Light Company
Virginia Electric and Power Company
Wisconsin Power and Light Company

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*As filed with Securities and Exchange Commission

APPENDIX B

LIST OF FIRMS AND AGENCIES CONTACTED DURING COURSE OF RESEARCH

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National Coal Association

Federal Energy Administration

Federal Power Commission

Securities and Exchange Commission

New York State Public Utilities Commission

Amax Coal Company

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16. ABSTRACT The report gives results of a study to evaluate the potential of fuel switching as an element of an overall strategy for the control of sulfur oxide emissions from stationary sources. Blocks of misplaced fuels (i.e., clean fuels now burned in large sources and dirty fuels now burned in small sources) were identified. Various potential constraints to switching the misplaced fuels were evaluated. These included: equipment constraints, business constraints, and fuel transportation constraints. From these evaluations, the quantities of misplaced fuels were identified which are not limited by any of the constraints, and therefore which can be considered suitable for switching.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Air Pollution Control	13B
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Distribution	Fuel Switching	14A
Fuel Consumption	Distribution Flexibility	
Sulfur Oxides		07B
Substitutes		
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