129
5-9-78

BNL 50771

Lh. 44

MASTER

A STUDY OF POTENTIAL COAL UTILIZATION 1985-2000

DOUGLAS GUNWALDSEN, NARESH BHAGAT, AND MORRIS BELLER

December 1977

Prepared by the
TECHNOLOGY ASSESSMENT GROUP
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS

BROOKHAVEN NATIONAL LABORATORY
ASSOCIATED UNIVERSITIES, INC.

UNDER CONTRACT NO. EY-76-C-02-0016 WITH THE
UNITED STATES DEPARTMENT OF ENERGY

DISCLAIMER

BNL 50771
UC-95c
(Energy Conservation—Systems Modeling and
Performance - TID-4500)

A STUDY OF POTENTIAL COAL UTILIZATION 1985-2000

DOUGLAS GUNWALDSEN, NARESH BHAGAT, AND MORRIS BELLER

December 1977

Prepared by the
TECHNOLOGY ASSESSMENT GROUP
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS

BROOKHAVEN NATIONAL LABORATORY
UPTON, NEW YORK 11973

Printed in the United States of America
Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
Price: Printed Copy $9.00; Microfiche $3.00

January 1978 700 copies

We shall not cease from exploration
and the end of all our exploring
Will be to arrive where we started
and know the place for the first time.

- T. S. Eliot

ACKNOWLEDGEMENTS

The authors wish to express their appreciation to the many individuals at the National Center whose suggestions have improved the quality of this report. Special thanks are owed Dr. Kenneth Hoffman, Head of the National Center for Analysis of Energy Systems, and Mr. Charles Mandelbaum of DOE for reviewing and extensively commenting on drafts of this document.

Mr. Charles Feibel collected much of the background information, and Mr. Stanley Majeski ably oversaw the preparation of the many figures required for our presentation.

We owe special thanks to Ms. Mary Lou Weis for coordinating the preparation of this document, and to Ms. Onre Corace and Ms. Marge Gallitelli for their patience in typing the drafts. Special thanks are also due to Ms. Francine Donnelly, who volunteered to type the final version.

ABSTRACT

The 1973 oil embargo has heightened our nation's need to place greater reliance on our indigenous coal resources. At the same time, changing environmental standards and rapidly increasing mining costs have heightened interest in our vast, low sulfur western coal reserves. The President's National Energy Plan calls for an increase in coal use from 681 million tons in 1976 to 1,066 million tons in 1985. These factors are expected to result in regional coal production, transportation and demand patterns radically different from historical trends.

Growing energy requirements beyond 1985 will require continued expansion of coal use and will impose a considerable strain on the mining and transportation industries. National projections tend to obscure the reality that the impacts of this expansion will not be borne equally throughout the nation, but will fall heavily on the coal producing regions, particularly on those in the west. The Federal government's policy to develop a commercial synthetic fuels industry may result in a new and growing coal market during this period, as well.

To examine these factors, regional supplies and demands for coal, oil, and natural gas were estimated for 1985 and 2000. National coal supplies of 1018 million tons in 1985 (consistent with FEA's 1976 National Energy Outlook) and 1836 million tons in 2000 were employed in our analysis.

In order to estimate transportation and consumption patterns for these supplies a substantial data base was assembled estimating interregional energy transportation costs. Delivered energy costs were then estimated regionally by combining the wellhead or mine-mouth costs of the fuel resource with these transportation charges. Coal transportation and use patterns for electric utilities, industrial steam, and synthetic fuel producers were determined by linking the supply, demand, and cost estimates and solving the resulting network through a cost-minimizing linear program formulation. By maintaining consistency at the regional level, this formulation allowed the determination of the most likely markets for western coal and an investigation of the regional development of synthetic gas and liquids production.

The coal use patterns generated through this formulation constituted the basis of an investigation of constraints which might preclude this development. Major findings of this study include:

1. Under existing environmental regulations, western coal will be competitive in utility markets well east of Chicago. With the passage of the Best Available Control Technology (BACT) proposal in the amendments to the Clean Air Act, requiring flue gas desulfurization for all new coal-burning power plants, this eastward penetration will be substantially reduced; the prospects for nuclear power are improved by passage of BACT.

2. Roughly 215 million tons of subbituminous coal were allocated to regions east of the Rocky Mountains in 1985; in 2000 this flow increased to 415 million tons. While, with track upgrading and localized expansion, it appears that the railroads can physically accommodate this increased traffic, serious doubts exist as to whether the impacts of this intensive traffic would be acceptable to communities located along western rail corridors. Granting eminent domain privileges for slurry pipelines is a viable option for relieving some of this strain and a means of introducing a degree of competition to western coal transport. These estimates of western coal flow may be reduced because of the passage of BACT legislation, but there is still much uncertainty regarding technological control costs and possible emission standards to be imposed by EPA.

3. Cost considerations imply that synthetic crude producers would locate near low-cost western coal fields and pipe their product to midwestern markets. Higher gas transport costs coupled with utility competition for low-sulfur western coal indicate that SNG producers would be more likely to tap high sulfur Appalachian and midwestern coal fields. The high transport costs for low-Btu gas restricts the use of this coal derivative to areas such as the Ohio River, which are close to coal fields and to heavy industrial consumers.

EXECUTIVE SUMMARY

Background

The 1973 oil embargo served notice to the United States that we could no longer depend on reliable, inexpensive imported energy as a cornerstone of our industrialized society. The embargo brought into focus the realization that our energy resources, while vast, are nevertheless finite. It also demonstrated that the preservation of our standard of living in the future would require a concerted effort to minimize our waste of energy and aggressive development of our untapped energy resources. At the same time, a growing recognition of the damage to our health and environment resulting from environmental pollution has led to the conviction that such degradation can no longer be permitted. Caught between these apparently conflicting social goals is coal, our most plentiful but potentially most polluting fossil energy resource. Resource and supply considerations dictate that our coal fields be developed and substituted as rapidly as possible for our dwindling reserves of oil and natural gas.*

At the turn of this century, coal supplied 90% of our nation's energy consumption; by 1972, coal supplied only 18%, while oil and gas supplied 77%. Conversely, our coal resource base is estimated to be 15 times as great as our combined oil and gas resources.

Even if it were possible to return to our turn-of-the century consumption patterns, few would advocate such draconian measures. Nevertheless, it is apparent that coal's share of our national energy consumption will increase dramatically during the next 25

---

* A key strategy of the President's National Energy Policy (NEP) is to force utilities and large industries to convert to coal by taxing their use of oil and natural gas.

years, and continue into the twenty-first century. Environmental considerations will demand that the impacts of increasing coal use be minimized; the most likely routes for achieving these twin goals will be through increasing coal-steam electric generation and through the increased use of synthetic fuels derived from coal.

Following the second world war, increasing availabilities of inexpensive oil and natural gas, and more recently, the growth of the nuclear power industry have eroded coal's market shares of industrial and electric utility energy consumption. This trend accelerated in the 1960's through increasing environmental concerns, most notably by the passage of the Clean Air Act in 1963.

While this period was one of unprecedented growth and prosperity for the nation as a whole, the coal industry experienced a period of protracted stagnation. Coal prices hovered between $4.50-5.00/ton in current dollars between 1950 and 1968, in spite of increasing labor and equipment costs. The depressed state of the coal industry carried over to the railroad industry, where the decline in coal shipments undoubtedly played a part in the financial problems of many Northeastern railroads.

Events since the 1973 embargo have profoundly altered this situation. By 1975, the average mined price of coal had risen to $18.75 per ton. Increasing uncertainty over the future of nuclear power, both through citizen intervention and through increasing regulatory delay and roadblocks, has soured many utilities on this alternative. Curtailments of natural gas supplies to "interruptible" customers and the uncertainty of imported oil sources are making many industrial users take a fresh look at coal. As a result of these and other favorable indications, the coal and rail industries have begun massive capital expansion and renovation programs in anticipation of a rapid growth in coal demand.

Analytical Methodology

The environment in which the coal industry will grow and develop during the coming decades will be radically different from the industry's historical experience. Three factors are largely responsible for this. First, the economic impact of environmental regulations is expected to lead to a willingness among coal consumers in the electric utility and industrial sectors to pay substantial premiums for low sulfur coal. Secondly, coal users have recently begun looking to more distant coal supply regions to avoid some of the dramatic increase in coal mining costs. Finally, if expectations of an expanding synthetic fuels industry in the 1980's and 1990's are borne out, a new and aggressive competitor will enter the coal market.

All the primary actors in this "new environment" will be financially sophisticated, and the capital intensive coal-using facilities will force market participants to aggressively seek out their least costly alternatives. As a result, a growing competition may be expected to develop for the most desirable coal supplies. The basis of this competition will be the delivered cost of coal energy, constrained by coal availability, environmental regulations, and the particular characteristics and requirements of each coal user.

Perhaps the most visible example of these changes is the tremendous interest displayed by eastern and midwestern utilities in low sulfur western coal, particularly in the vast Powder River Basin coal field. Coal production in Montana and Wyoming jumped from roughly 20 million tons in 1970 to 80 million in 1975 and, if FEA projections are borne out, will be roughly 250 million tons by 1985. More generally, FEA projects that western coal, which accounted for 15% of 1974 production, will account for 38% by 1985.

In order to examine the impacts of this acceleration in coal use, regional supplies and demands for fossil fuels were estimated for 1985 and 2000. These estimates were made on the basis of the nine census regions for fossil fuel demands, including separate estimates for electric power generation and industrial steam coal demands. Coal supply estimates for 1985 were adopted from FEA's 1976 National Energy Outlook for eight Supply Regions, and were extrapolated to the year 2000 using the regional growth rates estimated in the Project Independence Report (see Figure S-1 for supply and demand regions).

The bulk of the analytical effort was directed at examining the options available to utility, industrial, and synthetic fuel coal users in each region for satisfying their requirements. The "value" of each option was measured by its delivered cost to each user type in each of the nine demand regions. The delivered cost was determined by summing the sale price of coal at the mine, the estimated transportation cost, and the cost of any ancillary environmental control required (SO_2 removal for high sulfur coal). Similarly, oil and gas supplies from the Gulf Coast, Alaska, regional producing districts, the outer continental shelves (OCS), and from import sources of oil and liquefied natural gas were estimated and included in the analysis. The quantities and minemouth or wellhead prices used in this study are displayed in Table S-1.

An effort was made to develop consistent and realistic estimates. The basis of the transportation charges were the estimates developed by Bechtel for their RESPONS model, modified where necessary for the specific requirements of this study. For example, while electric utility rail shipments were assessed at unit train rates, industrial shipments were charged at higher spot rail rates, reflecting the belief that individual industrial steam coal users

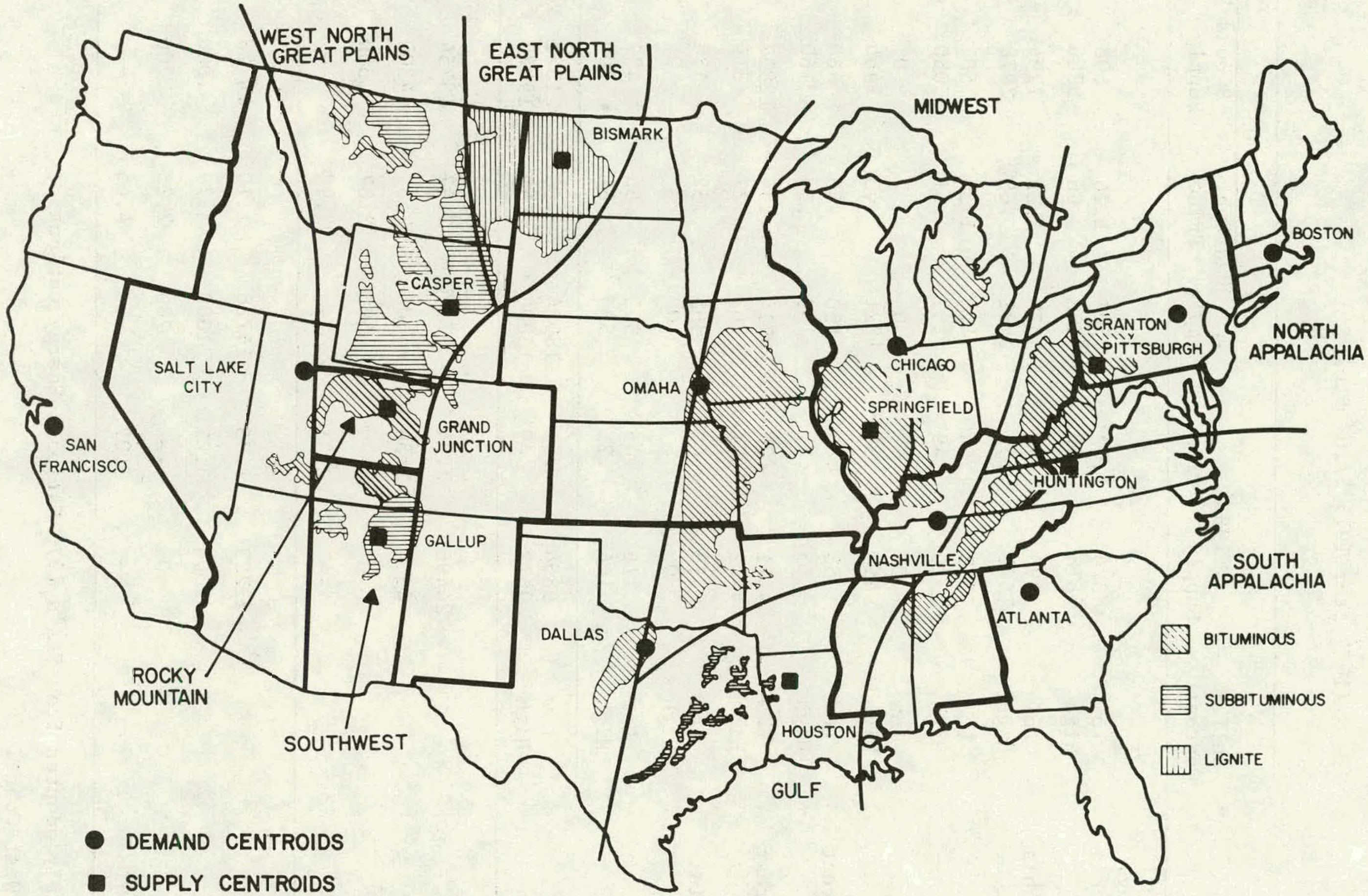

Figure S-1. Coal supply and demand regions and centroids.

Table S-1

Quantities and Raw Fuel Costs
of Fossil Fuels
(10^{12} Btu; 1975 \$/10^6 Btu)

	Sulfur Content	1985[1] Supply	1985[1] Price	2000 4.5 Quad Syn. Supply	2000 4.5 Quad Syn. Price	2000 9 Quad Syn. Supply	2000 9 Quad Syn. Price
Coal (Non-Coking)							
North Appalachia	Low	374	1.02	507	1.26	608	1.26
	High	3618	.53	4888	.66	5866	.66
South Appalachia	Low	3890	.98	6078	1.22	7294	1.22
	High	1589	.52	2482	.65	2978	.65
Midwest	Low	312	1.04	418	1.30	502	1.30
	High	3320	.49	4233	.61	5080	.61
Gulf	Low	0		0		0	
	High	453	.34	1221	.43	1465	.43
East North Great Plains	Low	353	.45	550	.56	660	.56
	High	85	.31	133	.39	160	.39
West North Great Plains	Low	4471	.28	10714	.34	12857	.34
	High	402	.21	262	.27	314	.27
Rocky Mountain	Low	338	.42	365	.52	438	.52
	High	0		0		0	
Southwest	Low	116	.45	353	.56	422	.56
	High	146	.25	589	.31	700	.31
Total U.S.	Low	9854	.61	18984	.68	21831	.68
	High	9613	.49	13808	.60	15879	.60
Oil							
Lower 48		24496	2.24	18754	2.87	18754	2.87
North Slope[2]		4300	2.54	4300	2.87	4300	2.87
Atlantic OCS[3]		0	--	590	2.87	590	2.87
Imports[4]		--	2.31	--	2.97	--	2.97
Natural Gas							
Lower 48		21223	1.93	14728	2.19	14728	2.19
North Slope[5]		1000	3.22	1000	3.79	1000	3.79
Atlantic OCS[3]		0	--	700	2.25	700	2.25
Imports (LNG)[4]		--	3.07	--	4.45	--	4.45

[1] 1985 coal supply adopted from FEA's 1976 National Energy Outlook.

[2] Delivered to West Coast.

[3] Delivered to East Coast.

[4] Delivered to East Coast. Supplies were unbounded, but only permitted to enter after all other sources (including synthetics) had been exhausted.

[5] Delivered to Chicago.

would seldom require the volumes of coal that would justify unit train operations (generally one million tons per year). Similarly, where a synthetic oil or high Btu gasification plant was located adjacent to the existing pipeline network, the transportation charges to deliver its product to the regional markets were assumed somewhat lower than if new pipeline was required, reflecting a higher capital charge assigned to new line construction.

Once these costs had been estimated, interregional fossil fuel distribution patterns were generated via a linear programming formulation. The objective function selected was that of minimizing the cost of all fossil fuels to all users. This was felt to provide a reasonable first-order estimate of the pattern that a perfectly functioning market might select.

The patterns generated were not intended to be predictive; they ignore the dynamic nature of energy investments, and, of course, the reality that much of the energy industry is regulated in ways that might substantially bias a free market solution. However, the patterns provide a reasonable basis for examining the regional impacts of accelerating coal consumption. They also expose some of the major cost elements underlying the competition for different coal sources and between regions and markets. These patterns are displayed in Tables S-2, S-3, and S-4.

Conclusions

Under existing SO_2 regulations for the electric utility industry, the cost estimates generated in this study show that low sulfur western subbituminous coal is competitive with eastern coal (except at the minemouth) as far east as Indiana. The current EPA initiative (Best Available Control Technology (BACT)) of installing flue gas desulfurization at all new coal-fired plants

Table S-2

1985 Regional Allocation of Coal
to Various End Uses
(1.1 Quad Synthetics; Entries are 10^6 Tons)

Supply Region	Sulfur Content	Supply (10^6 Tons)	End Use	Fraction to End Use (%)	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	Low	15.2	Utility	100	3.6	11.6							
			Industrial										
	High	147.1	Utility	57		83.3							
			Industrial	18	1.4	24.4							
			Low Btu	18		27.0							
			High Btu	7	11.0								
			Liquids										
South Appalachia	Low	149.6	Utility	100			96.7	7.3	45.6				
			Industrial										
	High	61.1	Utility	7				4.2					
			Industrial	45			20.6		13.8				
			Low Btu										
			High Btu										
			Liquids	5									
Midwest	Low	14.2	Utility	100				14.2					
			Industrial										
	High	150.9	Utility	50				76.2					
			Industrial	50				55.4		12.5			
			Low Btu										
			High Btu										
			Liquids					6.8					
Gulf	High	20.6	Utility	37			7.7						
			Industrial	63						12.9			
			High Btu										
			Liquids										
East North Great Plains	Low	25.2	Utility	100					25.2				
			Industrial										
			High Btu										
			Liquids										
	High	6.1	Utility										
			Industrial										
			High Btu	100						6.1			
			Liquids										
West North Great Plains	Low	251.2	Utility	100				88.5		91.6	35.7	35.3	
			Industrial										
			High Btu										
			Liquids										
	High	6.1	Utility										
			Industrial	100								3.2	2.9
			High Btu										
			Liquids										
Rocky Mountain	Low	12.7	Utility	100								4.5	8.2
			Industrial										
			High Btu										
			Liquids										
Southwest	Low	7.7	Utility	100							7.7		
			Industrial										
			High Btu										
			Liquids										
	High	12.9	Utility										
			Industrial	39									5.0
			High Btu	61									7.9
			Liquids										

Table S-3

2000 Regional Coal Allocation

(4.5 Quad Synthetics; Entries are 10^6 Tons)

Region	Sulfur Content	Supply (10^6 Tons)	End Use	Fraction to End Use (%)	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia		20.6	Utility	100		20.6							
			Industrial										
	High	198.7	Uitlity	43		85.5							
			Industrial	19	2.1	35.6							
			Low Btu	32		27.0		37.5					
			High Btu	6		11.0							
			Liquids										
South Appalachia	Low	245.1	Utility	100	5.2	40.0	129.3		70.6				
			Industrial										
	High	100.1	Utility										
			Industrial	83			36.1		23.7	19.2	3.9		
			Low Btu										
			High Btu										
			Liquids										
Midwest	Low	19.0	Utility										
			Industrial										
	High	192.4	Utility										
			Industrial	43				83.6					
			Low Btu	10				18.6					
			High Btu	43				83.4					
			Liquids	4				6.8					
Gulf	High	87.2	Utility										
			Industrial	62							54.1		
			High Btu										
			Liquids										
East North Great Plains		39.3	Utility										
			Industrial										
			High Btu	45						17.6			
			Liquids										
	High	9.5	Utility										
			Industrial										
			High Btu	100						9.5			
			Liquids										
West North Great Plains	Low	601.9	Utility	87				236.0		136.6	67.2	54.2	26.7
			Industrial										
			High Btu	5								30.6	
			Liquids	8								50.6	
	High	14.7	Utility										
			Industrial	80								11.8	
			High Btu	20						2.9			
			Liquids										
Rocky Mountain	Low	15.2	Utility	34									5.2
			Industrial	66									10.0
			High Btu										
			Liquids										
Southwest	Low	19.8	Utility										
			Industrial										
			High Btu										
			Liquids										
	High	33.1	Utility										
			Industrial										
			High Btu	24									7.9
			Liquids	76								25.2	

Table S-4

2000 Regional Coal Distribution

(9 Quad Synfuel Production; Entries are 10^6 Tons)

Supply Region	Sulfur Content	Supply (10^6 Tons)	End Use	Fraction to End Use (%)	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	Low	24.7	Utility	100		24.7							
			Industrial										
	High	238.5	Utility	36		84.7							
			Industrial	16	2.1	35.6							
			Low Btu	43		47.6		57.4					
			High Btu	5		11.1							
			Liquids										
South Appalachia	Low	294.1	Utility	90	5.2	36.8	125.8	25.7	70.6				
			Industrial										
	High	120.1	Utility										
			Industrial	65			36.1		23.7	19.2			
			Low Btu	15			17.5						
			High Btu	20				23.6					
			Liquids										
Midwest	Low	22.0	Utility										
			Industrial										
	High	230.9	Utility										
			Industrial	36				83.2					
			Low Btu	14				31.5					
			High Btu	50				116.2					
			Liquids										
Gulf	High	104.6	Utility	6			6.3						
			Industrial	58							61.0		
			High Btu										
			Liquids										
East North Great Plains	Low	47.1	Utility										
			Industrial										
			High Btu	83						39.3			
			Liquids	17				7.8					
	High	11.4	Utility										
			Industrial										
			High Btu	83						9.5			
			Liquids	17				1.9					
West North Great Plains	Low	722.3	Utility	65				200.4		136.7	49.4	54.2	22.6
			Industrial										
			High Btu	16								119.1	
			Liquids	19				69.6				70.4	
	High	17.6	Utility										
			Industrial	67								11.8	
			High Btu										
			Liquids	33				5.8					
Rocky Mountain	Low	18.3	Utility	45									8.3
			Industrial	55									10.0
			High Btu										
			Liquids										
Southwest	Low	23.7	Utility	75							17.7		
			Industrial										
			High Btu	25									6.0
			Liquids										
	High	39.3	Utility										
			Industrial										
			High Btu	84									33.0
			Liquids	16								6.3	

may invalidate this conclusion to some extent; uncertainties concerning the relative costs of scrubbing high and low sulfur coals make the impact of such a policy difficult to gauge at this time.

The cost-minimizing distribution patterns obtained indicate that western coal may generate as much as 29% of East Central coal-derived electricity by 1985 and 65% by 2000. This will result in very substantial impacts to the relatively undeveloped western coal regions, and it seems likely that the states of Montana and Wyoming will seek to protect these areas. Uncertainty concerning federal and state initiatives, then, will both tend to retard western coal development, so these results should properly be thought of as unconstrained development cases.

Increasing coal production will represent a stimulus to the transportation industry and for the beleaguered railroad industry in particular. Average distances for utility coal shipments are estimated to increase from 325 miles at present to as much as 250 miles by the year 2000. Coupled with the increase in utility coal use, this represents a fourfold increase in ton-miles shipped. Coal currently accounts for roughly 15% of total rail ton-mileage. These shipments indicate that coal might account for almost 30% of freight ton-miles by 1985 and 37% by 2000.

No group stands to gain more from this boom than the western railraods. Rail revenues resulting from western coal shipments in 1975 amounted to roughly half a billion dollars. The 1985 distribution increases this figure to $3 billion, and by 2000 to $7.5 billion, all expressed in 1975 dollars. It was estimated that utility coal shipments originating west of the Mississippi River would increase tenfold by the year 2000. Although it appears that the western railraods could accommodate this traffic through track upgrading, adding bypass sidings and building additional track near the coal fields, an increase of this magnitude will result in substantial impacts to the communities along the major east-west rail corridors. The postulated 1985 shipments, for example, would require that an east-bound, 110-car unit train leave the Powder River Basin every 24 minutes. By 2000, this frequency would be increased to one train every 12 minutes. In light of these anticipated volumes and the lack of competition for shipping western coal, the continuing denial of eminent domain privileges to the slurry pipeline industry seems a counter-productive policy.

The emergence of a commercial synthetic fuels industry was found to depend on extremely high prices of naturally occurring oil and gas (well in excess of $3.00 per million Btu), on governmental guarantees or on some combination of the two. The low conversion efficiency of these processes (60-70%) should cause the synthetic fuel industry to seek the least costly sources of coal, since they will be forced to buy three Btu's of coal for every two Btu's they produce. Most of these sources are located in the West, where limited water availability coupled with substantial transportation costs to pipe the products to eastern markets will tend to restrict their development. A preliminary examination of water resources indicates that water availability will not be a constraint up to 2000; however, political intervention may pose a constraint. The high transportation costs of building pipelines to ship synthetic high-Btu gas eastward, coupled with utility competition for the generally low sulfur coal, were found to roughly nullify the cost advantage of using western coal. In all three scenarios, roughly equal synthetic high-Btu gas capacity was sited east and west of the Mississippi River.

This was not true, however, of syncrude production, where the very low cost of shipping crude oil and petroleum products was found to result in a strong cost preference for western production.

It seems likely that a synthetic gas industry would favor high-sulfur eastern fields, while syncrude developers would prefer western locations. Without a clearly articulated federal policy on synfuels development it is impossible to extend these findings. However, should the Presidential National Energy Plan be implemented as proposed, with tax incentives for coal conversion and penalties on natural gas use by industry, a powerful spur is provided for use of low Btu gas by industry. This is shown in Table S-5, where small decentralized low Btu gas plants can produce gas (150 Btu/cu-ft) in various demand regions in the range of $2.02 to $2.71/$10^6$ Btu in 1985, and $2.44 to $3.03/$10^6$ Btu in 2000. These would be competitive with gas to industry priced at about $3.65 and $4.25/$10^6$ Btu in 1985 and 2000, respectively, under the National Energy Plan.

Figure S-2 presents a regional cost comparison of coal- and nuclear-generated electricity, under New Source Performance Standards (NSPS) and probable Best Available Control Strategy (BACT) standards.

Under NSPS standards, coal was found to be the least cost technology through the West, approximately the same cost as nuclear generation in the East Central regions and generally more expensive than nuclear power along the Atlantic coast.

With the adoption of BACT standards, coal-fired electricity will become more expensive than nuclear throughout the country, except at the minemouth.

TABLE S-5

LOW BTU GAS PRODUCTION COSTS*

Demand Region	Average Delivered Coal Price		Total Low Btu Gas Cost (Coal Price and Conversion Cost)	
	1985 ($/$10^6$ Btu Coal)	2000 ($/$10^6$ Btu Coal)	1985 ($/$10^6$ Btu Gas)	2000 ($/$10^6$ Btu Gas)
New England	.92	1.20	2.53	2.90
Middle Atlantic	.83	1.08	2.41	2.74
South Atlantic	.86	1.11	2.45	2.78
East North Central	.75	.96	2.31	2.58
East South Central	.83	1.07	2.41	2.73
West North Central	.87	1.16	2.46	2.85
West South Central	.53	.91	2.02	2.52
Rocky Mountain	.64	.85	2.16	2.44
Pacific	1.06	1.30	2.71	3.03

*For small capacity plants, 150 Btu/cu-ft, $6x10^9$ Btu/day, based on MOPPS study preliminary data:

Total capital cost: $\$12.7x10^6$
Plant life: 20 yr
O & M cost: $\$0.29/10^6$ Btu output
Plant factor: 0.9
Conversion efficiency: 0.76

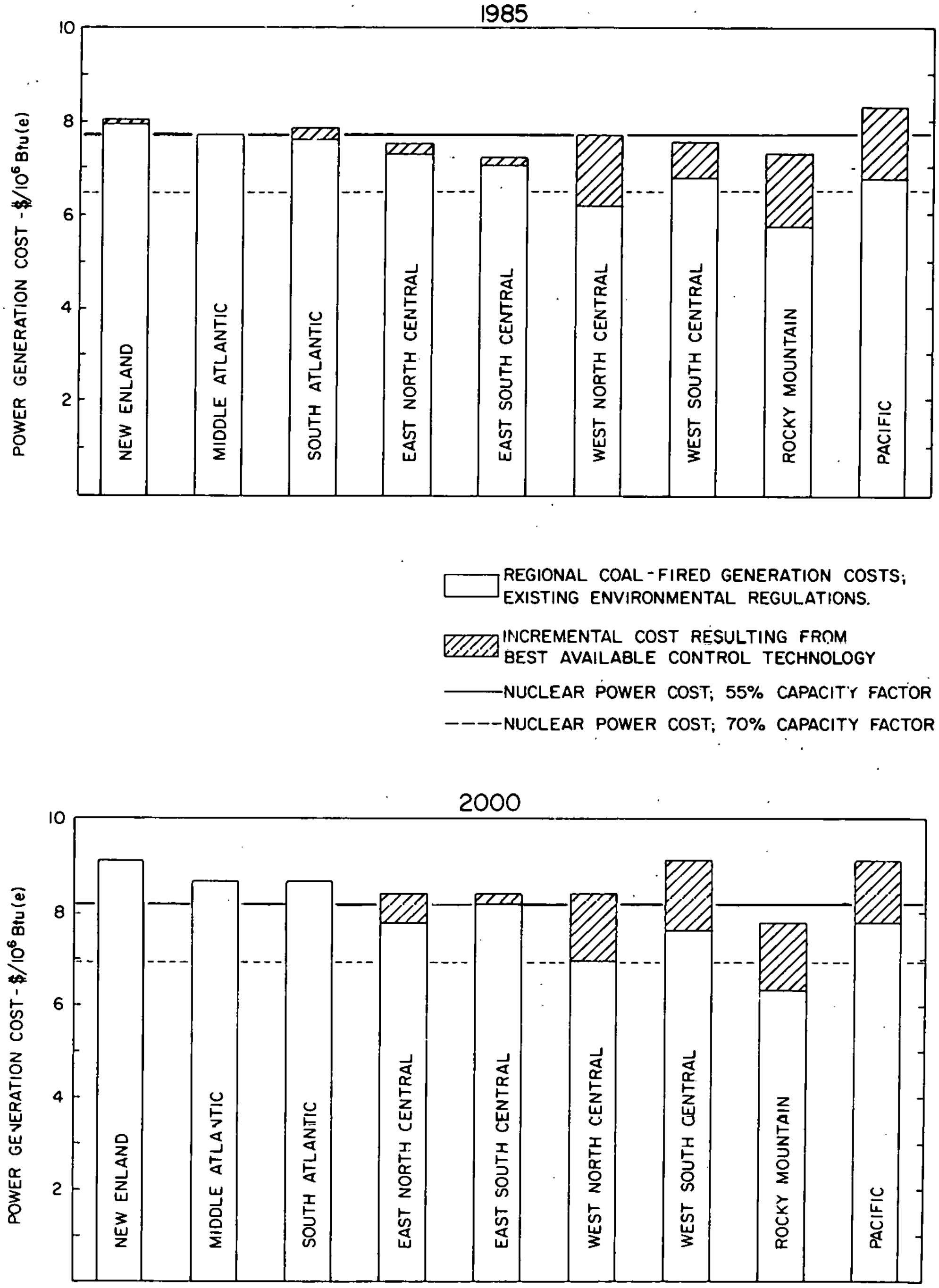

Figure S-2. Comparison of coal-fired and nuclear power costs under existing and proposed environmental regulations.

TABLE OF CONTENTS

(Cont'd)

TABLE OF CONTENTS (CONT'D)

LIST OF TABLES

LIST OF TABLES (CONT'D)

LIST OF TABLES (CONT'D)

LIST OF TABLES (CONT'D)

LIST OF FIGURES

I. INTRODUCTION

This report is the third in a series of interfuel substitution studies in progress in the Energy Technology Assessment Group of the National Center for Analysis of Energy Systems. The first study assessed the potential of electric energy substitution for nonelectric energy forms. The second evaluated specific conservation demand options competing with conventional energy forms for end-use applications. This third study examines the potential role of coal in meeting conventional demands in all consuming sectors. Additionally, the potential for producing synthetic fuels is evaluated in terms of coal production capacity, material, manpower and water requirements and constraints, and regional factors.

Events of the last 10 years have led to a complete reversal in the prospects for coal use during the final quarter of the 20th century. In the early 1960's the introduction of nuclear power coupled with the abundance of low-cost oil from imported sources made coal's future for uses other than metallurgical purposes highly uncertain. Investment in the industry was low, innovation almost nonexistent, and with industrial, residential, and even utility consumers on the east coast converting to oil following the removal of import quotas the industry appeared to have entered an extended period of decline. The passage of the Clean Air Act in 1963 and its subsequent amendment in 1967 and 1970 accelerated this trend. Declining domestic reserves of oil and natural gas tended to go unnoticed due to the availability of inexpensive oil imports and a conviction that nuclear power would provide an increasing share of our electrical generation. The decline in coal usage and the prospect for the industry's ultimate demise was viewed with little concern in most quarters, and with a great deal of satisfaction among environmentalists.

The rapid turn in events since the 1973 oil embargo has forced a reappraisal of coal's contribution to domestic energy production. Growing environmental concerns over the safety of LWR operations, problems with long-term radioactive waste disposal and storage, and the nebulous future of the breeder program have cast a pall of uncertainty over the nuclear industry. These factors, coupled with our vast domestic coal reserves may lead to patterns of coal use substantially different than those recently envisioned. Historically, coal became a significant energy source during the industrial revolution and by 1910 supplied almost 80% of the total energy demand. Today, it supplies less than 20%. Coal production has also been relatively constant since 1910, varying between 500 and 600 million tons per year (640 million tons were produced in 1975). Now, as a result of external forces such as the oil embargo of 1973, the rise in uranium prices and other problems facing the nuclear industry and awareness of potential impending depletion of gas and oil resources, the coal industry is faced with the task of increasing production to approximately one billion tons in 1985 and two billion tons by 2000.

The resource base to meet these goals exists. The U.S. Bureau of Mines estimates that 219 billion tons of coal is economically recoverable from a demonstrated coal reserve of twice that amount. Cumulative production at the projected 4.6% annual growth rate will be 57 billion tons by 2000, or roughly 21% of current economic reserves. It is interesting to note that if this growth rate was maintained beyond 2000, these reserves would be exhausted by 2035, and the total reserves would be consumed by 2050. If production was maintained at 2000 levels, current economic reserves would be exhausted in 2080 and total reserves in 2190. It is highly unlikely, therefore, that resource constraints will enter coal planning deliberations within the next 50 years.

New environmental regulations coupled with the anticipated emergence of new markets for coal (synthetic fuels) are rapidly changing the economics of coal use. Perhaps the most visible example of this has been the rapid increase in demand for western coal. Five years ago, the depressed condition and outlook of the industry were such that bearing the risk associated with opening a western mine and then paying the substantial shipping costs to bring this easily mined, low sulfur fuel to eastern and midwestern markets provided no financial incentive. Recently, however, utilities as far west as New York State have begun planning new generating capacity designed for western coal. A brief examination of the trends behind this switch is instructive.

Coal price trends since 1950 are displayed in Figure 1. While the rapid price increase since 1970 has provided the coal industry revenues desperately needed to modernize operations and to attract investment capital for future expansion, it has added roughly $9 billion to our annual coal bill. Escalating wage demands, the generally low productivity of underground mining operations and rising costs associated with meeting the requirements of increasingly stringent underground mining health and safety regulations are certain to put continuing upward pressures on the cost of eastern coal.

The generally high cost of pollution control, especially for sulfur removal technology, is an additional disincentive to potential users of eastern coal. The FEA has estimated that flue gas desulfurization will add roughly 50¢ per million Btu to the effective cost of high sulfur coal energy to electric utilities by 1985. Eastern coal reserves generally have 1.5-4% sulfur; most low sulfur reserves are captive to the coking industry. For these reasons, and because of the tremendous jump in oil prices, the high costs

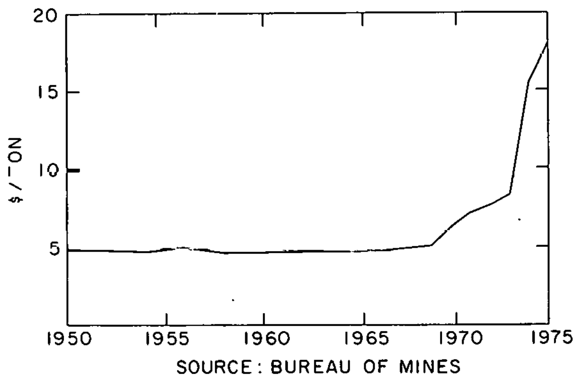

Figure 1. Average U.S. coal prices (FOB Mine) 1950-1975.

of transporting low sulfur, low energy western coal to midwestern and eastern market areas are no longer prohibitive, and a boom in western coal development is underway.

Similarly, the expectation that DOE's synthetic fuels program will result in a commercial coal conversion industry will open this new market for coal. This market may be expected to expand rapidly in the face of dwindling oil and natural gas supplies, if current projections are borne out. These evolutionary trends all suggest that future regional coal use patterns will be radically different from historical trends.

Coal is often viewed as being "end use limited." This perspective arises from the fact that there are few technical constraints on our ability to extract coal and to move it over large distances. Difficulties do arise in particular uses of coal in the various end-use sectors. The following is a matrix of technologies at various stages of development that may remove the current end-use constraints.

End Use	Current Constraint on Use of Coal	Key Technologies
Base load electric	Environmental (sulfur and particulates)	Stack gas scrubbing, fluid bed combustion, fuel cell
Peak electric	Need clean fuel or turbine or fuel cell	Low Btu gasification, clean combustion
Space Heating	Solid fuel is inconvenient	High Btu Gasification
Process Heat	Environmental Need clean fuel for direct firing	Fluid bed combustor Low Btu gasification
Transportation	Solid fuel is inconvenient	Liquefaction
Petrochemicals	Feedstock requirements	Liquefaction

It is apparent that the number of feasible alternatives for satisfying each region's demands for solid, liquid, and gaseous fossil fuels will increase even as the overall availability of these fuels tightens. Consequently, interregional competition for low cost fossil fuels will be expected to intensify during the coming twenty-five years, and a careful investigation of the options each region will have in satisfying its energy needs will shed substantial light on the regional characteristics and impacts of an accelerating rate of coal usage during this period.

A number of regional models for energy supply and consumption patterns are available or are currently under development. The best known of these are FEA's PIES model and the Bechtel Clean Coal Energy (RESPONS) Model. While each of these models offers valuable insight into regional effects (and elements of both are incorporated into the model developed for this study), both were felt to be too global to capture the specific economic alternatives that we believe will underlie this evolution. Accordingly, a much narrower, more cost specific model was developed. Although the problem was formulated as a linear programming exercise, emphasis was placed on developing route-specific costs and alternatives, rather than generating supply and demand curves in a much larger and a more general package. The allocations generated suggest where significant new coal flows might arise; more importantly they expose critical areas where policy changes might be expected to influence these flows. This formulation also provides insight into the regional nature of a developing synthetic fuels industry.

Three runs were generated; a single run for 1985 and two for the year 2000, corresponding to two postulated levels of synfuels development. The major question in applying coal to production of synthetic liquids and gases is economic. Given past and future anticipated increases in fuel prices, can coal conversion processes achieve economic competitiveness with conventional gas and liquid resources? The answer is yes--eventually. Most users of fossil fuels theoretically have the capacity (in the long term) to substitute other fossil fuels or electricity. To do so will involve consideration of a number of financial, environmental, and ultimately, resource constraints. There is little doubt that gas and petroleum, whether domestic or imported, will be depleted long before our coal resource base.

There is also an important noneconomic factor to be considered in dealing with the energy problems. At present approximately 40% of our crude oil needs are being satisfied by imports and the trend is towards higher oil and gas imports in the short and intermediate term. Such heavy dependence on imports makes us very vulnerable to embargoes, such as the one experienced by this country in 1973. Assuming it is desirable to achieve some level of energy self-sufficiency, the United States must either change its demand pattern so that it corresponds more closely to the domestic energy supply or modify domestic energy supply to more closely correspond to the demand pattern. While modification of the demand pattern is possible through conservation and fuel switching, there are some constraints limiting the rate of change. The major limitation is due to the fact that, until recently, major investment decisions were predicated upon inexpensive liquid and gaseous fuels. This has left the country with enormous capital investments that rely heavily upon the inexpensive availability of oil and gas. The capital investment needed to make major changes in homes, industry, and transportation is large and would mean major disruptions if an overly rapid transition were sought. One of the alternatives for the modification of the energy supply is through conversion of coal into liquid and gaseous fuels.

The important remaining question is whether alternative technologies such as nuclear fusion and/or solar will become economically competitive before relatively low cost oil and gas resources are depleted. If so, the long-run prospects for coal will be limited. If not, coal will occupy an increasingly critical role in supporting our economy.

The breeder question will not be addressed in this study, since a variety of sociological, political, and environmental factors have obscured the issue of potential economic viability. However, since this study covers the 1985 to 2000 time frame, and any significant level of breeder reactor penetration into the economy will not occur before 2000, the breeder issue need not affect the conclusions resulting from this analysis. Additionally, although breeder and solar energy have large potential impacts on direct consumption of thermal energy (space and process heat), liquids and gases will still be required for the transportation and petrochemical feedstock sectors, barring an unanticipated revolution in transit patterns.

Regardless of the penetration of other technologies, coal will be a vital factor in the U.S. energy system in the time frame of the present to the year 2000 and beyond.

Coal mining productivity has been declining, however, and large capital outlays and significant lead time will be required to bring new mines into production. Mine operators will require assurances, possibly in the form of long-term contracts, that investments made to increase production will provide adequate returns. Environmental factors, both in mining and combustion of coal, also require consideration in view of potential health effects, public awareness, and mandated environmental emission levels. It is assumed that the urgency of maintaining dependable energy supplies will lead to a resolution of these uncertainties which will be environmentally acceptable, and provide the economic incentives required to increase production to the required levels.

The analysis to be described assumes a prescribed level of coal production in 1985 of roughly one billion tons, based on FEA[1] estimates. This is broken down by costs, production estimates, special application coal (i.e., coking), heat content, and two ranges of sulfur content (high and low) as a function of producing region. Low sulfur coal is defined here as coal which can be burned in utility boilers without stack gas scrubbers to meet current Federal New Source Performance Standards (NSPS).

Eight producing regions were chosen, of which two produce only high or low sulfur coal. Thus, fourteen potential coal supply types are possible (exclusive of metallurgical coal) from the eight producing regions. Characteristic energy contents were assigned to each coal type, as well as a cost in 1975 dollars adopted from FEA estimates. These production rates and costs were extrapolated to the year 2000 at estimated real cost increases and production growth rates. The nine census regions were selected for disaggregating regional energy demands.

Thus, the analysis consists of obtaining the least cost solution for transportation of coal from eight supply to nine demand regions. It should be noted that, although metallurgical grade, or "coking" coal is included in the supply estimates, it is not considered in the analysis, but is subtracted from the total supply; therefore, the remaining coal is available for burning by utilities and industry, or for conversion to synthetic fuels. The resulting analysis considers not only the regional nature of supplies, with characteristic (and different) energy content and different costs, but also accounts for regional demands by fuel type. Thus, this study contains a degree of regional resolution which is not captured by conventional national level analyses of energy supply and demand relationships.

II. DEVELOPMENT OF FUTURE REGIONAL ENERGY SUPPLIES AND DEMANDS

A. Introduction

Domestic energy supply estimates were prepared regionally for each fossil fuel for the years 1985 and 2000. Regional coal production forecasts were adopted from recent FEA data for 1985[2] and were estimated for 2000 by extrapolating regional growth rates for the 1985-1990 period developed in the Project Independence Report.[3] All other supply and demand estimates were based upon work performed at BNL[4] under a program for the Electric Power Research Institute (EPRI).

Under this program, a series of Reference Energy Systems (RES) was developed for 1980, 1985, and 2000 for each of the nine census regions, as well as for the U.S. summarizing the regional estimates. An RES is a network representation of the technical activities required to supply various forms of energy to end-use activities. Technologies are defined for all operations involving specific fuels including their extraction, refining, conversion, transport, distribution, and utilization. Each activity is specified by a link in the network containing an associated efficiency. The RES's were formulated with minimal introduction of new technologies, and projections for future years were derived from data available in the various sectors. The national RES's summarizing the regional data are shown in Figures 2 and 3 for 1985 and 2000.

The rationale for adopting a different source for the coal sector was that FEA's projections were aggregated from the Bureau of Mines supply districts which link coal type to their geographic locations. Additionally, since the PIES model was developed to derive regional market-clearing prices, these estimates formed a good basis for exposing energy transportation and technology

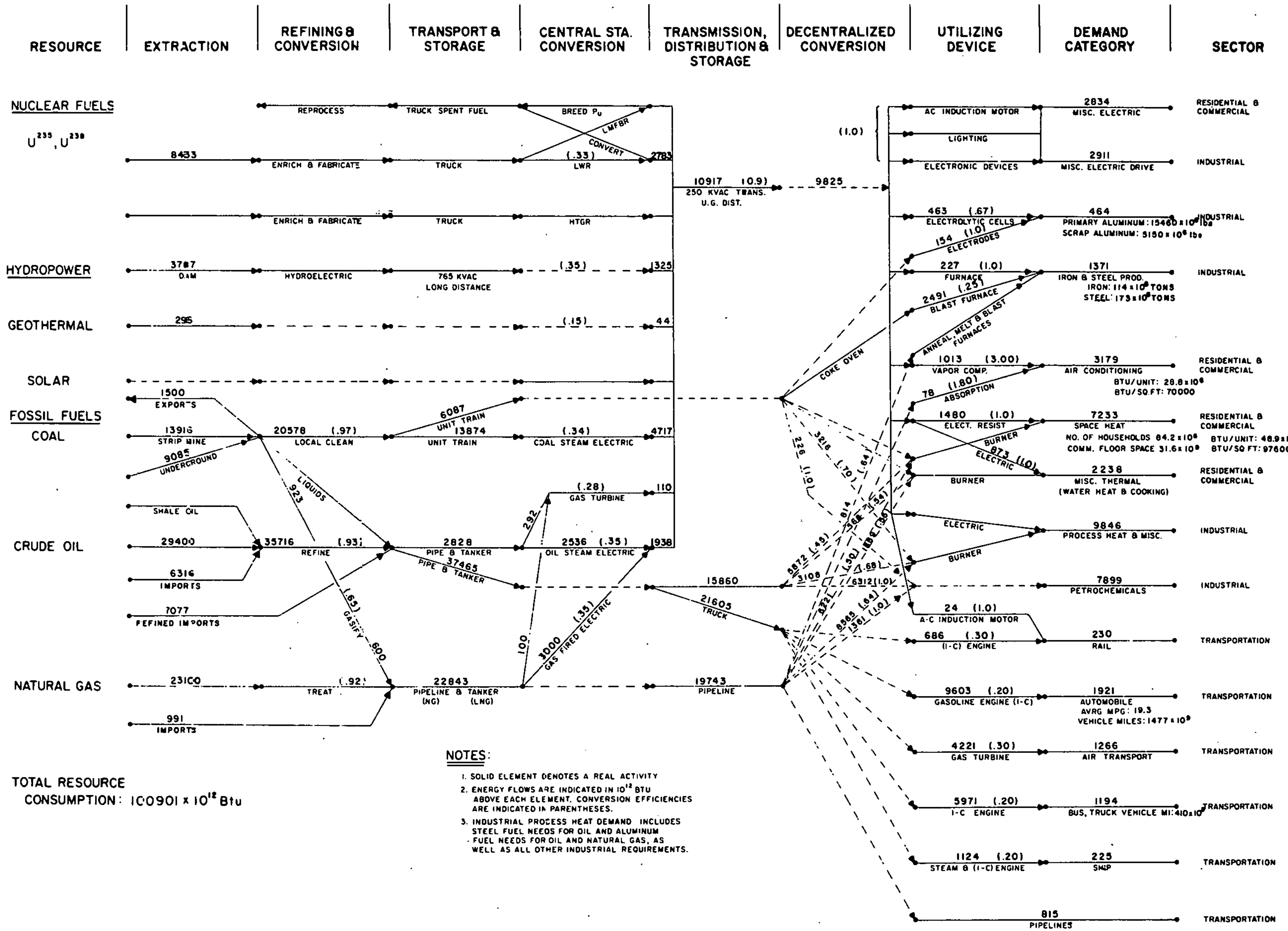

Figure 2. United States Reference Energy System, Year 1985.

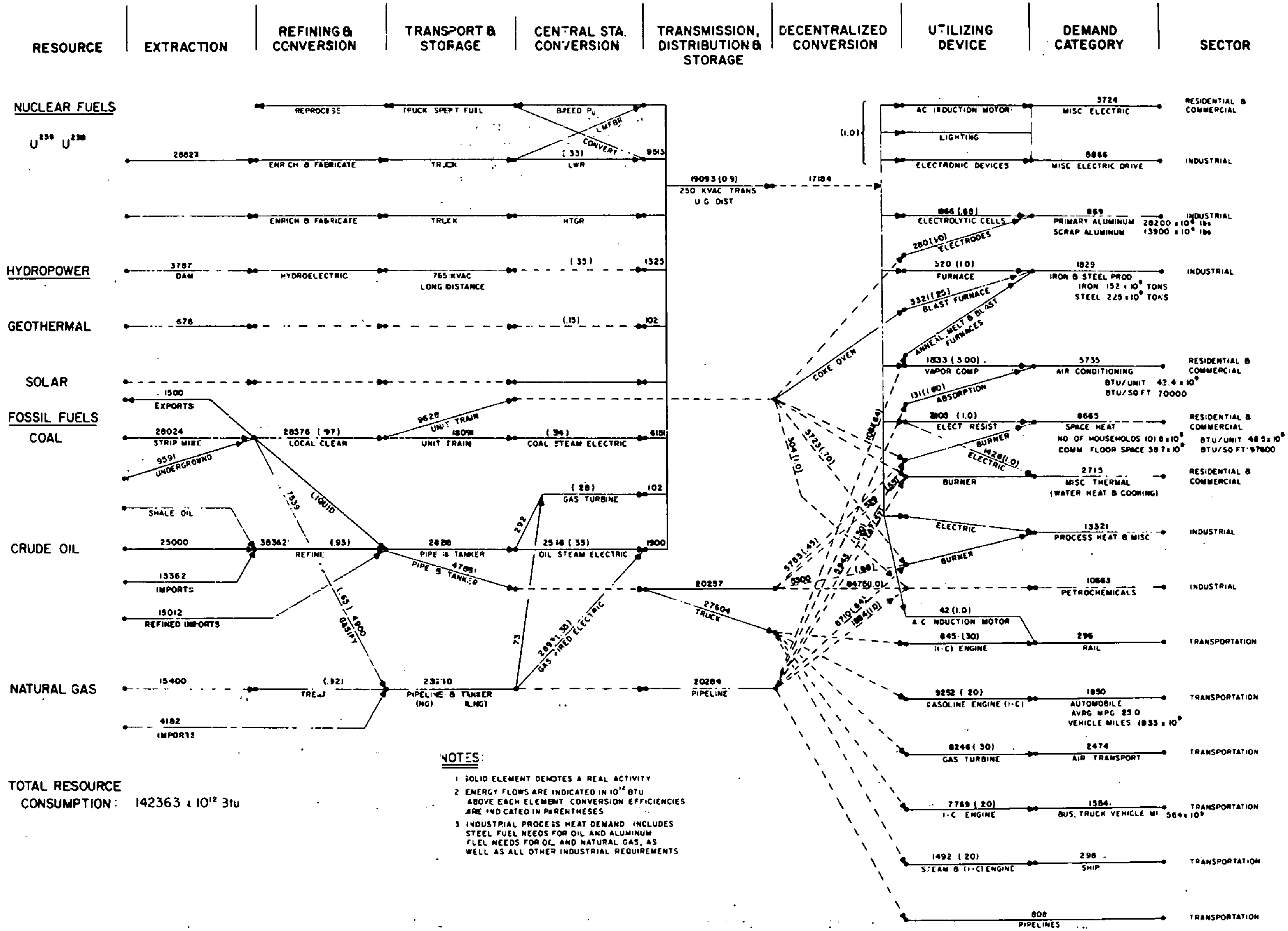

Figure 3. United States Reference Energy System, Year 2000.

alternatives. This approach allowed a familiar and consistent set of coal prices to be used as the basis for exposing transportation alternatives. Accordingly, the output of this model should not be thought of as an absolute regional activity projection for coal utilization (although these are generated), but rather as a means of understanding how fundamental cost variations in the supply and transportation of different energy forms can be expected to influence what these regional markets will look like. This approach, while perhaps less elegant than others, was felt to be more valuable from the perspective of exposing those options where federal and/or regional and state policy could be expected to have the greatest leverage on affecting the pattern and level of coal utilization.

B. Coal Supply

The U.S. coal fields were aggregated into eight coal supply regions, as shown in Figure 4. Within each of these regions, the coal is of similar rank and heating value, although more specific characteristics vary broadly. Following the FEA PIES formulation, future coal supplies were divided into metallurgical, low sulfur ($\leq$ 0.6 lbs S/10^6 Btu) and high sulfur fractions. As stated previously, metallurgical coal was not modeled due to the specialized nature of the coking/steel industry.

Broadly speaking, the two Appalachian regions are made up of high rank bituminous and authracite reserves. The North Appalachian region coals generally have sulfur contents ranging between 1.5-3 weight percent, while the Southern fields typically run between 0.5-2% sulfur, including most of the nation's coking reserves. Roughly 65% of Appalachian production was from underground operations in 1973,[5] and this percentage is expected to increase as the strippable reserves are depleted. The Appalachian fields are

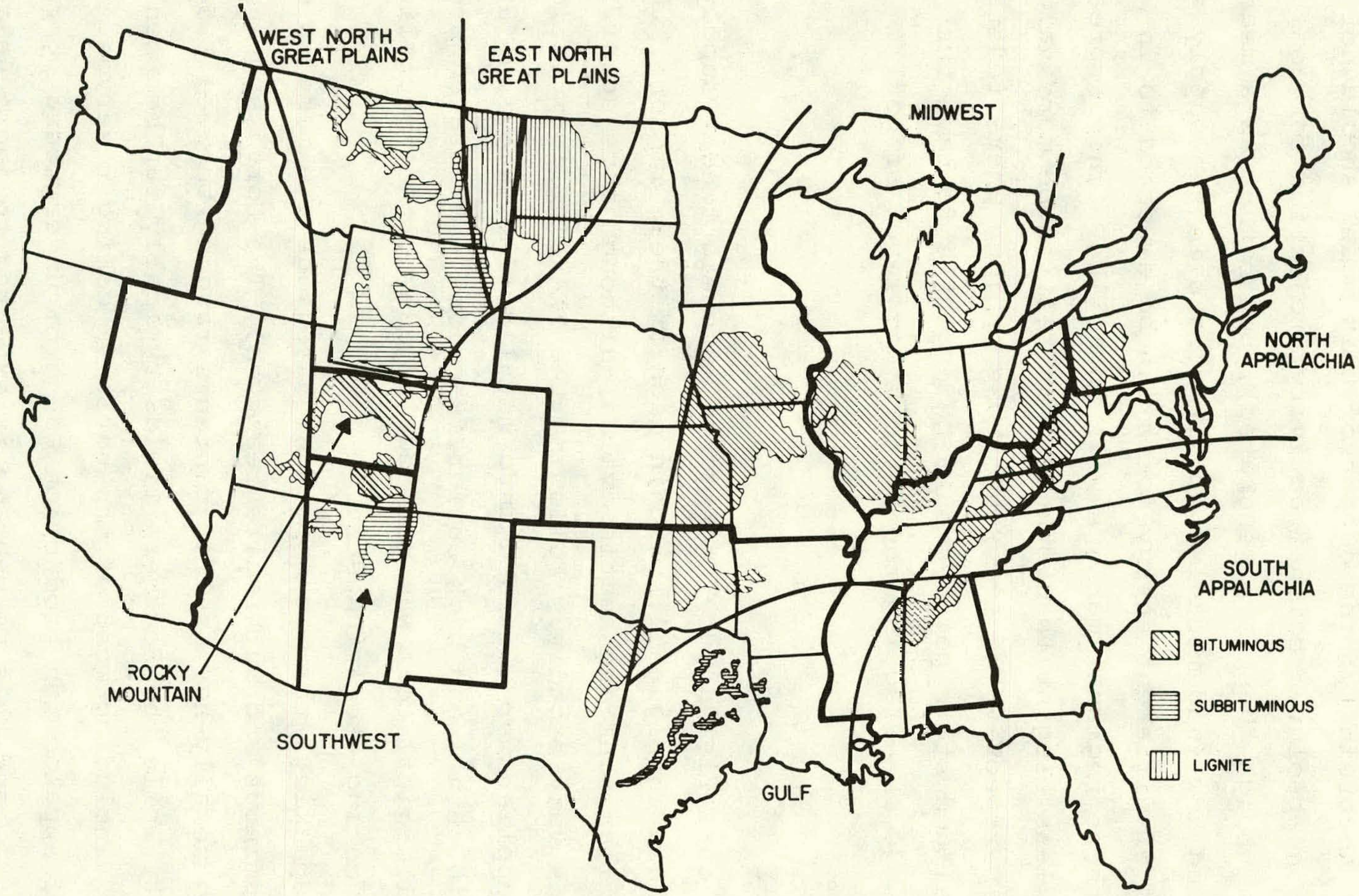

Figure 4. Coal supply regions.

characterized by thin seams (generally 3-7 feet thick) and have been mined mainly by traditional room and pillar techniques, although continuous mining operations are becoming more common. Mining costs are typically among the highest in the country in Appalachian mines.

The Midwestern and Gulf regions are characterized by coals of relatively high (2-4%) sulfur content. Of the two, the Midwestern field is by far the more important, producing roughly 150 million tons in 1973. This coal is a low rank bituminous coal, typically in 3-6 ft. seams, with heating values between 10-15 percent lower than Appalachian bituminous coals. These seams are generally closer to the surface than Appalachian seams and 60% of 1973 production was strip mined.

The Western coal region is made up of fields of a broad variety of coal types ranging from low energy lignite of the Fort Union (N.D.) region to high rank bituminous reserves in western Colorado, similar to Southern Appalachian coals. Most of this coal is low in sulfur and occurs in thick, easily accessible seams. With the exception of certain bituminous reserves in Colorado and Utah, western coal is noncaking. These characteristics make western coal particularly attractive to electric utilities, and utility consumption of western coal more than tripled between 1970-1975, rising from roughly 25 to 78 million tons during this period. Utilities as far east as upstate New York are currently planning coal-fired boilers designed for western coal. Recognizing that there are a host of unresolved issues of public and environmental policy, it is nevertheless almost inconceivable that western coal reserves will not continue to be developed at a very rapid pace during the next 10-15 years.

The East North Great Plains (ENGP) region consists of low-Btu, extremely low (0.4-0.8%) sulfur lignite. While ENGP reserves generally range between 5 to 20 feet thick and will ultimately be mined mainly by underground methods, almost 13 billion tons of strip minable reserves currently exist, and these will undoubtedly be developed first. While the low sulfur and ash characteristics of ENGP coal make it an attractive boiler fuel, its low heating value and high moisture content will increase its delivered cost to distant markets relative to other Western coals, thereby limiting its potential geographic distribution.

The West North Great Plains (WNGP) and Southwest regions contain subbituminous coal reserves ranging between 8000 to 9500 Btu/lb. The WNGP region contains vast reserves of low sulfur coal in beds ranging from 10 to almost 100 feet thick. Most of these reserves are strip minable and extraction costs are expected to be among the lowest in the country. These factors encourage large-scale mining operations; mines in Montana and Wyoming are among the nation's largest. For example, the Decker mine, located in Southeastern Montana, is currently the largest coal mine in the country; producing nearly 10 million tons in 1975, the mine is expected to expand to a rate of roughly 14 million tons by 1978.[6]

Finally, the Rocky Mountain region, located in western Colorado and eastern Utah, contains substantial reserves of low sulfur bituminous and metallurgical quality coal. Seams typically range between 2 to 5 feet thick and are heavily faulted and folded. Most of these reserves will require underground mining, so it is expected that metallurgical production will expand much more rapidly than that of nonspeciality coal due to its substantially higher market value in expanding domestic and export coking markets.

FEA 1985 supply projections for these coal regions are presented in Table 1 and BNL supply estimates for 2000 are shown in Table 2. As will be discussed later, in developing the accelerated

TABLE 1

1985 Coal Supply [1]

Supply Region	Type[2]	Average Heat Content (Btu/lb.)[3]	Production (10^6 Tons)	Cost ($/Ton)	(FOB Mine)[4] ($/$10^6$ Btu)
Northern Appalachia	MET	13,600	20.3		
	LS	12,300	15.2	24.90	1.02
	HS	12,300	147.1	12.90	.53
Southern Appalachia	MET	14,100	111.9		
	LS	12,400	149.6	24.20	.98
	HS	12,400	61.1	12.80	.52
Midwest	LS	11,000	14.2	22.80	1.04
	HS	11,000	150.9	10.80	.49
Gulf	HS	7,000	20.6	4.80	.34
East North Great Plains	LS	7,000	25.2	6.30	.45
	HS	7,000	6.1	4.40	.31
West North Great Plains	LS	8,900	251.2	4.90	.28
	HS	8,900	6.1	3.80	.21
Rocky Mountain	MET	13,000	6.1		
	LS	12,000	12.7	10.00	.42
Southwest	LS	8,900	7.7	8.00	.45
	HS	8,900	12.9	4.40	.25
U.S. TOTAL	MET		138.3		
	LS	10,150	475.8	12.40	.61
	HS	11,320	404.8	11.15	.49
		10,690[5]	1018.9	11.83[5]	.56[5]

[1]Adopted from 1976 Federal Energy Outlook, Tables IV-28 and IV-37.

[2]MET: Metallurgical quality coking coal.
LS: Complies with current NSPS for sulfur (.6lb.S/10^6 Btu).
HS: High sulfur coal; i.e., S> .6 lb/10^6 Btu.

[3]Adopted from "Project Independence Blueprint: Coal Task Force Report", Table 2.

[4]All costs are in 1975 dollars.

[5]For non-metallurgical coal.

TABLE 2

2000 Coal Supply

Supply Region	Type[1]	Average Heat Content (Btu/lb.)[3]	Production (10^6 Tons)	Cost ($/Ton)	(FOB Mine)[4] ($/$10^6$ Btu)
Northern Appalachia	MET	13,600	27.4		
	LS	12,300	20.6	31.10	1.26
	HS	12,300	198.7	16.10	.66
Southern Appalachia	MET	14,100	183.3		
	LS	12,400	245.1	30.20	1.22
	HS	12,400	100.1	16.00	.65
Midwest	LS	11,000	19.0	28.50	1.30
	HS	11,000	192.4	13.50	.61
Gulf	HS	7,000	87.2	6.00	.43
East North Great Plains	LS	7,000	39.3	7.90	.56
	HS	7,000	9.5	5.50	.39
West North Great Plains	LS	8,900	601.9	6.10	.34
	HS	8,900	14.7	4.80	.27
Rocky Mountain	MET	13,000	28.8		
	LS	12,000	15.2	12.50	.52
Southwest	LS	8,900	19.8	10.00	.56
	HS	8,900	33.1	5.50	.31
U.S. TOTAL	MET		239.5		
	LS	9,880	960.9	13.48	.68
	HS	10,860	635.7	12.94	.60
		10,270[5]	1836.1	13.26[5]	.65[5]

[1]
MET: Metallurgical quality coking coal.

LS: Complies with current NSPS for sulfur (0.6 lb. S/10^6 Btu).

HS: High sulfur coal; i.e., S> .6 lb/10^6 Btu.

[3]Adopted from "Project Independence Blueprint: Coal Task Force Report",

[4]All costs are in 1975 dollars.

[5]For non-metallurgical coal.

synfuels case (9 quads total), it was necessary to increase coal supplies by roughly 15% in each producing region.

C. Oil and Natural Gas Supply

The location and supplies of domestic oil and natural gas will have an increasing impact on coal consumption patterns during the coming 25 years. While there exists considerable uncertainty (and spirited debate) about what stimulative impact, if any, a relaxation of federal regulatory policy might have on production, the fact remains that domestic production of these fuels has declined in recent years in the face of steadily rising demand and prices. The result of this has been increasing curtailment of natural gas supplied to "interruptible" customers and a steadily increasing reliance on imported oil. If these trends continue (as they are expected to), the shortfall of these sources will have to be met by some combination of conservation measures, fuel switching to coal, development of an expanding synthetic fuels industry, new Alaskan oil and gas production, the discovery and development of new fields (such as an Atlantic OCS find), and/or increasing imports of oil and LNG.

While most regions of the country produce small quantities of oil and gas, the bulk of our domestic production currently originates in the fields indicated in Figure 5, and is distributed to other regions either through oil tankers or through the principal oil and gas piepline arteries indicated.

Current production and supply projections for 1985 and 2000 are presented in Table 3.

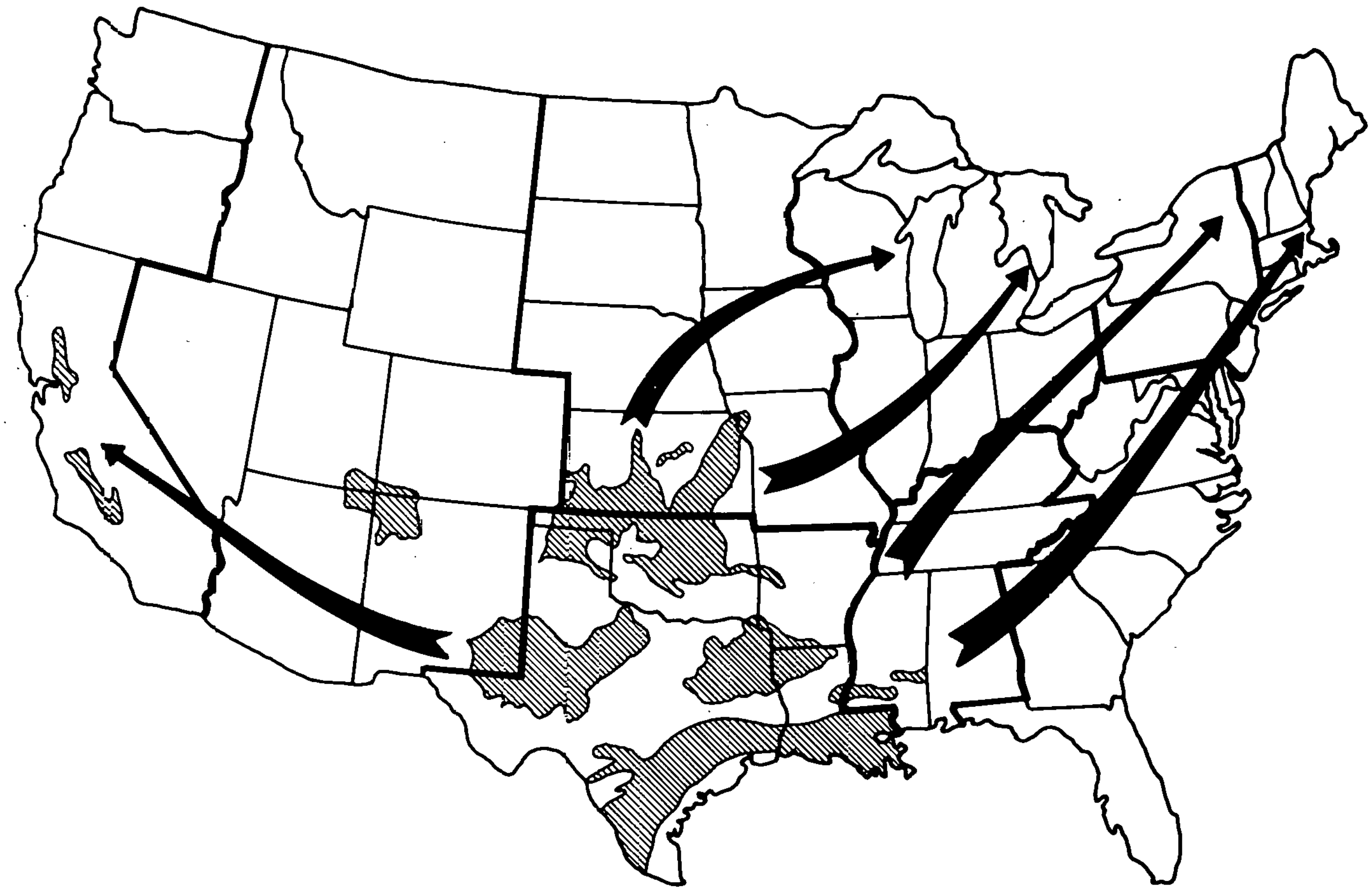

Figure 5. Lower 48 oil and gas fields and principal pipeline arteries.

TABLE 3

Current Regional Production
and Future Supply Projections
for Domestic Oil and Natural Gas
(10^{12} Btu/yr)

	1972	1985	2000
OIL SUPPLIES			
New England	0	98	83
Mid Atlantic	27	115	98
South Atlantic	117	200	173
East North Central	384	324	285
East South Central	488	409	360
West North Central	750	631	555
West South Central	16685	15409	13210
Rocky Mountain	2292	1910	1680
Pacific	2575	5400	2310
North Slope		4300	4300
Atlantic OCS*			590*
Total	23318	28796	23644
NATURAL GAS SUPPLIES			
New England	0	0	0
Mid Atlantic	79	85	98
South Atlantic	237	213	154
East North Central	126	128	92
East South Central	173	170	123
West North Central	894	808	586
West South Central	18313	16747	12135
Rocky Mountain	1728	1572	1140
Pacific	606	1500	400
North Slope		1000	1000
Atlantic OCS			700*
Total	22154	22223	16428

* Potential supply - no proven resource.

III. FUTURE COAL MARKETS

Figure 6 displays the vast change in markets that the coal industry has experienced following the Second World War. The electric utility industry has become the dominant market for domestic coal and is expected to maintain this position throughout the foreseeable future. On the other hand, regional demands for energy in general and coal in particular will influence future coal consumption patterns. An understanding of the coal requirements for each type of coal market in a national aggregate sense and an investigation of the alternatives for satisfying these generic requirements at a regional level is an essential prerequisite for estimating the impacts of an accelerated coal use program.

The advantage of addressing this type of analysis from a regional and market differentiated approach stems from the nature of the coal industry. On the supply side, there exist certain characteristics of different coals which make them suitable for certain uses while unacceptable for others. Certain mineral and rank characteristics, for example, are essential for coke manufacture; at the same time, a number of the developing synthetic fuels processes will require expensive pretreatment processes to destroy any caking properties of their coal feed.

Regional variations in transportation availability make particular coal sources either more or less attractive than their geographical separation alone would suggest. The New York utilities (Niagara Mohawk and Rochester Gas & Electric) planning to burn western coal both intend to capitalize on their proximity to the Great Lakes for transporting the coal, thereby reducing their shipping costs relative to the all-rail alternative.

On the demand side differing environmental regulations for different classes of users create preferences peculiar to each

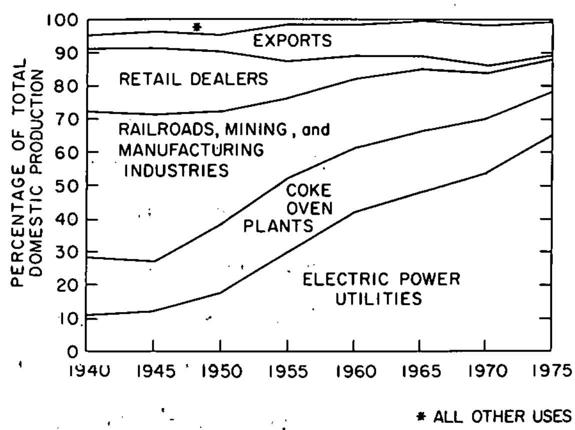

Figure 6. Market composition for U.S. coal production (1940-1975).

user type. The most obvious example of this is the difference in standards for allowable SO_2 emissions from utility and small industrial boilers. All of these factors recommend segmentation of coal markets as finely as possible, both geographically and by user classification.

The other side of the coin, of course, is the considerable uncertainty associated with projecting the future behavior of any complex system. The energy future of the U.S. is fraught with political, economic, legal, technological, and environmental uncertainty, and increasing disaggregation increases these uncertainties exponentially. The approach taken in this study was to address the problem at a regional scale which would allow gross distinctions to be made in supply, transport and demand options, and to segment coal demand into markets which could be distinguished based on generalizations concerning chemical properties demanded, consumer tonnage requirements (to determining available transportation options), and distinguishing environmental regulations.

Having made these distinctions, an effort was made to estimate the relative costs of supplying each user class in each region. The coal, oil, and gas supply was formulated as a cost minimizing transportation problem, constrained by projected regional supplies and demands. This formulation is clearly simplistic to the extent that it assumes the existence of perfect competitive markets, giving all parties free access and equal bargaining power in the market; its strength, as previously mentioned, lies in its ability to expose the competitive process, and to identify the equilibrium towards which the (imperfect) market might be expected to ideally drift.

The remainder of this section describes the differentiation of the selected regional demand sectors (i.e., the various regional markets for solid, liquid, and gaseous fossil energy) and presents their projected demands for 1985 and 2000. The next chapter develops the transportation links (and costs) connecting each of these demands to its feasible supply options, and Chapter V ties the basic energy extraction costs, the transportation costs, and any environmental control costs together, developing cost estimates for each supply/demand link and presenting the resulting cost-minimizing consumption patterns for each of the three scenarios.

Four types of consumers can be expected to dominate domestic coal markets: electric utilities, industrial plants, coal conversion plants, and coking plants. As mentioned previously, coking requirements are so specialized that coal meeting coking specifications is either captive to the steel industry or sold at such high premiums that it is unlikely that substantial amounts of this coal could be diverted to other markets.

The utility industry operates under increasingly stringent environmental standards, but each plant has large enough annual rerequirements that utilities can take advantage of substantial transportation economics of scale, allowing utilities to ship high quality coal from distant mines at low cost by unit trains, barges, and coastal colliers.

Industrial users tend to have lower volume requirements, thus reducing their transportation options, but operate under less stringent environmental constraints which allow them greater latitude in obtaining acceptable coal. Finally, the coal conversion industry can be expected to have volume requirements similar to those of electric utilities. Coal retorting tends to convert feed sulfur to H_2S, for which well-developed control technologies exist. Accordingly, the coal conversion industry should not have a strong preference for low sulfur coal.

While these requirements are quite general, they allow certain decision rules to be formulated which are not unreasonable at a regional level of aggregation.

First, in regions where there is little low-sulfur coal, (i.e., the Midwest and Appalachian regions) electric utilities will bid up the price of available supplies to just under their estimated cost of flue gas desulfurization (FGD). Industrial users and coal conversion plants will be largely indifferent between coals of different sulfur content, responding solely to the supply price.

A major force behind the increased interest in low sulfur western coal has been the EPA's sulfur dioxide emission standards for large fossil-fired boilers. For new coal-fired power plants, and prior to the passage of the Clean Air Act amendments, this standard limited allowable SO_2 emissions to 1.2 lbs. SO_2 per million Btu heat input. A number of promising synfuel and advanced combustion technologies are currently under development. A discussion of these options and their current status are presented in Appendix A.

Thus, utilities usually had only two alternatives: stack gas scrubbing or the use of low sulfur coal. A third option, mechanical coal washing may be used in a limited number of instances, but was not considered at the regional level of aggregation we are considering here.

Flue gas desulfurization involves the reaction of SO_2-bearing stack gasses with a sulfur sorbent, inducing a series of chemical reactions to remove the sulfur from the stack gas and either converting the sulfur to some marketable commodity or disposing of the sulfur-bearing sludge in a landfill operation. The process is costly, and, at present, tends to be quite unreliable, particularly when higher concentrations of SO_2 are involved. The most serious problems center around the erosion and plugging of the scrubbers' mechanical parts, and also in consolidating the slurry into an acceptable landfill material.* Scrubbers contribute to increased capital and O&M expenses, and their downtime lowers the availability of the entire plant.

There is no dispute that FGD increases the cost of coal-fired power generation, but there is a wide diversity of opinion as to how much of an increase it actually is. Specific plant operating experiences have ranged between 3 and 13 mills/kWh.(7) It further appears likely that further development work on scrubbers will tend to lower the cost somewhat, but, once again, it is impossible to be definitive and individual plants will undoubtedly vary widely.

In their 1976 National Energy Outlook, the FEA placed a 50¢/ million Btu scrubbing surcharge on high sulfur coal. To check this estimate, we assigned a $100/kW construction fee for scrubber installation, estimated a 2 mill/kWh cost for scrubber maintenance, materials and landfill costs, assumed that the scrubber would increase the net plant heat rate by 400 Btu/kWh and assumed that the scrubber would lower the plants' capacity factor by 5%. Our estimate, thus prepared, checked out within 10% of the FEA estimate. We concluded that the charge FEA used was quite reasonable and incorporated it into our own estimates as a premium paid to producers of low-sulfur coal, exactly as FEA did in their PIES methodology.

The second "rule" applied is that the large volume requirements of utility and conversion plants will allow these consumers to take advantage of the most efficient (i.e., least costly)

---

* See, for example, W. G. Storer, "Operational Status and Performance of the Commonwealth Edison Will County Limestone Scrubber," in EPA "Proceedings:" Symposium on Flue Gas Desulfurization, New Orleans, March, 1976.

transportation modes. Cost considerations will dictate that coal conversion be done at or near the minemouth to take advantage of the substantially lower unit costs of transporting their finished products. Noncoking industrial users as a group will be forced to rely on more costly modes such as spot rail or truck shipments.

The regional disaggregation selected for all energy demands are the nine census regions shown in Figure 7. For the purposes of estimating transportation costs, all fuels except low-Btu gas were assumed to be consumed at the centroidal cities indicated in the Figure. Low-Btu gas was assumed to be consumed near the minemouth, due to the high costs of transporting this fuel substantial distances in pipelines.

Current consumption and regional demand estimates for the different fossil fuel types are presented in Table 4 for 1972, 1985, and 2000. Each region's energy consumption in all consuming sectors was adopted from a BNL study performed for the Electric Power Research Institute (EPRI), with energy demand and supply projections made for various years to 2000.

With the demand estimates now in hand, the next Chapter identifies the available supply alternatives and describes the methodology by which transportation costs were estimated.

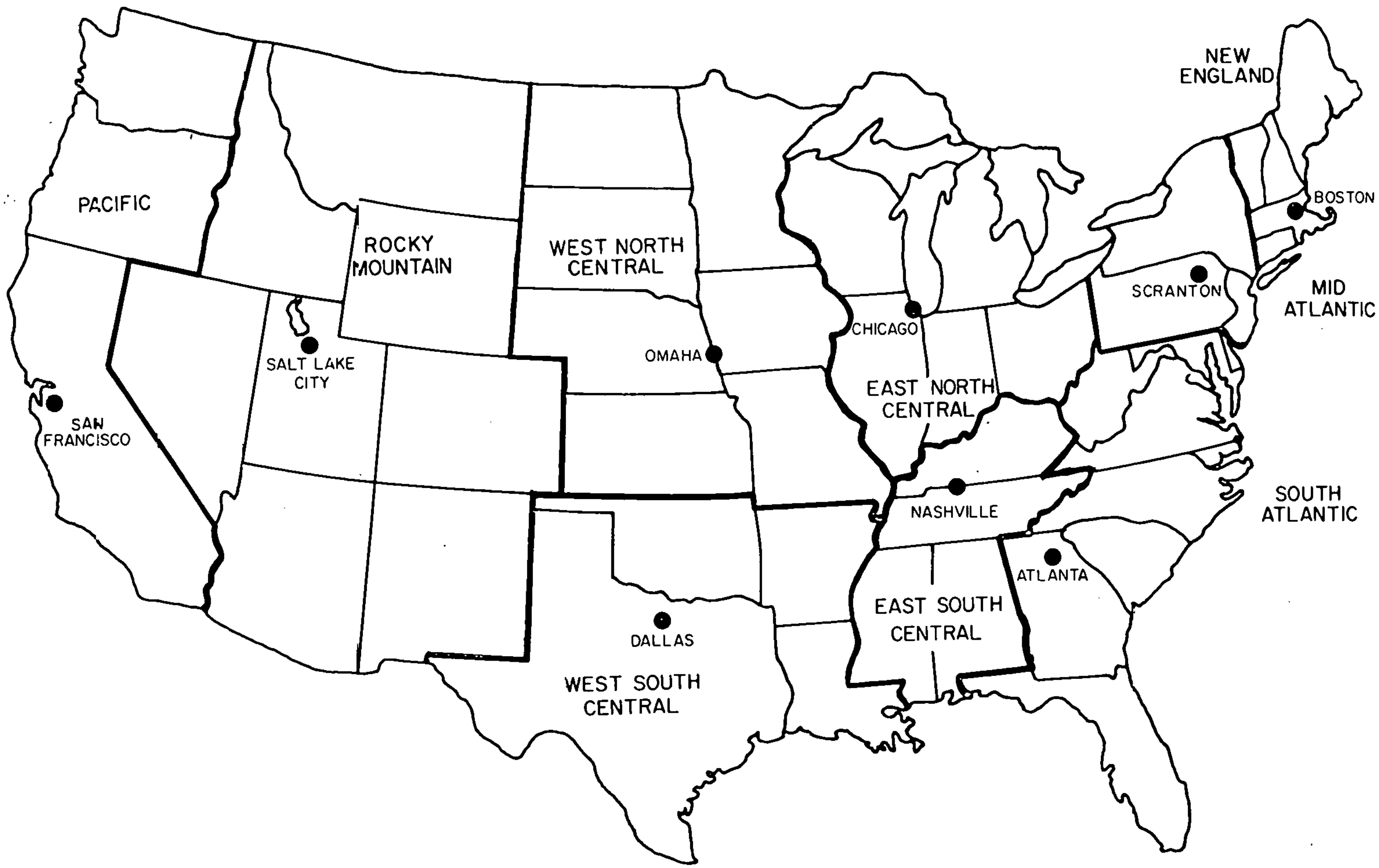

Figure 7. Census regions and demand centroids.

Table 4

Regional Fossil Fuel Demand*
(10^{12} Btu/yr)

	1972				1985				2000			
	Coal				Coal							
	Utility	Industrial+	Oil	Gas	Utility	Industrial+	Oil	Gas	Utility	Industrial+	Oil	Gas
New England	31	10	2912	300	88	34	3545	253	128	52	3942	237
Mid Atlantic	972	493	6554	2097	2343	602	7630	1910	3609	877	9029	1755
South Atlantic	1638	351	5565	1751	2684	512	6924	1552	3207	895	9033	1422
East North Central	2986	977	5669	4660	3858	1218	7833	4554	4200	1840	9621	4374
East South Central	1312	54	1578	1363	1539	343	2169	1486	1751	588	2748	1579
West North Central	622	182	2492	2247	1631	276	3113	1846	2432	477	3828	1780
West South Central	53	34	3194	6543	772	284	4658	7099	1196	854	6429	7886
Rocky Mountain	463	63	1391	1273	745	97	1946	1291	965	210	2593	1313
Pacific	6	51	3994	2384	212	90	5513	2857	600	240	7288	2908
U.S. TOTAL	8083	2215	33348	23218	13872	3456	43331	22473	18088	6033	54511	23254

*All energy quantities are raw fuel equivalent.
+Excludes coke consumption.

IV. ESTIMATING ENERGY TRANSPORTATION COSTS

As the mined cost of coal has risen in recent years, large coal users have begun looking to more distant suppliers for their requirements. Their ultimate objective clearly is to satisfy their energy requirements at the lowest possible cost. These costs will have three components: the cost of extracting the coal, the cost of transporting it, and finally, any extraordinary costs associated with utilizing it (e.g., the cost of pollution control). The previous chapter laid out the constraints and transportation requirements distinguishing the electric utilities, industrial coal users, and the emerging synthetic fuel industry. This chapter will examine the transportation alternatives available within each region for each user type and will develop route-specific costs for each feasible transportation link in an attempt to cost out each option as realistically as possible.

A. Electric Utility Coal Transport

Coal-fired electric utility plants may be thought of as point demands for coal typically consuming between 2 to 5 million tons annually. As utility boiler design technology has become more sophisticated, it has become increasingly difficult for utilities to switch their operation between different fuels. Plants typically have service lives of 30 to 40 years, and the cost of having a plant shut down due to the use of an inappropriate feedstock or simply the inability to purchase coal provides a powerful incentive for utilities to enter into long-term contracts with suppliers. Several large utilities own and operate coal mines to minimize their costs.

From the coal producer's standpoint, a long-term supply contract with a utility provides his revenues with a stability that allows him to enter credit markets easily for capital expansion or renovation funds necessary to the continued operation of his firm. Needless to say, there are both utilities and mine operators who deal strictly in the spot market, but the majority on both sides deal mainly in the contract market, entering the spot market only if an unusual opportunity presents itself or if unforeseen circumstances force them to.(8)

If the power plant is not located at the minemouth, the availability of low-cost and reliable transportation connecting the two is essential. The one modc available almost everywhere is by railroad shipment; depending on the route, river barges or the Great Lakes via coastal colliers may provide a feasible option for part or all of a shipment.

Most major domestic railroads derive substantial portions of their revenues from coal and will custom tailor unit train rates for each shipment, based on such factors as the annual tonnage, distance of the haul, the amount of rail congestion the unit train will create, and on the availability of alternate modes and/or coal sources. Contracts are written from one extreme of the railroad owning and operating the train to the other, where the railroad simply leases the use of its track, with the utility or coal supplier bearing all other expenses. All of these elements enter into the bargaining process along with the careful appraisal by each party of how much the other is willing or able to concede.

The cost functions used for 1985 are presented in Figure 8. The relative competitive positions of the various modes are not expected to change so these costs were escalated uniformly at an effective rate of 2.5% annually to generate estimates for 2000. Regional coal costs were escalated at a lower 1.5% rate, reflecting the belief that abundant supplies of easily mined western reserves will restrain coal price escalation.

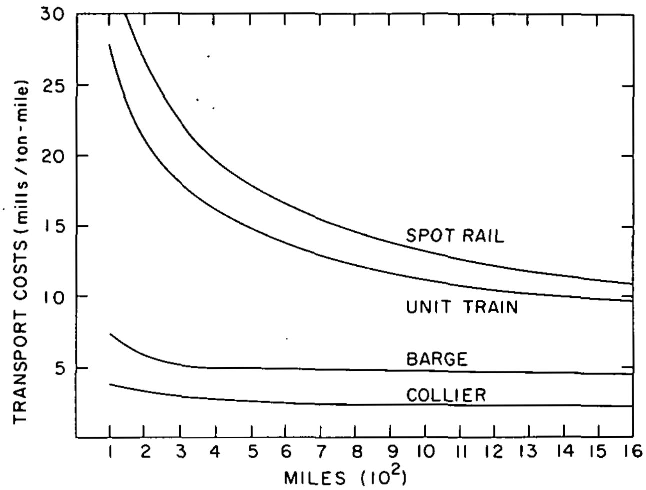

Figure 8. Estimated 1985 coal transport costs (1975 $).

In order to estimate the costs of transporting regional coal supplies, supply centroids were selected for each region:

Coal Supply Region	Centroid
North Appalachia	Pittsburgh, Pa.
South Alpalachia	Huntington, W. Va.
Midwest	Springfield, Ill.
Gulf	Houston, Tex.
East North Gr. Plains	Bismark, N.D.
West North Gt. Plains	Casper, Wyo.
Rocky Mountain	Grand Junction, Colo.
Southwest	Gallup, N.M.

Rail haul distances were estimated from the Rand McNally Railroad Atlas[9] and waterways distances from the Inland Waterways Mileage Guide.[10]

Similar uncertainties exist in attempting to estimate spot rail, river barge, and coastal collier rates. As a general rule, transportation costs are likely to be lowest where intermodal competition is present and highest where a single carrier has the market "in his hip pocket."

The transportation cost estimates used in this study were developed by the Bechtel Corporation in its RESPONS model.[11] Several adaptations were made to more accurately model real world costs. Coastal colliers once supplied a substantial portion of the Atlantic Coast's coal needs so several routes were investigated for shipping coal in unit trains from the Appalachian fields to docks at Philadelphia, Baltimore and Hampton Roads, and Virginia for transshipment to coastal carriers bound for New England. The Southern Appalachia to Hampton Roads to New England route turned out to be slightly less costly than an all unit train shipment, and also bypassed the deteriorating track of the Northeastern Railroads.

All coal transshipments were assessed a 50¢/ton fee for 1985 and a 60¢/ton fee for 2000. Finally deep-water colliers were allowed to run from Houston to the Atlantic Coast, and were assumed to be half as costly as coastal colliers on a ton-mile basis. All deep-water shipments were assessed twice the normal transshipment handling charge at the destination in an attempt to reflect the fact that there are few ports capable of receiving these colliers and this would tend to increase the cost of final distribution. The resulting transportation cost estimates for utility coal users are present in Appendix B, Tables 1 and 2.

B. Industrial Coal Transport

The use of coal in small retail lots for space heating has declined in the past 25 years (see Figure 4) and industrial coal use (exclusive of coking) has been concentrating in a few heavy industrial categories, such as Stone, Glass, and Clay products. This trend is expected to continue; however, while each such user has substantial coal requirements for process energy, etc., they are very clearly not large enough to apply the leverage that utilities have in negotiating for transportation. Industrial plants of this type tend to locate on rivers and waterways and take advantage of barge shipments where possible, but fuel costs constitute a much smaller portion of their total operating costs than do those of electric utilities. For this reason, the assumption was made that the cost of all industrial shipments would be comparable to spot-rail rates. The resulting transportation costs are presented in Appendix B, Tables 3 and 4 for 1985 and 2000, respectively.

C. Slurry Pipelines and the Railroad Industry

Considerable interest has arisen among utilities in using slurry pipelines for transporting their coal requirements. The economics of slurry pipelines are tied to the annual volume throughput, to the topography of each proposed pipeline route, to the availability of adequate water supplies and to a host of environmental and political uncertainties. Accordingly, while a discussion of the economics and postulated operating characteristics of a slurry line is presented here, slurry pipelines were not introduced into the model. Our coal slurry pipeline analysis was adopted from Bechtel data[12] and from a more recent study by the University of Illinois Center for Advanced Computation (CAC).[13]

Two commercial slurry pipelines have been built in the United States, one of which is currently operating. The first of these, a 10" diameter line, was constructed in Ohio by the Consolidation Coal Company in 1957. This 108 mile pipeline supplied 1.2 million tons of coal annually to the Eastlake Power Station of the Cleveland Illuminating Company until 1963, when increasing cost competition from the railroads caused the line to be put on a "stand-by" basis.

The other line, the 273-mile Black Mesa coal pipeline, currently supplies roughly five million tons of coal annually to the Mohave Power Station near Bullhead City, Nevada. This 18" line is owned and operated by a subsidiary of the Southern Pacific Transportation Company, the nation's second largest railroad. The Black Mesa coal mine in Arizona is located more than 100 miles from the nearest rail lines, and had connecting track been built, the rail distance would have been roughly 400 miles, 54% greater than the slurry distance.

Operating experience from these two lines has demonstrated that coal pipelines can be a feasible alternative to rail shipments, and has set the stage for an ongoing battle between the railroads and the slurry pipeline industry over the issue of eminent domain for slurry lines.

In 1962, a bill was introduced in Congress to grant slurry lines nationwide the right of eminent domain. The bill has yet to be passed, and is an ongoing issue in Congress. The railroads, fearful over the enormous potential loss of coal revenues to the slurry lines, have denied slurry companies the right to cross their rights-of-way, which for all intents and purposes eliminates the possibility of building any new lengthy pipelines. A key issue in the eminent domain dispute, yet to be determined at the Federal level, is whether coal slurries serve a legitimate public interest or are a purely private enterprise.

The current dispute centers around a proposed 1040-mile line stretching from Gillette, Wyoming to a consortium of utilities in Arkansas. Energy Transportation Systems, Inc. (ETSI), the line's sponsor, has attempted to circumvent the Federal stalemate by obtaining eminent domain rights from the individual states through which their line would pass. The Kansas legislature recently denied ETSI's request, and ETSI is currently exploring alternative routes which would circumvent Kansas.

One key question which has yet to be answered is the extent to which the granting of eminent domain to coal slurries might affect the financial solvency of western railways. The decline of rail systems in the Northeast stands as a reminder of how costly maintaining an insolvent rail system can be; the Federal response signals a commitment to maintaining a viable railroad system nationwide. One of the primary factors in this decline was the loss of many "bread-and-butter" railroad commodities, including coal, either to competing modes or to less rail-intensive commodity mixes. Clearly, if allowing coal to be slurried ultimately leads to an increase in the aggregate cost of shipping all commodities, the coal slurry concept makes little sense from a public policy standpoint.

The other side of this issue, however, is that as late as 1970, total coal production west of the Mississippi River amounted to slightly less than 44 million tons.[14] If all of this production were shipped 1000 miles at 8 mills/ton-mile, railroad revenues would total roughly $350 million, or roughly 20% of Union Pacific's 1975 operating revenues.[15] While this tells only part of the story, it suggests that the Western railways may be looking at coal more as a growth market than as a survival issue. An analysis of this subject is beyond the scope of the present study.*

Another important issue in this regard is whether existing rail capacity will be adequate to handle the increased transportation demand that expanding coal production will place on it. If new rail capacity or rail upgrading is required, how will this affect the overall cost of shipping coal and other rail-haul commodities? A recent study by Manalytics, Inc. for the Electric Power Research Institute sheds some light on this extremely complex issue.[16] Using the Federal Railroad Administration railroad network model, Manalytics simulated the behavior of the rail network in transporting all commodities in 1985 under two accelerated coal production scenarios. They focused their attention on sixteen key barriers between regions, corresponding to mountains, rivers, and other natural obstructions to easy capacity expansion. While their results must be examined with extreme caution, their conclusions are very suggestive:

> "The combination of these traffic demands on railroad capacity would overload many of the network

---

* A thorough discussion of the institutional constraints on slurry development is contained in Alex Sargent's, "Western Coal Transport: Unit Trains or Slurry Pipelines." U.S. Department of Transportation, DOT-OS-30104, August 1976.

links on the shortest path from origin to destination. Of the sixteen...barriers defined, eleven barriers have one or more overloaded link.... Traffic would have to deviate up to hundreds of miles to use alternative routes unless major changes in rail lines or rail operations are undertaken.... Expansion of traffic on island waterways is severely limited by congestion at certain key locations on the waterways network... The facilities for producing the (rail) equipment needed are readily available.... Clearly, aside from the financial aspects, the industry can obtain the equipment necessary to meet the expanded traffic demands. The constraints imposed by bottlenecks on the rail and waterway links are of much greater concern."(17)

A principal objective of the Manalytics study was to determine the level of coal traffic at which the existing rail network would begin to overload, and their scenarios were designed, in part, to create overloads at the barriers which they identified. Both of their scenarios for 1985 generated somewhat larger volumes of coal traffic than did either of our 2000 scenarios (these will be discussed in some detail later in this report). It speaks well for the fundamental strength of our railroad industry that serious bottlenecks for the existing network could only be identified by increasing non-coal traffic by 30% and also increasing coal traffic an average of five-fold over selected origin/destination links.

Additionally, since utilities typically negotiate coal supply contracts during the early stages of planning new capacity, the railroads should have adequate opportunity and a reasonably sound guarantee of revenues with which to plan and finance any needed track upgradings or additions.

It is very easy to fall into the trap of over-generalizing when reflecting on a complicated problem from afar. Nevertheless, based on the evidence available the railroads appear to have the physical resources to absorb the increase in freight traffic implied by the coal supply projections. The railroad industry makes a compelling argument in maintaining that many of its current difficulties stem predominently from underutilization of its facilities.

Legitimate public and private interest stand on both sides of the slurry pipeline dispute. There is every reason to believe that as the utilization factor of railroads' trackage increases their capital charges should decrease. Conversely, increasing traffic would force the railroads to replace their existing trackage much more rapidly than otherwise; the impact of financing this upgrading at today's higher interest rates and inflated dollars is likely to put upward pressure on rail tariffs. No acceptable method has been found to equitably assign maintenance charges to different types of trains passing over a section of track. Unit trains require the heaviest, most powerful locomotives and a loaded coal hopper is certainly more punishing to the track than a boxcar filled with tissue paper. If a railroad were to install extra heavy track to accommodate unit train shipments and rates rose to cover these costs, then the other commodities would in effect be subsidizing coal transportation. Finally, as track congestion increases and shipments begin experiencing delays, the effective utilization of the rolling stock will decline and inventory charges assinged to goods in transit will rise, further increasing costs.

To sum up, then, the impact of increasing coal traffic on any given rail link is extremely difficult to assess in terms of formulating public policy. Benefits of increasing the level of track utilization, if any, must be weighed against the costs of increasing track maintenance expenses and the costs resulting from increasing delays in transit for all other commodities. Obviously, sufficient data do not exist to attempt to quantitatively solve this problem.

If the premise is accepted that the rail network is currently underutilized and that maintaining a healthy, self-sufficient railroad industry is in the national interest, then a policy to encourage rail shipment, perhaps even to the extent of denying market entry to competitive modes may be justified. The Federal government's takeover of the bankrupt northeastern lines and the formation of Conrail signal a firm commitment to preserving our rail system.

The slurry pipeline question, seen in this light, boils down to the question of whether slurries pose a threat to the railroads' continuing ability to serve the national interest. If they do not, then the question arises of whether they represent a gain or a loss in social well-being. If they are found to offer an improvement, then it should be incumbent on Congress to grant eminent domain rights without further ado. The converse, of course, also applies.

This study does not pretend to address the political and institutional issues involved in evaluating the merits of slurry pipelines; rather, we will focus on the narrow economic issues that the current literature permits and offer a perspective based on the analysis we have performed.

The engineering economics of coal slurry pipelines are dominated by immense economies of scale. Bechtel has estimated coal transport costs of roughly 10.2, 6.8, and 4.8 mills per ton-mile for a 1000 mile pipeline of 5, 10, and 20 million ton per year (MMTPY) annual throughput, respectively in 1974.[18] By comparison, their corresponding estimate for a unit train shipment of this length is approximately 8.1 mills/ton-mile. Both capital and operating cost considerations contribute to these economies. The right-of-way required for the larger sizes are substantially the same as for smaller lines; a 25 MMTPY, 3.5 miles-per hour line will be 38" in diameter.

Also, the relative amount of steel pipe and construction labor required per annual ton of throughput decreases with increasing pipe size. Operating costs of the larger lines should decline due to decreasing friction losses of the viscous slurry to the pipe walls and to economies of scale in purchasing larger sized equipment which may emerge as more lines are built.

It should be noted that a 25 MMTPY line will require several enormous strip mines to supply its coal requirements, 6.4 billion gallons of water annually (a volume of one square mile by 31 feet deep) and will supply the coal energy required to fire 7,500 MW of base loaded coal-fired capacity. This generation would supply the nation's entire electrical requirements for roughly eight days at 1976 generation levels. It is an enormous project.

The following discussion will focus on a University of Illinois (CAC) analysis[19] of the 1040-mile, 25 MMTPY ETSI pipeline proposed to run between Gillette, Wyoming, and White Bluff, Arkansas. It should be noted that CAC has been an extremely vocal critic of the coal slurry concept, so that their analysis, given the very limited data available, might be considered a conservative estimate.

The pipeline system has four major components: (1) crushing/slurry preparation plants in Wyoming; (2) receiving/dewatering terminal(s) in Arkansas; (3) the pipeline itself; and (4) periodic pumping stations located at approximately 100-mile intervals along the route.

The slurry has been described as a "black toothpaste," and under ETSI specifications would contain roughly 48 volume percent of finely ground coal in an aqueous slurry. The design velocity of this line is 3.5 mph which corresponds to a 12.5 day transit time for the coal. Under emergency conditions it is possible to vary the throughput by altering the coal/water ratio or the slurry velocity or both. CAC has estimated that throughput can be reduced to 65% of design (16.25 MMTPY) by reducing the coal content to 38% and reducing line speed to 3 mph. Below 3 mph there is some danger of the coal settling in the line, leading to a "plug" which would force an emergency shutdown and purging the slurry into holding ponds located at each pumping station. There appears to be no technical reason why the coal content could not be reduced below 38%. Clearly, to do so would increase the dewatering costs at the line's terminus. Increasing the velocity of the slurry would allow throughput to be raised somewhat; however, this incurs a penalty of increasing pumping costs and increases the maximum hydraulic pressures experienced in the line. The economics of slurry pipelines strongly favor sizing components to the design capacity and operating as near to that capacity as feasible on a continuous basis.

Once a line such as this is in operation, any unexpected deviation has the potential for disaster. The pipeline would contain about 1.7 million tons of slurry during normal operations, of which 800,000 tons is finely ground coal. A blockage or break in the pipeline or the failure of one or more of the pumping stations may require that the slurry be purged into emergency holding tanks at each of the pumping stations, while flushing as much of the pipe as possible with water to prevent coal deposition within the line. Since complete flushing of the line may take 12.5 days, this represents a very substantial interruption of supply, even before time for the actual repairs is added. Slurry purged into stationary holding tanks will begin settling immediately and no generally accepted method has been demonstrated for satisfactorily reintroducing this to the pipeline. Furthermore, disposal of the flushing water, which will contain varying concentrations of fine coal particles, may pose a substantial environmental problem.

What is most uncertain, however, is the reliability with which a pipeline of this magnitude will operate. Pipeline sponsors and supporters exude optimism, maintaining that experience gained from the Consolidation and Black Mesa pipelines has taught them the important lessons about coal slurry technology, and that slurries have the potential for saving energy consumers billions of dollars. Detractors maintain that problems of scaling the technology up too quickly, coupled with unforeseen environmental problems resulting from entering colder climates, will turn the slurry pipeline concept into an economic and environmental nightmare.

There seem to be no neutral actors in the slurry pipeline battle being fought before Congress. Existing capital cost data on slurry pipelines have been prepared from Bechtel/ETSI data. These are the chief sponsors of coal slurries. Detractors (including CAC) have charged that these estimates are misleading, and that the most serious impacts and risks of the technology have been concealed rather than exposed by their analysis; in short, if the whole story were presented in an unbiased fashion, the relative economics of the competing modes would look entirely different than those suggested by the presently available information.

In the CAC study, an attempt was made to independently estimate the capital and operating costs of the 25 MMTPY ETSI pipeline from available information on the Black Mesa pipeline. They prefaced this work with this caveat;

> "When a private line is built it is often impossible to say how much of the capital cost (if any) has been absorbed by the companies at either end and not

debited to the pipeline. Similarly, shipment costs become akin to transfer prices."[20]

Using a linear extrapolation of capital cost figures from the Black Mesa pipeline CAC estimated the 1975 capital cost of the Wyoming-Arkansas line to be $1.034 billion. They estimated major O&M expenses at $19.2 million annually, and, adopting their annual labor requirements at our estimated average labor cost per manyear of $34,400, we estimated annual labor expenses of $7.3 million. Estimating a cost of capital for ETSI of 16% yields an annual revenue requirement of $192 million, which corresponds to a charge of $7.67/ton of coal delivered, or 7.4 mills/ton-mile. CAC used a lower fixed charge rate (13.27%) so their cost estimate for this line (which they didn't calculate) would be somewhat lower, roughly $6.55/ton and 6.3 mills/ton-mile.

Middle South Utilities has reported the estimated delivery cost through the ETSI line to be $7.90/ton, corresponding to 7.6 mills/ton-mile.[21] Whether this number refers to 1974 $ or 1975 $ and its basis are unclear, so it is included as a reference rather than as an absolute benchmark.

A summary of the available slurry pipeline estimates is presented in Figure 9. Bechtel data were escalated 5% from their 1974 estimates to obtain 1975 charges. The Middle South Utilities estimate, although reported in late 1976 was not scaled due to its uncertain basis.

It is most important to recognize that the numbers presented from different sources are not comparable on an absolute basis, but they provide a basis for examining the likely range. Bechtel acknowledges [22] that a number of items are ignored in their estimates. Nevertheless, it appears that their estimates are roughly 40% below those of other sources. It is conceivable that they are imputing a substantial benefit to the slurry pipeline

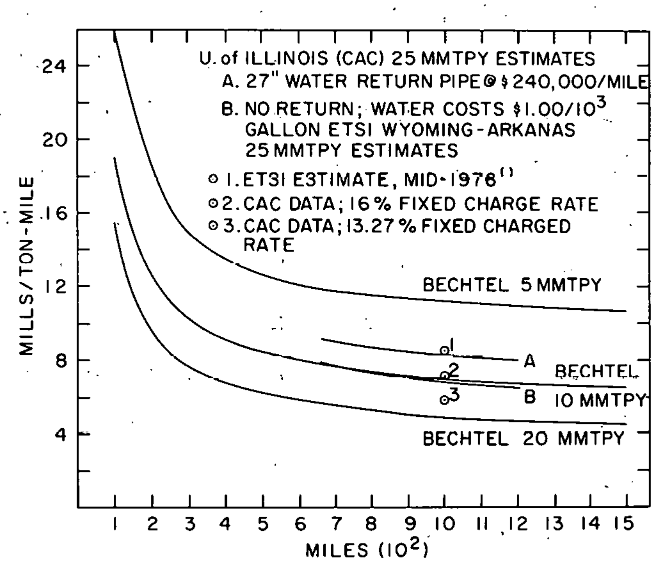

Figure 9. Comparative cost estimates for coal slurry pipelines (1975 in 1975 $).

through capitalizing (thereby "locking in") most of their future shipping costs, thus insulating them from future escalation and inflation of other modes. This was not mentioned in the report.

D. EHV Transmission of Coal Derived Energy

A final alternative available to utilities is to generate power at the minemouth and transmit the electricity to distant demand centers via extra high voltage transmission (EHV) lines. Perhaps the most widely-known proposal of this type was the recently abandoned Kaiparowits project, sponsored jointly by the Southern California Edison Co., the San Diego Electric and Gas Co., and the Arizona Public Service Co. This project would have involved the coordinated development of four mines in southwestern Utah, producing 12 million tons of coal annually feeding a central 3000 MW power plant and a 500 KV transmission system to deliver the power to the companies' respective service areas.

EHV transmission, as the analysis in this section will demonstrate, is normally quite a bit more expensive than other modes for long distance shipment of coal or coal derived energy. Transmission may be justified in instances where other modes are unavailable or in situations where economic and/or environmental constraints prohibit locating the power plant closer to the demand center.

Most long-distance EHV links in this country have been built either to improve transmission system stability or to transmit power between systems having different seasonal peaking characteristics. It should be emphasized that the transmission lines being discussed in this section are intended for interregional, one-way transmission of electricity from a minemouth power plant to a distant service area. An entirely different type of analysis would be required to investigate the economics of building a centrally located power plant with transmission facilities serving a number of dispersed load centers.

Two types of lines were examined for this study--76 KV AC and 600 KV DC. The basic facilities costs for these systems were adopted from the University of Illinois study,[23] which were found to be in rough agreement with data presented in the 1970 National Power Survey.[24] We disagreed with several of their operating assumptions, so these were modified in accordance with our own estimated.* Both lines were assumed to transmit 3000 MW at capacity, which is in line with current design estimates of maximum practical transmission loadings.

The costs of these systems include capitalizing the sending and receiving substations and transmission lines, operation, maintenance and materials required to operate the facilities, and the costs of lost plant capacity and energy due to the impedence of the systems. These costs are compared to those for "equivalent" unit train operations in Figure 10. It should again be emphasized that these costs are crude estimates and should be viewed in a relative, rather than an absolute sense.

The data show a clear cost advantage for long-distance dc transmission (over ac). AC is more economical at distances below 500 miles due to the much lower costs of AC sending and receiving substations. For longer distances, however, the lower line losses of the DC line more than compensate for the higher DC substation costs and the dc advantage broadens as the transmission distance increases.

---

* Most notably, as follows: CAC estimated the line would operate at 90% capacity factor, with coal-burning capacity valued at $180/kW. We felt that 70% and $460/kW were more in line with current experience. We also felt a 15.5% fixed charge rate was more appropriate than CAC's 13.27%.

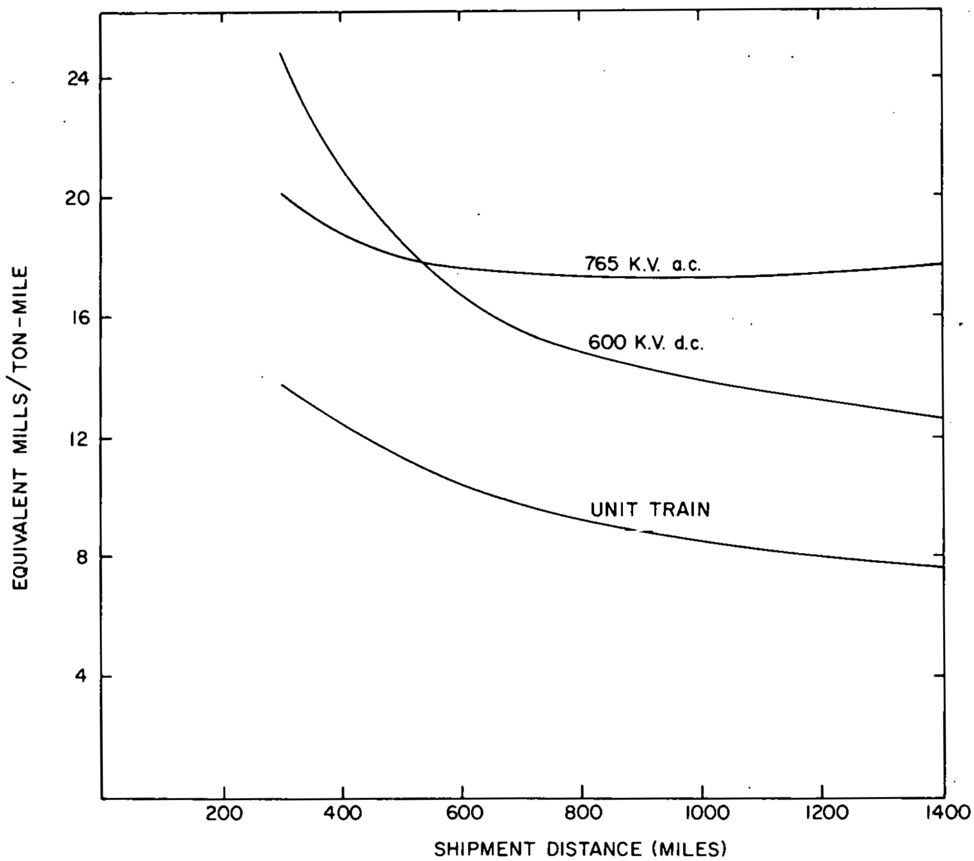

Figure 10. Comparative cost for unit train and EHV transmission (subbituminous coal, 1975 $).

E. Transportation of Oil and Gas

The oil and natural gas industries operate in modes completely different from those of the coal industry (and quite differently from each other). The market for synfuels is contingent on the continuing decline in domestic oil and gas production coupled with economic and/or political disincentives to importing these fuels. Many of these factors are only coincidentally related to energy market pressures; accordingly, the growth rate of a synfuels industry is a highly speculative matter.

Making assumptions concerning the size of the national market for these fuels, market forces relating to the cost of coal and the pipeline cost of transporting these fuels to consumers can give some indication of where these industries are most likely to develop. Since synfuel plants will be likely to locate at the mine-mouth (due to the higher cost of shipping coal than of piping the products to distant markets) the western coals are clearly the preferred feedstock for minimizing the produced cost of energy.

However, the western states are currently producing more oil and gas than they are consuming and once Alaskan supplies begin flowing there will likely be a substantial energy glut west of the Mississippi River. The markets for synthetic oil and gas (assuming they exist) will likely be in the northeastern states, and there currently exists almost no pipeline capacity between the Rocky Mountains and this region. New and increasingly expensive pipelines will have to be constructed as a Rocky Mountain synfuels industry expands.

Conversely, the eastern and midwestern coal fields lie squarely on the existing pipeline arteries which will be increasingly underutilized as Gulf Coast production dwindles (Figure 3). Similarly, since most western production meets current utility NSPS for sulfur, synfuel producers will be competing with an equally capital-intensive electric utility industry willing to pay a premium for this coal. Appalachian and Midwestern high sulfur coal is facing competition from low sulfur supplies and will probably supply a dwindling share of its current market. Gaseous effluents of sulfur in synfuel reactors occur predominently as H_2S, for which well developed removal technologies exist. Synfuels manufacturers, then, should have little incentive to seek low-sulfur feedstocks, because acid-gas removal systems are integral to the processes, and will be installed regardless of the feedstock sulfur content.

The question which must be addressed is whether the combination of higher transportation costs, environmental considerations and competition for low-sulfur coal will be strong enough to drive the synfuels industry from the Western region.

Transportation costs for high-Btu Gas and syncrude were formulated in two parts; the cost of using existing pipeline networks where available, and the cost of using new construction to ship synfuels products. Eastern coals were assumed to use only the pipeline routes passing through their location and western regions (except the Southwest, which could use the western artery to supply the Pacific region) require new pipeline construction. Where combination of new and existing capacity could be used, the joint cost was estimated.

Bechtel data were used to estimate the costs of transporting these fuels.[25] A review of natural gas and crude pipeline maps suggested that the networks consisted, on the average, of 30" and 18" pipelines, respectively. Pipeline capacity estimates[26] indicated that the synfuels industry would attempt to take advantage of economies of scale to pump the products of several plants in a common line. Accordingly, the initial model runs were made assuming transportation costs corresponding to the network average; where a synfuels flow was insufficient to support this size pipeline the smaller pipeline was used.

Both capital and operation/maintenance costs were assumed to escalate at 2.5% annually. Once a pipeline was in place, however, its capital charge was held constant and only O&M costs escalated. A summary of the transportation charges which might be incurred in shipping oil and high-Btu gas are presented in Table 5, along with comparable costs of shipping WNGP subbituminous coal and electricity.

Tables B-5 and B-6 in Appendix B present the synfuels transportation charges adopted for synthetic high-Btu gas and liquids. These were estimated by adapting pipeline size to the capacity of synfuels ultimately shipped, as described above.

Low-Btu gasification was assumed to substitute for oil and gas as process energy for heavy manufacturing applications. These industries are concentrated along the Ohio River so only Appalachian and Midwestern high sulfur coal were permitted for this purpose, and transportation charges were assumed to be negligible, since the Ohio River System bisects these three supply regions.

TABLE 5

Comparative Costs of Transporting 10^6 Btu 1000 Miles

(1975 $)

	1975	1985	2000
GAS PIPELINE			
30" Pipeline			
Constructed Prior to 1975	.34	.36	.39
On-Line in 1985		.45	.48
On-Line 2000			.65
18" Pipeline			
On-Line in 1985		.59	.61
On-Line in 2000			.84
OIL PIPELINE			
18" Pipeline			
Constructed Prior to 1975	.08	.08	.09
On-Line in 1985		.11	.11
On-Line in 2000			.15
9" Pipeline			
On-Line in 1985		.19	.19
On-Line in 2000			.27
EHV ELECTRICAL TRANSMISSION			
765KV ac	2.70		
600KV dc	2.15		
WEST & NORTH GREAT PLAINS COAL			
Spot Rail	.58	.74	1.07
Unit Rail	.49	.63	.91
Coal Slurry Pipe(On-Line 1985)			
$5x10^6$ Ton Per Year		.67	.76
$10x10^6$ TPY		.44	.50
$20x10^6$ TPY		.31	.36
River Barge	.22	.28	.41
Coastal Collier	.11	.14	.20

V. DETERMINATION OF COAL ALLOCATIONS

The final step in estimating the cost of each region's energy options is to sum the extraction, transportation, and any unusual environmental control costs. This section presents the allocations resulting from this analysis for each consuming sector.

A. Utility Coal Combustion

Tables B-7 and B-8 in Appendix B present the costs of delivering coal energy to utilities in the nine census regions for 1985 and 2000. The costs were derived by adding the coal prices in Tables 1 and 2 to the transportation costs in Tables B-1 and B-2. A scrubbing surcharge of 50¢/million But in 1985 and 62¢/million Btu in 2000 was added to utility consumption of high sulfur coal, as discussed in Chapter II.B.

B. Industrial Coal Consumption

Tables B-9 and B-10 in Appendix B present regional coal cost estimates for industrial users in 1985 and 2000, respectively. These costs are sums of the coal costs in Tables 1 and 2 plus the industrial transportation costs presented in Tables B-3 and B-4. No penalties were assessed for environmental control.

C. Gas Supplies

It was assumed that the wellhead price of natural gas will be deregulated for all markets. Wellhead prices for 1985 and 2000 were assumed to be $1.93 and $2.19 per million Btu, respectively.[27] The shipping costs developed in Table B-5 were added to arrive at the delivered cost to the different regions.

Substitute natural gas prices were derived by using process costs (capital plus operation/maintenance) of $2.95 per million

Btu of gas. Feed coal costs were calculated by multiplying the coal prices in Tables 1 and 2 by a factor of 1.61, corresponding to a plant conversion efficiency of 62%, and the delivered cost of SNG was computed by adding the appropriate transportation charges.

Low-Btu gas costs were developed by adding a processing cost of $2.13 per million Btu to the raw coal cost multiplied by a factor of 1.33 (the factor corresponds to a plant conversion efficiency of 75%).

Alaskan gas supplies of 1.00 quad were assumed for 1985 and 2000. The delivered cost of this gas was estimated to be $3.22 and $3.79 to the East North Central and $3.49 and $4.12 to the Pacific Coast for 1985 and 2000, respectively.

Atlantic Outer Continental Shelf (OCS) Gas Supplies of 0.7 Quads were assumed for 2000 only. These were assumed deliverable to the Atlantic Coast at a cost of $2.25 per million Btu.

The resulting costs are presented in Tables B-11 and B-12.

D. Oil Supplies

World oil prices of $2.24 and $2.87 per million Btu were assumed for 1985 and 2000.[28] Shipping costs of 7 and 10¢ per million Btu were added to these costs for delivery to Atlantic and Pacific ports. The transportation costs indicated in Table B-6 were added to these costs.

Synthetic crude costs were estimated in a manner similar to that used for SNG. Processing costs were assumed to be $2.83 per million Btu of product; conversion efficiency was assumed to be 67%, so feed coal prices were multiplied by a factor of 1.49. Finally, the appropriate transportation charges from Table B-6 were added to arrive at the delivered prices.

Alaskan oil supplies of 4.3 quads were delivered to the Pacific Coast for both periods, and pipeline charges were added to move them eastward. Atlantic OCS oil supplies of 0.59 quads were assumed for the year 2000 only. The resulting cost options are presented in Appendix B, Tables B-13 and B-14.

E. Distribution Scenarios

Three scenarios for coal distribution and consumption were generated: one scenario including 1.1 quads of synfuel production in 1985, and two cases for 2000; one with 4.5 quads of synfuels production and an accelerated case with 9 quads. It is important to note that these supplies were "forced" into the solution, and that some of the plants would not be built without this intervention. This is particularly true of the coal-derived liquids, where none could compete with the assumed world oil price in 1985 or 2000.

The 1985 scenario incorporated the production of the following synfuels:

	10^{12} Btu Produced	Approximate No. of Plants
Low Btu Gas	500	6
High Btu Gas	500	6
Syncrude	100	1

Low Btu gas production, as discussed in Section IV, was limited to the Appalachian regions and the Midwest. Since only a single syncrude plant would be on line by 1985, it was decided to arbitrarily place this plant in the Midwest, since it will be, in large part, a research facility. The location of substitute gas production and all coal shipments were constrained only by the availability of adequate coal supplies.

The distribution of coal for this run is presented in Tables 6 and 7 for direct combustion and coal conversion, respectively.

TABLE 6

1985 Distribution of Coal for Direct Consumption

(10^{12} Btu)

			Demand Region								
Coal Supply Region	Sulfur Content	Application	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	Low	Utility	88	286							
		Industrial									
	High	Utility		2057							
		Industrial	34	602							
South Appalachia	Low	Utility			2515	189	1186				
		Industrial									
	High	Utility				105					
		Industrial			512		343				
Midwest	Low	Utility				312					
		Industrial									
	High	Utility				1676					
		Industrial				1218		276			
Gulf	High	Utility			169						
		Industrial							284		
East North Great Plains	Low	Utility					353				
		Industrial									
	High	Utility									
		Industrial									
West North Great Plains	Low	Utility				1576		1631	635	629	
		Industrial									
	High	Utility									
		Industrial								97	90
Rocky Mountain	Low	Utility								116	212
		Industrial									
Southwest	Low	Utility							137		
		Industrial									
	High	Utility									
		Industrial									90

TABLE 7

1985 Consumption of Coal for Synfuels Production
(Synfuels Produced in 10^{12} Btu)

Region of Synfuel Production	Coal Feed Sulfur Content	Type of Synfuel Produced	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
			Synfuel Consumption Region								
North Appalachia	High	Low Btu Gas		500 (6)							
		High Btu Gas	170(2)								
		Liquids									
South Appalachia	High	Low Btu Gas									
		High Btu Gas									
		Liquids									
Midwest	High	Low Btu Gas									
		High Btu Gas									
		Liquids				100 (1)					
Gulf	High	High Btu Gas									
		Liquids									
East North Great Plains	Low	High Btu Gas									
		Liquids									
	High	High Btu Gas						53 (1)			
		Liquids									
West North Great Plains	Low	High Btu Gas								190(2)	
		Liquids									
	High	High Btu Gas									
		Liquids									
Rocky Mountain	Low	High Btu Gas									
		Liquids									
Southwest	Low	High Btu Gas									
		Liquids									
	High	High Btu Gas									87 (1)
		Liquids									

For the 2-year 2000 runs, all synfuels plants were allowed to locate in any region, except for Low-Btu gas plants, as above. Plants generated by the 1985 run were "forced" to remain. Synfuels production for the two cases were assumed to be as follows:

	4.5 Quad "Most Likely" Case		9 Quad "Accelerated" Case	
	10^{12} Btu	Plants	10^{12} Btu	Plants
High-Btu Gas	2000	25	4000	50
Low-Btu Gas	1500	19	3000	38
Syncrude	1000	10	2000	20

The demand by industrial and utility coal consumers was held constant for the two cases; the additional synfuels produced in the accelerated case reduced the importation of LNG and foreign oil. This higher level of synfuels required 15% more coal than nominal supplies. Each regional supply was escalated by this factor to accommodate the increased demand. This increases the national coal production in 2000 to slightly more than 2.1 billion tons, which is well within the realm of possibility, representing a 4.9% annual growth rate between 1975-2000.

The model distributions generated by these two runs are presented in Tables 8 through 11.

Table 8

2000 Direct Coal Consumption - 4.5 Quad Synfuel Production

(10^{12} Btu)

Coal Supply Region	Sulfur Content	Application	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
			Demand Region								
North Appalachia	Low	Utility		507							
		Industrial									
	High	Utility		2110							
		Industrial	52	877							
South Appalachia	Low	Utility	128	992	3207		1751				
		Industrial									
	High	Utility									
		Industrial			895		588	477	97		
Midwest	Low	Utility									
		Industrial									
	High	Utility									
		Industrial				1840					
Gulf	High	Utility									
		Industrial							757		
East North Great Plains	Low	Utility									
		Industrial									
	High	Utility									
		Industrial									
West North Great Plains	Low	Utility				4200		2432	1196	965	475
		Industrial									
	High	Utility									
		Industrial								210	
Rocky Mountain	Low	Utility									125
		Industrial									240
Southwest	Low	Utility									
		Industrial									
	High	Utility									
		Industrial									

TABLE 9

2000 Coal Consumption for Synfuels - 4.5 Quads Produced
10^{12} Btu Synfuels (# of Plants)

Region of Synfuel Production	Coal Feed Sulfur Content	Type of Synfuel Produced	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	High	Low Btu Gas		500(6)		693(8)					
		High Btu Gas		170(2)							
		Liquids									
South Appalachia	High	Low Btu Gas									
		High Btu Gas									
		Liquids									
Midwest	High	Low Btu Gas				307(4)					
		High Btu Gas				1137(14)					
		Liquids				100(1)					
Gulf	High	High Btu Gas									
		Liquids									
East North Great Plains	Low	High Btu Gas						153(2)			
		Liquids									
	High	High Btu Gas						82(1)			
		Liquids									
West North Great Plains	Low	High Btu Gas								338(4)	
		Liquids								600(6)	
	High	High Btu Gas						32(1)			
		Liquids									
Rocky Mountain	Low	High Btu Gas									
		Liquids									
Southwest	Low	High Btu Gas									
		Liquids									
	High	High Btu Gas									87 (1)
		Liquids								300(3)	

TABLE 10

2000 Direct Coal Combustion - 9 Quad Synfuels Production

(10^{12} Btu)

Coal Supply Region	Sulfur Content	Application	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
			Demand Region								
North Appalachia	Low	Utility		608							
		Industrial									
	High	Utility		2088							
		Industrial	52	877							
South Appalachia	Low	Utility	128	913	3119	637	1751				
		Industrial									
	High	Utility									
		Industrial			895		588	477			
Midwest	Low	Utility									
		Industrial									
	High	Utility									
		Industrial				1840					
Gulf	High	Utility			88						
		Industrial							854		
East North Great Plains	Low	Utility									
		Industrial									
	High	Utility									
		Industrial									
West North Great Plains	Low	Utility				3563		2432	880	965	402
		Industrial									
	High	Utility									
		Industrial								210	
Rocky Mountain	Low	Utility									198
		Industrial									240
Southwest	Low	Utility							316		
		Industrial									
	High	Utility									
		Industrial									

TABLE 11

2000 - Synfuels Production - 9 Quad Total Production
Synfuels in 10^{12} Btu (# of Plants Required)

Region of Synfuel Production	Coal Feed Sulfur Content	Type of Synfuel Produced	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	High	Low Btu Gas		880 (10)		1063 (13)					
		High Btu Gas		170 (2)							
		Liquids									
South Appalachia	High	Low Btu Gas			326 (4)						
		High Btu Gas									
		Liquids									
Midwest	High	Low Btu Gas				831(9)					
		High Btu Gas				1662(20)					
		Liquids				100(1)					
Gulf	High	High Btu Gas									
		Liquids									
East North Great Plains	Low	High Btu Gas						341 (4)			
		Liquids			73 (1)						
	High	High Btu Gas						82 (1)			
		Liquids				18(0)					
West North Great Plains	Low	High Btu Gas								1313 (16)	
		Liquids				825(8)				836 (9)	
	High	High Btu Gas									
		Liquids				69(1)					
Rocky Mountain	Low	High Btu Gas									
		Liquids									
Southwest	Low	High Btu Gas									66(1)
		Liquids									
	High	High Btu Gas									365(4)
		Liquids								75 (1)	

VI. POTENTIAL NATIONAL MARKET PENETRATION OF COAL-BASED SYNTHETICS

It is observed in the analysis to this point that the conversion of coal to synthetic liquids and gases is not viable in comparison to the assumed prices of competitive naturally-occurring oil and gas. However, the analysis is useful in a relative sense, since it provides the optimal regional allocations of resources in the face of possible changing supply curves for conventional fuels. It is also instructive to determine the economic boundaries where synthetic fuels become competitive.

This issue is addressed using the Brookhaven Energy System Optimization Model (BESOM). The model has been used extensively in addressing national policy and technological issues in support of various ERDA programs. Briefly, BESOM is a linear-programming optimization model which allocates resources (supplies) to meet exogenously specified demands in all consuming sectors. Technologies are defined for all operations involving specific fuels including their extraction, refinement, conversion, transport, distribution, and utilization. Considerable technological detail is also included in comsuning sectors, containing detailed end-use device costs and efficiencies.

The model encompasses the entire energy system and reflects the full feasible range of interfuel substitutability. It includes both electric and nonelectric energy forms and focuses on the technical, economic, and environmental characteristics of the energy conversion, delivery, and utilization devices that make up the energy system. The analytical approach, in its general form, considers n alternative supply categories, and a set of m demand categories, providing n x m possible supply-demand combinations or paths. The solutions obtained indicate the optimal supply-demand configuration of the energy system within the constraints on resources, demands, and environmental impacts that are specified exogenously. The model may be formulated on a regional or national level for some future planning year by specifying, along with the appropriate constraints, a cost coefficient, supply efficiency, utilization efficiency, and set of environmental impacts for each feasible supply-demand combination. The load-duration characteristics of electrical demands are also incorporated in the model. The optimization may be performed with respect to cost, or alternatively, with respect to an environmental effect or some arbitrary combination of such effects. Other objectives and policy issues may be incorporated in the model through constraint equations.

BESOM also provides economic insights regarding the values of various fuels in meeting demands. The model generates the marginal value of fuels which are fully utilized at the level to which they are constrained, thus indicating the value to the energy system of incremental (marginal) supplies of that fuel.

The model was used in the following mode. A group of potential coal-based supplies consisting of low and high Btu gas, coal liquids, methanol and hydrogen were assumed to be available to compete with conventional oil and gas in the year 2000. The price schedule for fuels used was:

Crude Oil:	$\$2.87/10^6$ Btu
Natural Gas:	$2.19/10^6$ Btu
Coal:	$0.65/10^6$ Btu

These are wellhead and minemouth fuel price. The coal price is the average minemouth price of all the coal used in the regional analyses. The optimization model adds transportation, refining and markup charges to the producer prices, resulting in a delivered cost to the consuming sector which is appropriate for that part of the market.

The synthetic coal-based fuel constraints in the year 2000 were assumed below:

Coal Liquids:	2.0×10^{15} Btu
High Btu Gas:	2.0×10^{15} Btu
Low Btu Gas:	3.0×10^{15} Btu
Hydrogen:	2.0×10^{15} Btu

The basic fuel prices assumed above were raised incrementally at constant rates to ascertain the competitive prices of oil and gas at which the synthetic fuels entered the solution. The results are shown in Figure 11. Thus, for example, coal liquids are the first synthetic fuel entering the market, at a production cost of $\$3.70/10^6$ Btu based on a coal cost of $\$0.79/10^6$ Btu. Then, in succession low Btu gas, hydrogen, and finally synthetic natural gas (SNG) enter the market, but the SNG is competitive only when natural gas is about $\$4.56/10^6$ Btu, and at a coal price of $\$1.28/10^6$ Btu ($27.50 per ton). It should be noted that capital and O&M charges for synthetic fuels were held constant in the analysis but the coal cost was raised at the same percentage rate as oil and gas. Table 12 summarizes the marginal values of the synthetic fuels in meeting demands; i.e., the potential savings to the energy system of an additional unit of supply from that source, if it becomes available. It is apparent that as conventional oil and gas prices rise, the synthetic fuels become of increasing value to the energy system, even as coal prices rise.

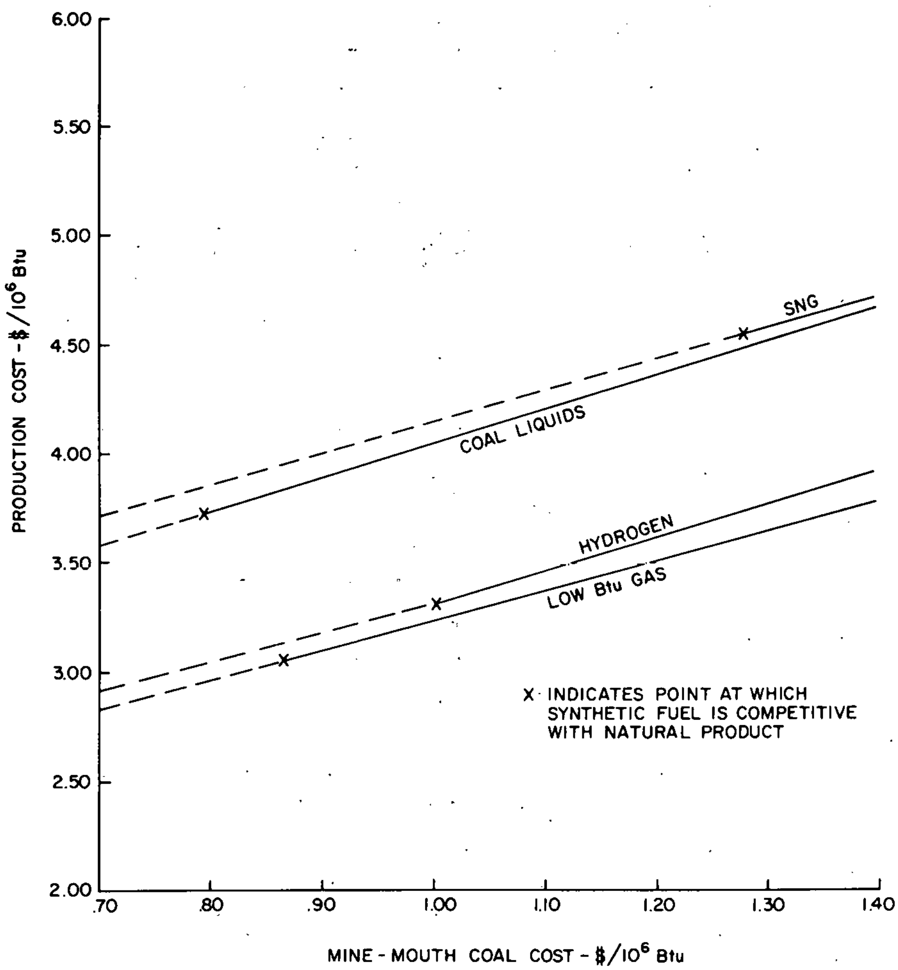

Figure 11. Synthetic fuel costs vs. coal cost.

TABLE 12

MARGINAL VALUES OF COAL SYNTHETICS
(All in $/10^6 Btu)

Crude Oil										
Cost	3.45	3.74	4.03	4.32	4.61	4.90	5.19	5.48	5.77	6.06
Natural Gas										
Cost	2.63	2.85	3.07	3.29	3.51	3.73	3.95	4.17	4.39	4.61
Coal										
Cost	0.79	0.86	0.93	1.00	1.07	1.14	1.21	1.28	1.35	1.42
Coal Liquids										
Cost	3.73	3.83	3.94	4.05	4.15	4.26	4.36	4.47	4.58	4.68
Marginal Value	0.07	0.28	0.49	0.71	0.92	1.13	1.34	1.55	1.77	1.98
SNG										
Cost								4.54	4.64	4.75
Marginal Value								0.00	0.00	0.00
Low Btu Gas										
Cost		3.05	3.14	3.23	3.33	3.42	3.51	3.61	3.70	3.79
Marginal Value		0.08	0.24	0.39	0.53	0.68	0.83	0.97	1.13	1.28
Hydrogen										
Cost				3.31	3.42	3.52	3.63	3.74	3.85	3.95
Marginal Value				0.11	0.24	0.37	0.51	0.60	0.60	0.60

Note: Where no entry exists, synthetic fuel was noncompetitive and not used.

VII. IMPLICATIONS AND CONCLUSIONS IN THIS STUDY

The preceding analysis has provided a data base and methodology from which the implications of coal's "rebirth" may be addressed. While regional distribution patterns have been developed within the confines of our supply, demand, and cost assumptions for 1985 and 2000, the limitations of the methodology preclude the consideration of these patterns as "forecasts" or "projections."

These limitations deserve reemphasis at this time to provide an adequate foundation for discussion which will follow. First, it was assumed that coal distribution in these years would take place in such a way as to minimize the total cost of coal energy to all users based on "today's" cost projections. This ignores the reality that much of the current coal distribution is based on the perceived costs of 5 to 30 or more years ago, and that coal users have substantial capital and contractual incentive to maintain these shipments for the lifetimes of these facilities.

Another limitation is that we have assumed that coal suppliers, shippers, and consumers will act as independent bargaining units limited by the energy options permitted by the model. An example of the shortcomings of this approach is that it ignores the incentives of integrating operations as American Electric Power is doing by preparing an integral unit train/barge network for shipping western coal to their Ohio River Valley service area.

By shipping coal from supply to demand centroids, the wide variation in costs introduced by the geographically dispersed nature of both has been ignored. This precludes, for example, the option of building minemouth generating plants for serving local electricity requirements, thus avoiding intermediate coal transportation charges entirely. The Rocky Mountain demand region, for example, encompasses 850 thousand square miles, the West North Great

Plains, Rocky Mountain, Southwest, and part of the East North Great Plains supply regions, but is represented in the model as a point demand at Salt Lake City. This introduces a bias away from local consumption of some of this coal and leads to an overestimation of the aggregate coal transportation charges which will actually be borne by coal users.

Within these constraints, however, the patterns from a reasonable basis for exploring the supply, transportation, and demand issues which will influence the expansion of coal use in the U.S. during the final quarter of this century. By regionalizing the supply and demand components, issues which will bear heavily on these regions may be examined more closely. This is especially important for the relatively undeveloped supply regions in the Rocky Mountains which will bear the brunt of the environmental impacts should current forecasts of expansion of their production be borne out. The linear programming format allows first-order estimates to be made of the impacts of such policies as an increase in regions' severence taxes and the institution of a national policy to scrub all coal-fired power plants.

This chapter will undertake to explore some of these issues by focusing on coal supply, transportation, and demand in turn, and, within each of these three areas, by examining those regions which have the greatest stake or which have the largest number of options.

The model formulation and the distribution patterns generated both suggest that the greatest number of options and the largest impacts will result in the electric utility sector of coal use. Substantial supply impacts may be expected in the western states from the expansion of utility coal use and from expansion of a synthetic fuels industry, both through a rapid increase in mining employment and through an expansion of consumptive water use for synthetic fuels production. This latter impact, will be minimal in 1985 but could become critical by 2000, particularly if an accelerated synfuels policy is pursued.

At the regional level of aggregation we have specified the non-utility industrial sector is seen to have the fewest options and will be minimally impacted by various coal policy options. This is true because of the model requirement of relatively expensive spot-rail coal transportation, for industry thus effectively reducing the geographic "radius" from which coal could be economically transported; it is also reasonably due to each industrial consumer's relatively low coal requirements and to the small fraction of total manufacturing costs attributable to energy costs. The steel industry, which was not modeled, has located within close proximity to their coking coal and iron ore reserves and many similarly be expected to be largely unaffected by national and/or regional coal policies.

A. Coal Supply

Tables B-7 and B-8 substantiate the economic interest shown by midwestern utilities in western coal. Eastern utilities are seen to demand almost six quads more coal energy than will be available from eastern low sulfur coal production in 1985 and 2000. Nowhere is this shortage more critical than in the East North Central region, where utility demand will outstrip midwestern low sulfur production by more than 10 to 1. The shortfall will have to be met by using some combination of high sulfur eastern coal with flue gas desulfurization and importing low sulfur western coal. The cost estimates in these Tables point out that importing coal from the West North Great Plains regions is more than 20¢ per million Btu cheaper than using high sulfur eastern coal with scrubbers.

At the same time, these costs point out the quandary that utility executives find themselves in. Current Federal environmental policy makes scrubbing mandatory in all new coal-fired power plants; a scrubbing surcharge will have to be added to their costs as well, which almost dictates the use of midwestern high sulfur coal with scrubbers.

North and Merkhofer estimated damage cost of 18 and 46¢ per pound of sulfur emitted by rural and urban power plants in 1975;[29] such great uncertainty attended their estimates, however, that confidence limits placed on these average estimates ranged from a low of 8¢ per pound for the rural plant to a high of $2.00 for the urban plant. Using these average estimates as the basis for an emissions tax, and with a choice of burning either 3.0 lbs sulfur/ million Btu midwestern coal or 0.65 lbs. sulfur/million Btu western coal with or without an 80% effective scrubber assumed to be available for 90% of the plant's normal operation, a utility might be confronted by supplementary environmental charges as shown in Table 13.

While the supplementary costs presented in Table 13 are hypothetical, they suggest that in most circumstances of accelerated environmental control utilities will still have a substantial incentive to use low sulfur coal, although that incentive will probably be lower than under New Source Performance Standards. It is worth noting that in most urban Air Quality Control Regions the only plant which could be built today is the low sulfur plant with FGD and that the scrubbed high-sulfur plant would have to shut down with each scrubber outage to meet the NSPS.

Two significant conclusions emerge from the preceding discussion. First, it is likely that a substantial market for western coal will exist in midwestern and eastern utility markets; its

TABLE 13

SUPPLEMENTARY ENVIRONMENTAL CHARGES

TO A HYPOTHETICAL UTILITY

(1985 in 1975 ¢/10^6Btu)

(1)	(2)	(3)	(4)	(6) (=2+4)	(7)	(8) (=2+7)
			URBAN PLANT		RURAL PLANT	
SULFUR CONTENT (lbs S/10^6Btu)	FGD CHARGE	AVERAGE EMISSIONS (lbs S/10^6Btu)	EMISSIONS TAX (@46 ¢/10^6Btu)	TOTAL CHARGE	EMISSIONS TAX (@18 ¢/10^6Btu)	TOTAL CHARGE
3.0	.50	0.84	39	89	15	65
0.65	50	0.18	8	58	3	53
0.65		0.655	30	30	12	12

rate of penetration will be a function of the combination of technological and/or emission tax fixes decided on by federal and state environmental agencies. Secondly, it is apparent that markets for high sulfur coal will become increasingly depressed by any further tightening of emission standards.

On the basis of our cost assumptions, the model allocated roughly 2.1 quads of western coal to utility markets east of the Mississippi River in 1985 and twice that amount in 2000. The bulk of this quantity is low sulfur subbituminous coal originating in Montana and Wyoming bound for utilities in the Chicago area, where this coal accounts for 41% of the coal-fired generation in 1985 and averaged 92% for the two 2000 cases. These allocations were felt to be unreasonably concentrated as a result of the linear programming formulation--a more realistic conclusion is that West North Great Plains coal would account for 29% of the coal-fired electric generation in the East Central region in 1985 and 65% in 2000. This amounts to 89 million tons in 1985 and 236 million tons in 2000. In 1975, East Central utility coal demands from the Northern Great Plains region totaled roughly 20 million tons,[30] so these levels do not seem unreasonable.

Total WNGP coal production in 1985 was estimated to be 274 million tons of which some 230 million tons will be distributed to regions outside the Rocky Mountains. Estimating mining productivity at 125 tons per man-day in this region leads to an estimate of 7600 additional mine personnel in this region by 1985, or a total population influx of some 38,000 people between 1975 and 1985, including families and the ancillary support required to maintain a number of new mining towns. Between 1985 and 2000 an additional 10,000 miners would be required, so that these production forecasts imply an influx of roughly 90,000 people into the southeastern Montana/ northeastern Wyoming area during the coming 25 years.

Estimating average seam thickness at 40 feet, commulative land disturbance during this period will be roughly 220 square miles, assuming 90% coal recovery, with a commulative coal production of roughly 9 billion tons from this region. This production is equivalent to 15% of the strippable coal reserves of Montana and Wyoming, to 4.5% of their total reserves and 2.6% of their combined resources.[31] Very clearly, then, environmental and institutional problems associated with rapidly expanding the Western coal industry will form the crux of any problems in attaining these supply levels; the coal resource base will hardly be touched during this period.

B. Coal Transportation

The rapid expansion anticipated in coal production, especially in the western regions, will demand an even greater increase in the capacity of the transportation industry to ship coal. The distribution patterns generated for 1985 and 2000 suggest that average coal transport distances will increase as utilities tap distant sources of low-sulfur coal. Since most "new" sources of low-sulfur supplies are located in the Rocky Mountains it is apparent that the railroads will carry the bulk of this increased traffic.

While the geographic aggregation employed in our methodology tends to overestimate the distances of actual coal shipments we felt that it would be useful to apply a crude "fix" on these shipments to obtain a first-order estimate of the magnitude of these increased service requirements. Accordingly, actual 1975 utility coal shipments as reported by the Federal Power Commission[32] were aggregated on the basis of our supply and demand regions and the "average" shipping distance was computed. This estimate was then compared with the actual 1975 averaged distance; our estimated distance was 460 miles while the actual average distance for 1975 was roughly 325 miles.[33] This discrepancy was attributed both to the presence of minemouth power generation, which we did not model, and to our assumption that interregional coal shipments would be more likely to terminate at locations within each demand region closest to its coal source, as discussed at the beginning of this Chapter.

We were unable to obtain actual shipping distance at the regional level of our analysis; it is unclear whether regional variations exist which might bias our fix as the proportion of utility supplies originating in the western fields increases. The western demand regions are geographically larger than the eastern regions; this would suggest that the bias introduced in routing all shipments to the demand centroids would tend to overestimate the average distance of interregional shipments. On the other hand, the remote location of the Northern Great Plains coal fields would suggest that a substantially smaller fraction of interregional generation will take place at the minemouth in these regions than in the East. Without clear evidence as to either the magnitude or the direction of any bias so introduced it was decided to supply a correction of 135 miles (the difference between actual and calculated 1975 average distances) to all coal shipments generated by the model for the purpose of estimating the aggregate increase in coal transportation demands.

Table 14 displays our estimates of the demands placed on the transportation system for satisfying utility coal requirements in 1975, and for the distribution patterns generated for 1985 and 2000. The estimates were disaggregated into shipments originating east and west of the Mississippi River to capture the particularly heavy transportation requirements which will be placed on Western railroads.

It is apparent from this Table that the average length of utility coal shipments may be expected increase substantially during

TABLE 14

ESTIMATED TRANSPORTATION DEMANDS
FOR UTILITY COAL SHIPMENT: 1975, 1985, AND 2000

REGION	YEAR	UTILITY DEMAND (10^6TONS/YR)	AVERAGE SHIPMENT DISTANCE (MILES)	TON-MILES OF COAL SHIPMENT ($X10^9$)
EASTERN*	1975	332.4	280	93
	1985	475	210	100
	2000L[1]	555	260	145
	2000H[2]	575	260	150
WESTERN*	1975	87.8	500	44
	1985	340	730	250
	2000L[1]	600	760	460
	2000H[2]	580	730	420
TOTAL U.S.	1975	420.2	325	137
	1985	820	425	350
	2000L[1]	1155	520	605
	2000H[2]	1155	495	570

*"Eastern" includes the Appalachian and Midwestern Fields.

"Western" includes the Gulf, Northern Great Plains, Rocky Mountain and Southwestern Fields.

[1]Low Synfuel Production Case (4.5 Quads Total).

[2]High Synfuel Production Case (9.0 Quads Total).

the coming 25 years. This is a reasonable conclusion, given the rapid increase in utility demand for western coal.

Most noteworthy is the meteoric increase in western coal traffic, where our supply estimates show a 4-fold increase in tons shipped to utilities by 1985 and nearly a 7-fold increase by 2000. In terms of ton-miles of coal traffic, the increase is even greater: 6-fold by 1985 and 10-fold by 2000. Assuming all shipments originating in the west move exclusively via rail, utility coal shipments in 1975, 1985, and 2000 were estimated to generate $0.5, $3.5, and $7.5 billion in revenues, respectively, all in 1975 dollars.

Most of this increase, again, is due to the West North Great Plains supply region, where shipments to East and West Central utilities account for 63% of western tons shipped to utilities and 71% of western ton-miles in 1985, and 17% of the tonnage and 82% of utility ton-miles in 2000. These estimates imply that unit trains carrying 10,000 tons each must depart from the Powder River Basin every 24 minutes in 1985 and every 12 minutes in 2000 to supply these demands alone. To supply these coal requirements in 1985 unit trains would have to depart for the East Central and West North Central Regions hourly, and to the West South Central every two and a half hours. For 2000, these demands would require unit trains to depart at 25, 35, and 90 minute intervals, respectively. Were each of these shipments to take place along its own dedicated track an individual living along the "east central route" would see 48 unit trains per day by 1985 and 119 per day in 2000. Someone living along the "west north central route" would see 51 trains daily in 1985 and 83 in 2000, and our third citizen, living near the "west south central route" would see 20 trains daily in 1985 and 32 daily in 2000. Obviously, there are numerous route options for shipping coal to each of these regions, but the delay, the visual and rural impacts, and the physical hazards of an increasing number of unit train passages will impose very substantial external costs to residents along these routes. This is particularly true because many western towns and cities have built up around railroad lines for the same reasons many eastern cities developed around harbors; the railroads provide them with a critical commercial link to the rest of the country.

In this context, consider the nature of the slurry pipeline's challenge to the railroads for western coal. The $7.5 billion in 2000 coal revenues is roughly equal to the combined revenues of the Union Pacific, Burlington Northern, Southern Pacific, and Santa Fe railroads. Between 1960 and 1970 rail ton-miles of all commodities increased 1.1% annually,[36] with coal accounting for roughly 15% of total ton-mileage. Were this 1.1% growth rate for all other rail-hauled commodities to remain constant between now and 2000, the coal shipment growth estimated here would more than double this rate, and coal would account for approximately 30% of rail shipment by 1985, and 40% by 2000.

These figures should not be taken as more than order of magnitude estimates; however, they suggest that even if coal shipments expanded only half as rapidly as projected here, coal would still represent a tremendous growth opportunity for the railroad industry, and for the western companies in particular.

In light of these considerations, it is difficult to understand the rationale for precluding free competition for coal transportation by other modes, specifically, by the slurry pipeline industry. The economics of scale for slurries are such that railroads can readily compete with any but the longest, largest capacity lines; if the pipelines should turn out to be as costly and problem-ridden as their detractors claim, operating experience in the market will bear them out. If slurry proponents are correct, a healthy intermodal competition will emerge, from which energy users can only benefit.

A related question is that of the adequacy of the transportation system to handle the increased demands placed on it by a program of accelerated coal supply. This is a difficult question to answer definitively because "adequate" is not an absolute term but refers to some nebulous level of diseconomy beyond which a capital investment in say, track upgrading or increasing waterway lock capacity is more than fully compensated by reduced system costs to all shippers. While a thorough analysis of this question was not undertaken, the Manalytics study[34] discussed in Section IV-C applied two widely divergent coal supply scenarios to determine the response to potential rail "bottlenecks." Although our supply estimates were too different from the scenarios developed in the Manalytics report for a direct comparison with their results, a comparison of interregional flows was made with the available capacities across their barriers. The flows across these barriers approached 50% of the indicated available capacity for the Missouri and Mississippi Rivers for the 2000 low synfuels scenario, and were well below that figure elsewhere. This provides tentative support for the conclusion that the "macro" rail system would not be taxed unduly by the coal distribution patterns generated for 1985 and 2000. On the other hand, in order to mine the quantities of coal indicated in the supply forecasts for the West North Great Plains region, additional rail will undoubtedly have to be added near the Powder River; the companies' petition to add this track is currently under environmental review.

C. Coal Demand

This section examines the impact an expanding synthetic fuel industry may exert on coal consumption patterns during the coming

25 years and will examine the implications that the regional variations in low sulfur coal availability may have in altering the pattern of future coal distribution.

The most notable feature of the regional synfuel production patterns displayed in Table 15 is the voracious "appetite" this industry displays for low cost coal. This is especially true of the synthetic liquids industry, and true to a lesser extent for the synthetic pipeline gas industry, where proximity of the coal field to the existing pipeline network seems to be equally important. Two factors explain this behavior and point out fundamental economic factors which will certainly influence the regional development of the "real" industry. First, the synthetic fuels industry needs to purchase substantially more than a million Btu of coal to produce a million Btu of synthetic fuels. Thus, the synthetic fuels industry will perceive a "multiplier effect" on their production costs equivalent to the reciprocal of their plant's thermal efficiency; these multiplier factors will be roughly 1.33 for low-Btu gas producers, 1.5 for the synthetic liquids industry, and 1.61 for high-Btu gas plants. Where a utility or industrial coal user would see a 10¢ per million Btu difference in two coal sources, the synthetic fuels industry would see a 13 to 16¢ difference and might be expected to bid more aggressively. Interestingly enough, the industrial sector, rather than the utility sector is the chief victim of this competition; their less stringent sulfur requirement places them in head-to-head competition with the synfuels producers for the less costly high sulfur supplies. Even in the 2000 synthetics scenario industrial coal users in the Western Central regions imported roughly 45% of their requirements from Southern Appalachia, since the synfuels industry "captured" all more convenient sources.

TABLE 15

1985 and 2000 Regional Synfuels

Production-10^{12} Btu Produced (% of Synfuel Total)

	Sulfur Content	1985 Low Btu*	1985 High Btu	1985 LIQUIDS	2000: LOW SYNFUELS Low Btu*	2000: LOW SYNFUELS High Btu	2000: LOW SYNFUELS LIQUIDS	2000: HIGH SYNFUELS Low Btu*	2000: HIGH SYNFUELS High Btu	2000: HIGH SYNFUELS LIQUIDS
North Appalachia	HIGH	500 (100)	170 (34)		1193 (80)	170 (8)		1943 (65)	170 (4)	
South Appalachia	HIGH							326 (11)		
Midwest	HIGH			100[1] (100)	307 (20)	1137 (57)	100[1] (100)	831 (24)	1662 (42)	100[1] (5)
Gulf	HIGH									73 (4)
East North Great Plains	LOW					153 (8)			341 (9)	
	HIGH		53 (11)			82 (4)			82 (2)	18 (1)
West North Great Plains	LOW		190 (38)			338 (17)	600 (60)		1313 (33)	1661 (83)
	HIGH					32 (2)				69 (3)
Rocky Mountain	LOW									
Southwest	LOW								66 (2)	
	HIGH		87 (4)				300 (30)		365 (9)	75 (4)
TOTAL		500 (100)	500 (100)	100 (100)	1500 (100)	2000 (100)	1000 (100)	3000 (100)	4000 (100)	2000 (100)

*Low Btu gas production was constrained to the Ohio River Valley, as described in Chapter III.

[1]This plant, assumed to be a test facility was placed in the Midwest exogenously.

The second significant factor which will influence the regional development of the synfuels industry is the widely differing costs they will bear in transporting their products to distant markets. While the production costs clearly favor locating synfuel plants in the west, the existence of substantial production capacity for natural gas and oil in the Rocky Mountain and West Central regions, coupled with the anticipated completion of Alaskan transportation networks, leads to the conclusion that there will continue to be a glut of fossil fuels in these regions. Either the synfuels or the conventional production they displace will have to be shipped Eastward to energy deficient demand regions. Since little pipeline capacity exists between these regions it seems likely that new pipeline capacity would need to be built even as the existing pipeline arteries utilization dropped due to declining Gulf Coast production. A consortium of synthetic high-Btu gas producers considering the installation of 1 billion SCFD of capacity and a 1000 mile 30" pipeline to Chicago by 2000 would fact supplemental transportation charges of 65¢ per million Btu, as seen in Table 5 . A similar consortium in the Gulf supply region, using the currently in-place network would face interregional transport costs of 39¢ per million Btu and a consortium in the midwest might face effectively no transport charges, assessing only distribution charges to their production costs. This means that midwestern coal would be "worth" roughly 40¢ per million Btu more than West North Great Plains coal, and 24¢ more than Gulf lignite, other costs being equal, for this particular application.

Coal liquefaction consortia in these three regions contemplating building similarly sized liquefaction facilities would face interregional transportation charges (to Chicago) of 15¢, 9¢, and, of course, 0¢ for the midwestern location. For this purpose, midwestern coal could command no more than 6¢ per million Btu over Gulf coal and roughly a 9¢ premium over the Powder River coal.

This reasoning leads to the conclusion that a coal liquefaction industry would locate heavily in the low-cost Western coal supply regions and that a high-Btu gas industry would be expected to disperse more geographically, based on both the regions' economic distance from natural gas suppliers and on the basis of its coal extraction costs. In fact, this occured in the three distributions analyzed. Table 15 displays the regional fraction of each synthetic fuel type for 1985 and the two synfuels production levels for 2000. In all these cases it can be seen that 100% of the coal liquefaction capacity, with the exception of the single plant exogenously located in the midwest, was located west of the Mississippi River. Conversely, high-Btu gasification was split evenly between the east and west with low-Btu gasification constrained to heavy industrial use along the Ohio River.

It is important to note that these synfuel production levels were "forced" into the solutions--their estimated costs of $3.50-$4.00 per million Btu were substantially above all other supplies of these fuels with the sole exception of imported liquefied natural gas (LNG) from overseas. While Alaskan gas and Atlantic Outer Continental Shelf gas supplies were assumed to supply 1.75 quads during this period, other potential supplies exist which could radically alter these synfuel distributions and dramatically dim the short-term prospects for a coal gasification industry. Some experts believe that enormous natural gas reserves are trapped in "tight" formations, and that this gas could be profitably extracted at about $3.00 per million Btu--well below the least expensive synthetic high-Btu source. Appendix A of this report investigates the emerging synfuel technologies currently under development which may enter the commercial realm in the next 25 years, with special emphasis on the status of the various coal synthetic processes.

Tables 16 and 17 display the average delivered cost of coal to utilities and industrial coal users in each region calculated from the model allocations. The utility estimates were compared with actual 1975 data computed by the FPC,[35] but a similar baseline could not be established from which to judge industrial estimates. These costs represent an average annual increase in the real cost of coal of roughly 1.6% annually for both sectors between 1985 and 2000. The higher 3.0% annual rate of increase in utility coal prices between 1975 and 1985 was felt to represent the costs of bringing coal-fired utilities into compliance with Federal New Source Performance Standards, so this high cost increase was not felt to be significant.

Figure 12 displays our estimate of the costs of base-load electric generation using coal or nuclear power in the nine demand regions for 1985 and 2000. Coal-fired generation costs were developed on the basis of $445 per kilowatt, $0.76 per kilowatt-hour O&M expenses, a 70% capacity factor and the average coal costs to each region generated by the model allocations. Environmental control costs were estimated at 50¢ per million Btu of high-sulfur coal entering the boiler. Thermal efficiency was assumed to be 34%.

Nuclear costs were estimated on the basis of $585 per kilowatt, $0.35 per kilowatt-hour O&M, $0.65 per million Btu fired charges, and 33% thermal efficiency. A fixed charge rate of 15% was assumed for both plant types. There has been a great deal of concern about the reliability of nuclear power plants. Accordingly, nuclear power costs were estimated at the current average capacity factor of 55%, and also at a 70% factor, reflecting benefits from learning phenomena and design standardization which <u>may</u> improve nuclear reliability in the future.

TABLE 16

AVERAGE DELIVERD COST OF COAL TO UTILITIES

BY REGION, 1975, 1985 and 2000

(1975 $\$/10^6$ BTU)

	1975[1]	10^{12} Btu	1985	10^{12} Btu	2000 Low Synthetics	2000 Accelerated Synthetics	10^{12} Btu
NEW ENGLAND	1.24	38	1.35	88	1.75	1.75	128
MIDDLE ATLANTIC	1.02	1067	1.26	2343	1.61	1.60	3609
SOUTH ATLANTIC	1.00	1878	1.24	2684	1.60	1.60	3207
EAST NORTH CENTRAL	.82	3124	1.12	3858	1.31	1.34	4200
EAST SOUTH CENTRAL	.80	1570	1.15	1539	1.45	1.45	1751
WEST NORTH CENTRAL	.60	836	.88	1631	1.02	1.02	2432
WEST SOUTH CENTRAL	.23	120	.97	772	1.24	1.24	1196
ROCKY MOUNTAIN	.32	628	.62	745	.80	.80	965
PACIFIC	.56	68	.96	212	1.30	1.30	600
NATIONAL AVERAGE/TOTAL	.81	9329	1.11	13872	1.37	1.38	18088

[1] FPC Cost and quality of fossil fuels deliverd to steam electric power plants, 1975

TABLE 17

AVERAGE DELIVERED COST OF COAL TO NON-COKING INDUSTRIAL CONSUMERS-BY CENSUS REGION, 1985 and 2000 (1975 ¢/10^6 Btu)

	1985	10^{12} Btu	2000 Low Synthetics	10^{12} Btu	2000* High Synthetics
NEW ENGLAND	92	34	120	52	120
MIDDLE ATLANTIC	83	602	108	877	108
SOUTH ATLANTIC	86	512	111	895	111
EAST NORTH CENTRAL	75	1218	96	1840	96
EAST SOUTH CENTRAL	83	8343	107	588	107
WEST NORTH CENTRAL	87	276	116	477	116
WEST SOUTH CENTRAL	53	284	91	854	85
ROCKY MOUNTAIN	64	97	85	210	85
PACIFIC	106	90	130	240	130
NATIONAL AVERAGE/TOTAL	79	3456	102	6033	102

*Supplies from all coal regions were increased 15% to accommodate these demands.

Figure 12 suggests that, under previous SO_2 standards, coal (except at the minemouth) will only be marginally cost competitive with nuclear power in the Atlantic regions. In the East Central regions, coal generation is seen to be less costly than nuclear generation at the current nuclear reliability level, but more costly should new nuclear plants improve substantially in reliability. Finally, throughout the West, coal-fired generation is seen to be substantially less costly than current nuclear operations, and cost-competitive with nuclear even at a 70% capacity factor. These regional costs all refer to coal satisfying New Source Performance Standards for sulfur dioxide (1.2 lbs $SO_2/10^6$ Btu).

Legislation was recently enacted to require that the best available control technology (BACT) be installed on all new coal-fired power plants. In order to investigate the impact of BACT on the utility industry the utility distribution patterns were re-generated assuming that FGD would be required on all plants. The premium assigned by PIES to eastern low-sulfur coal was eliminated, and reduced supplies of these coals were estimated from the PIES coal supply curves. Utility distribution patterns were recomputed as shown in Tables B-15 and B-17, unconstrained by competition from other modes. The regions' incremental costs for coal-fired electric generation under this environmental scenario are displayed by the shaded areas in Figure 12. These increments should be thought of as minima since competition from industrial and synfuel coal users could only drive the average price up.

In examining these increments it may readily be seen that adopting BACT would have essentially no impact on the cost of coal-fired generation in the Atlantic regions (since the premium on eastern low-sulfur coal effectively discounts the FGD charge), a moderate increase in East Central regions, and a heavy impact in

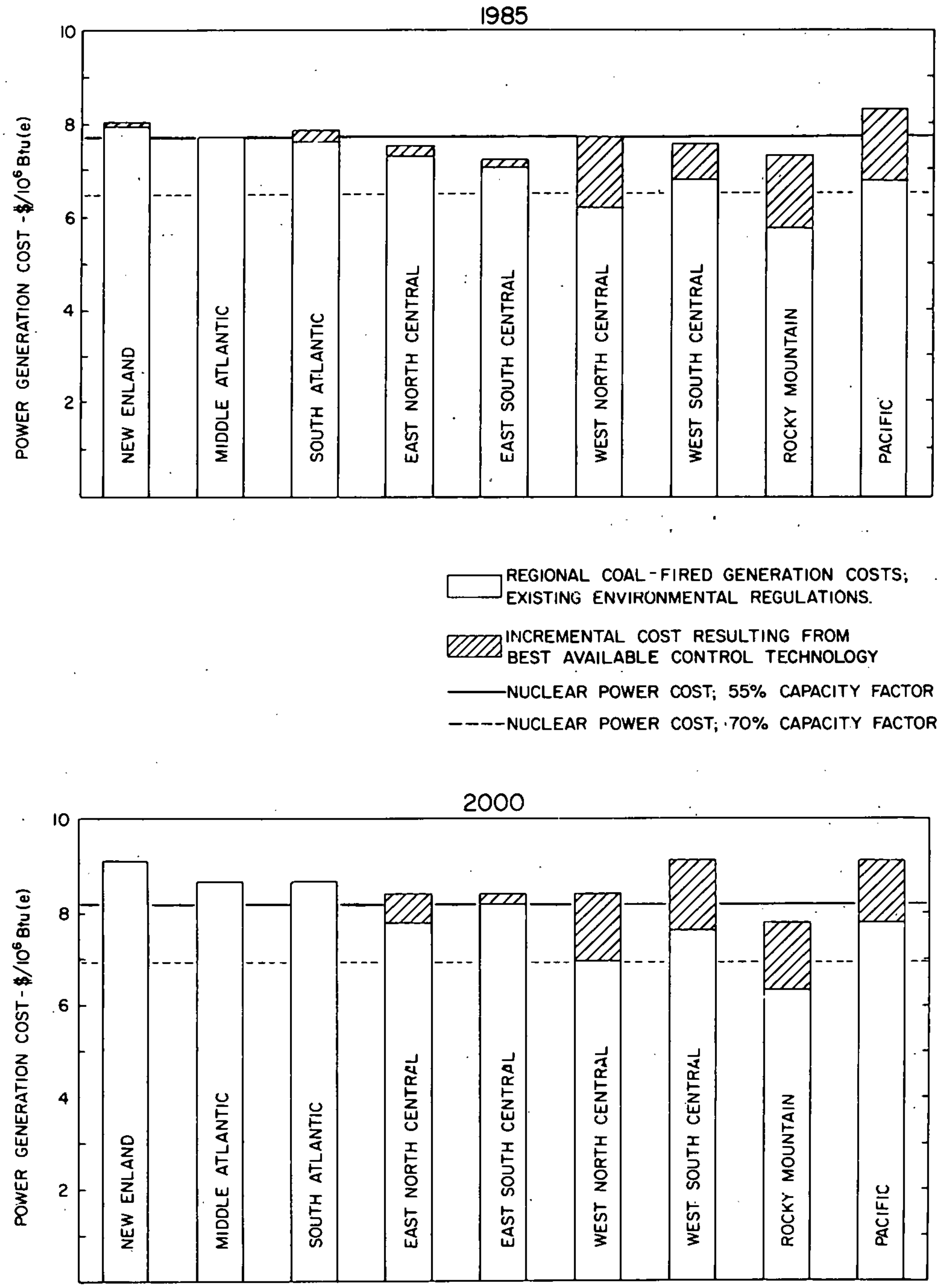

Figure 12. Comparison of coal fired and nuclear power costs under existing and proposed environmental regulations.

the west, which, under existing standards, would burn low-sulfur western coal exclusively.

Looking at the interfuel effects, the impact of BACT is seen to eliminate coal's cost advantage over nuclear power in the west, and to induce a bias toward nuclear plant construction nationwide.

One clear advantage of BACT is that it would tend to reduce sulfur emissions from coal-fired power plants. To examine this effect, uncontrolled and scrubbed sulfur emissions were estimated regionally from the BACT scenarios, and original emissions under existing regulations were computed from the model runs. For this purpose, all low sulfur coal was assumed to have a sulfur content of 0.6 lb/10^6 Btu. High sulfur coal contained sulfur typical of its supply region.

The overall impact of adopting BACT is seen to have three parts. First, it may be expected to induce a bias among utilities away from tapping distant sources of low-sulfur coal in favor of locally available resources. Secondly, it has the tendency to raise the cost of coal-fired electricity, thereby inducing an economic bias among utilities toward nuclear generation. Finally, it has the benefit (as intended) of reducing sulfur emissions from power plants.

Figure 12 demonstrates that the costs of adopting BACT will tend to fall most heavily on western utilities. An obvious question arises as to whether the benefits of reduced sulfur emissions justify these costs.

To examine this question, optimal utility coal distribution scenarios were generated for NSPS environmental regulations and BACT regulations looking solely at utility requirements in the nine demand regions. These are shown in Tables B-16 to B-19. The regional costs and average emissions of the NSPS and BACT distribution patterns were computed from these patterns, and compared with those resulting from a "No Control" strategy to estimate the region-specific costs of obtaining lower emissions. The No-Control scenario is identical to the BACT scenario, except that the costs and sulfur emission reductions of the FGD systems were eliminated. The resulting comparisons are displayed in Tables 18 and 19.

Looking first at the national totals the surprising conclusion is seen that instituting BACT would add an average of only 14¢ to the utilities' cost of coal and environmental control in 1985 and 20¢ in 2000. However, the incremental costs of 56 and 69¢ per pound sulfur removed are above the North and Merkhofer damage estimate of 46¢ per pound sulfur emitted for an urban power plant, but well within its confidence interval. This low incremental coal cost results from the shift of utility expenditures from coal shippers to post-combustion environmental control systems as a result of switching to local high sulfur coal resources.

Looking at the various regions, however, it becomes abundantly clear that these emission control costs would not be borne uniformly, but would fall heavily on the western states, which tend to be more rural and which have minimal sulfur dioxide problems. The Atlantic Coast region is seen to benefit slightly from BACT, with an estimated 12% reduction in emissions available "at no cost" relative to existing environmental standards.

The nation's most serious sulfur-related air quality problems occur in the heavily industrialized Ohio River Valley, most closely associated with the East North Central region. Here, BACT is seen to result in only a 5 to 7% reduction in emissions at incremental costs of \$2.00 to \$6.67 per pound removed, far in excess of current damage cost estimates. This is a direct result of the extremely high sulfur content of local (miswestern) coal reserves.

This discussion should not be taken as predictive in any absolute sense of the word. Tremendous uncertainty exists as to the

Table 18

Average Utility Costs and Emissions Resulting from Various Environmental Control Strategies: 1985[1]

	Utility Coal Demands (10^{12} Btu)	Control Strategy	Average Cost[2]	Average Emission (lb S/10^6 Btu)	Sulfur Removal Cost ($/lb)	
					Average	Increments[(6)]
New England	88	N.C.[3]	.86	1.92	--	
		NSPS[4]	1.36	.42	.33	
		BACT[5]	1.36	.41	.33	0
Middle Atlantic	2343	N.C.	.76	1.92	--	
		NSPS	1.26	.42	.33	
		BACT	1.26	.41	.33	0
South Atlantic	2684	N.C.	.80	1.15	--	
		NSPS	1.22	.51	.66	
		BACT	1.30	.23	.54	.39
East North Central	3858	N.C.	.71	1.67	--	
		NSPS	1.12	.59	.38	
		BACT	1.21	.55	.45	2.00
East South Central	1539	N.C.	.70	1.67	--	
		NSPS	1.18	.42	.38	
		BACT	1.20	.31	.37	.18
West North Central	1631	N.C.	.76	.67	--	
		NSPS	.88	.58	1.33	
		BACT	1.26	.13	.93	.84
West South Central	772	N.C.	.72	1.19	--	
		NSPS	.95	.60	.39	
		BACT	1.22	.24	.53	.75
Rocky Mountain	745	N.C.	.62	.60	--	
		NSPS	.62	.60	--	
		BACT	1.12	.12	1.04	1.04
Pacific	212	N.C.	.96	.60	--	
		NSPS	.96	.60	--	
		BACT	1.46	.12	1.04	1.04
U.S. Total	13872	N.C.	.74	1.40	--	
		NSPS	1.10	.53	.41	
		BACT	1.24	.28	.45	.56

[1] Basis: Tables B-15 and B-16.

[2] Includes the delivered cost of coal and SO_2 removal costs (at 50¢/million Btu) where required. Costs are in 1975 dollars per million Btu.

[3] No SO_2 controls.

[4] Existing New Source Performance Standards.

[5] Proposed Best Available Control Technology.

[6] Increment is $\left(\frac{\text{BACT cost - NSPS cost}}{\text{BACT emission - NSPS emission}}\right)$

Table 19

Average Utility Costs and Emissions Resulting from Various Environmental Control Strategies: 2000[1]

	Utility Coal Demands (10^{12} Btu)	Control Strategy	Average Cost[2]	Average Emission (lb S/10^6 Btu)	Sulfur Removal Cost ($/lb) Average	Increments(6)
New England	128	N.C.[3]	1.12	1.92	--	
		NSPS[4]	1.74	.43	.42	
		BACT[5]	1.74	.38	.41	0
Middle Atlantic	3609	N.C.	.98	1.92	--	
		NSPS	1.60	.43	.42	
		BACT	1.60	.38	.41	0
South Atlantic	3207	N.C.	.95	1.11	--	
		NSPS	1.54	.49	.94	
		BACT	1.57	.22	.70	.11
East North Central	4200	N.C.	.89	2.85	--	
		NSPS	1.31	.60	.19	
		BACT	1.51	.57	.27	6.67
East South Central	1751	N.C.	.88	.87	--	
		NSPS	1.40	.60	1.93	
		BACT	1.50	.17	1.03	.23
West North Central	2432	N.C.	1.02	.60	--	
		NSPS	1.02	.60	--	
		BACT	1.52	.12	1.04	1.04
West South Central	1196	N.C.	1.24	.60	--	
		NSPS	1.24	.60	--	
		BACT	1.74	.12	1.04	1.04
Rocky Mountain	965	N.C.	.80	.60	--	
		NSPS	.80	.60	--	
		BACT	1.30	.12	1.04	1.04
Pacific	600	N.C.	1.25	.60	--	
		NSPS	1.25	.60	--	
		BACT	1.75	.12	1.04	1.04
U.S. Total	18088	N.C.	.94	1.31	--	
		NSPS	1.35	.55	.54	
		BACT	1.55	.26	.58	.69

[1] Basis: Tables B-18 and B-19.

[2] Includes the delivered cost of coal and SO_2 removal costs where approximate. Costs are in 1975 $ per million Btu.

[3] No SO_2 controls.

[4] Existing New Source Performance Standards.

[5] Proposed Best Available Control Technology.

[6] Increment is $\left(\frac{\text{BACT cost} - \text{NSPS cost}}{\text{BACT emission} - \text{NSPS emission}}\right)$

actual costs of SO_2 removal, and there is a growing body of experimental data which suggests that costs of SO_2 removal are positively correlated with the coal sulfur content. Additionally, as before, these distribution patterns ignore the commitments for coal supply made by existing plants. Nevertheless, they present a perspective on the regional costs and benefits of adopting BACT which suggest that:

1. The west would receive substantial emission reductions, but at a cost between 2 to 6 times higher than current damage (benefit) estimates.

2. The East North Central, currently experiencing the nation's most serious sulfur-related air quality problems, would reduce its emissions 1 to 4% more than under existing New Source Standards, but at a cost 5 to 15 times greater than estimated benefits.

3. The remainder of the east would reduce emissions between 1 to 55% at costs substantially lower than currently estimated benefits of doing so.

This analysis is, admittedly, quite superficial. The apparent benefits to certain eastern areas resulting from BACT implementation, however, suggest that room for improvement exists in the New Source Performance Standard system.

BACT will spur the use of midwestern coal, will depress the prospects for western coal development, and may stimulate the outlook for nuclear power, despite the problems presently associated with it.

D. Synthetics Market Penetrations

The bulk of this work preceded the release of the President's Energy Program in April 1977. One of the major points of the program is the phaseout of natural gas and petroleum in the industrial and utility sectors by added taxes to those sectors, and tax credits for conversion of equipment to coal use.

This will prove very critical, should Congress legislate this program into existence, as a stimulus for a coal conversion synthetic fuels program. Instead of synthetic fuel economic competitiveness being linked to external market price mechanisms, this energy policy immediately speeds up the process, compressing the time periods anticipated for market penetration. Instead of 2000 as a target year, 1985 could see low Btu gas cheaper than natural gas and oil to industry, with synthetic natural gas and coal liquids approaching rapidly the area of competitiveness. Of course, this program could also increase coal demand and prices accordingly, but with all other things being equal, this should have much less of an effect than the energy taxes on gas and liquid fuels from natural sources.

REFERENCES

1. Federal Energy Administration. 1976 National Energy Outlook: February 1976.

2. Ibid., p. 203.

3. Project Independence Blueprint. Report of the Inter-Agency Coal Task Force. Federal Energy Administration, March 1974.

4. Brookhaven National Laboratory. Regional Reference Energy Systems. EPRI EA-462, June 1977.

5. Bureau of Mines. 1973 Mineral Yearbook.

6. Coal Age, August 1976, p. 87.

7. EPA Proceedings: Symposium on Flue-Gas Desulfurization. Environmental Protection Agency, EAP-600/2-76-136a, March 1976.

8. The MITRE Corporation. Analysis of Steam Coal Sales and Purchases. FEA, April 1975.

9. Rand McNally & Co. Handy Railroad Atlas of the United States. 1973.

10. American Commercial Barge Line Co. Inland Waterway Mileage Guide. March 1969.

11. Nagarvala, Olver, & Ferrel. Regional Energy System for the Planning and Optimization of National Scenarios. The Bechtel Corporation. June 1976, FE 1552-18, p. 101.

12. Ibid., p. 96.

13. Rierer, Michael, and Sod, Shao Lee. Route Specific Cost Comparisons: Unit Trains, Coal Slurry Pipelines and Extra High Voltage Transmission. University of Illinois (Center for Advanced Computation), CAC #190, May 1976.

14. Bureau of Mines. Bituminous Coal and Lignite Distribution--1970.

15. Time, Inc. The Fortune Double 500 Directory. 1976.

16. Manalytics, Inc. Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond. EPRI EA-237, September 1976.

17. Ibid., p. 6.

18. Op. cit. (11), p. 101.

19. Op. cit. (13), pp. 61-83.

20. Op. cit. (13, p. 63.

21. Energy Daily. October 4, 1976, p. 4.

22. Op. cit. (11), p. 101.

23. Op. cit. (13), pp. 87-106.

24. Federal Power Commission. 1970 National Power Survey. Volume IV.

25. Op. cit. (11), p. 107.

26. Ibid., p. 108.

27. As per ERDA SF-2 estimates.

28. Ibid.

29. North, D. W., and Merkhofer, M. W. Analysis of Alternative Emission Control Strategies. Air Quality and Stationary Source Emission Control, Committee on Public Works, U.S. Senate, # 94-4, March 1975.

30. Federal Power Commission. Annual Summary of Cost and Quality of Steam-Electric Plant Fuels (1975). Staff Report, Bureau of Power, May 1976.

31. Battelle Pacific Northwest Laboratory. The Regional Analysis of the Electric Power Industry. Volume 4a, Coal Resource, BNWL B-415 V4a, April 1975.

32. Op. cit. (30).

33. Op. cit. (16), p. 15, It was Estimated that Expansion of Western Mining Increased the 290 Miles Estimated by Manalytics for 1973 to 325 in 1975.

34. Ibid.

35. Op. cit. (30).

36. Project Independence Blueprint. Transport of Energy Materials: Volume I, p. II-7.

APPENDIX A

CHARACTERIZATION OF COAL TECHNOLOGIES AND STATUS OF DEVELOPMENT

INTRODUCTION

The use of coal in the past decades has been declining relative to other fuels in almost every area of fuel consumption. The reason for this trend is understandable. Because it is solid and contains substantial amounts of waste, coal use involves difficulty at every stage. It is much more difficult to transport and handle than either oil or gas, releases pollutants to the atmosphere at the time of combustion, and also leaves residue in the form of ash after combustion that creates disposal problems. In addition, coal in its natural form is clearly the least flexible of all fossil fuels.

Now that the demand for liquid and gaseous fuels has surpassed our supply capability without excessive imports, we must make greater use of coal--our largest single fossil fuel resource. The potential for coal development is virtually unlimited provided constraints to its transportation and use can be mitigated to acceptable socio-economic limits. However, its expanded use is subject, like any other fuel, to available technology and real economic cost relative to other fuels. In this Appendix some of the technologies, presently available and/or looming at the horizon, are discussed and major capital, labor and material constraints, if any, affecting the implementation of these technologies are outlined. These technologies can be divided into two categories--one related to energy supply and the other to end use. In the supply category technologies such as coal gasification, liquefaction, etc. are included while fluidized bed, fuel cell, etc. are classified under end use category.

I. SUPPLY TECHNOLOGIES

Synthetic Fuels From Coal

Processes for making gaseous and liquid synthetic fuels from coal have been available for many years. While some of these processes have been proven to be technically feasible, none has yet been able to produce products that compete favorably with the production costs of conventional oil and gas. The political and economic ramifications of 1973 have stimulated interest in synfuel conversion but there remain major uncertainties to be overcome before a self-sustaining industry can be established. Although there are a number of synthetic fuels projects being planned, none has actually proceeded to construction. Sufficient operating experience has not been gained at the pilot plant scale to insure the technological viability of a commercial plant. With the current uncertainty of these technologies, there is little chance that a commercial plant will be constructed without federal subsidization.

Overview of Technologies

a. Low/Medium Btu Gas:

Low/medium Btu gas/is a promising method for using high sulfur coal as a utility and/or industrial fuel in an environmentally acceptable manner. It has potential for use in existing oil and gas fired boilers via retrofitting and in fueling gas-fired boilers via retrofitting and in fueling gas-fired combined cycle power plants. It can also be used as furnace/oven fuel for process heat as well as for industrial nonfuel applications such as ore reduction, as a reducing agent for process metallurgy, and as a synthesis gas for chemical feel stock and methanol production.

The technology for production of low/medium Btu gas is well developed and is currently applied in many commercial plants outside the United States. Of all the synfuel processes low/medium

Btu gas production involves the least technical risk and can be inplemented in the shortest period of time.

The basic gasification process involves the pyrolysis of coal in a steam environment. During initial heating the coal devolatilizes and the char thus produced reacts endothermically with steam to produce carbon monoxide and hydrogen. The heat required for maintaining the thermal balance is provided by combustion of a portion of the carbon utilizing either air or commercial oxygen as an oxidant. An advantage of gasifying high sulfur coal is that approximately 90% of the sulfur reacts with hydrogen to form hydrogen sulfide which can be effectively scrubbed from the flue gas by a number of commercially proven processes.

The gaseous product from an air-blown gasifier has a heating value of about 150 Btu/scf and is commonly referred to as low-Btu gas. The heating value of this gas is low because of the presence of about 50% elemental nitrogen which was introduced with the air. Low Btu gas is suitable for use as an energy source near its point of production because its low heat content makes it uneconomical to transmit long distances.

The gaseous product from an oxygen-steam blown gasifier has a heating value of about 300 Btu/scf and is commonly refered to as medium Btu gas or synthesis gas. This gas can be piped economically for use within about 25 miles of the gasification plant. Since the gas is practically nitrogen free and can be readily purified to yield a gas containing hydrogen and carbon monoxide it can be used as a synthesis gas for the production of chemicals such as ammonia and methanol.

Three processes considered practical for significant production of low/medium Btu gases by 1985 are:

Lurgi Process:

This is the most extensively developed fixed bed type coal gasification process. In the basic Lurgi process a relatively coarse coal feed is introduced at the top of the reactor and gravitates through the reactor in the presence of a slow-moving counter current flow of reaction gases. The unit operates with an increasing temperature profile between the top devolatilization zone to the bottom combustion zone. As the devolatilized coal gravitates through the bed, it is gasified and the resultant ash is withdrawn from the bottom of the reactor. The performance of the gasifier is characterized by solids residence time in excess of one hour and by the presence of tars in the product gas due to the relatively low temperature at the top of the unit. As in any fixed bed gasifiers, caking coals pose agglomeration problems, although significant progress has been made in overcoming this. It is hoped that the problem will have been solved to permit the use of caking coals in fixed bed-type gasifiers in the 1980-1985 period.

Winkler Process:

This is the only fluidized bed gasifier process commercially available at present. The process involves feeding crushed coal (less than ½") into a fluidized bed reactor counter current to the upward flow of the gasifying medium. The velocity of this flow is maintained slightly above that required to merely support the coal particles. At this velocity, and because of the good gas-solids contact associated with the free movement of solids in the bed, heat is readily transferred and isothermal, uniform conditions exist. Gasification in the Winkler generator takes place at temperatures of 1500 to 1850 ^{o}F and atmospheric pressure. The high temperature provides for a tar-free product gas. Also, by operating at higher temperatures and smaller coal feed sizes, this gasifier has a higher gasification capacity per unit of reactor volume than that of fixed bed units. Subbituminous or lignite coal is preferred due to its higher carbon conversion.

Koppers-Totzek Process:

This process uses entrained bed gasification and is the only one with this bed type to be presently commercially available. In this case, pulverized coal of any type (screened to #200 mesh) and a steam/oxygen mixture are introduced at opposite ends of the refractory lined gasifier in such a manner that the solids are entrained and swept along with the gas. The small particle size provides for ease of entrainment and facilitates high rates of reaction. Since the raw coal fed into the unit is carried along at the velocity of the gas and because the particles are heated very rapidly through the plastic range, contact between particles is limited to occasional collisions. This minimizes the possibility of agglomeration and permits the use of caking coals. The high velocities involved result in extremely short solid residence time of less than 10 seconds. Complete gasification in this short period of time requires operating temperatures between 2700 and 3300^{o}F. Considerable combustion of coal is required to achieve this high temperature throughout the entire gaseous product stream. To minimize heat losses as sensible heat in the product gas, commercial oxygen, rather than air with its inert nitrogen, is used as the oxidant. The Koppers-Totzek process has the highest coal gasification capacity per unit volume of the three processes considered here and has the additional advantage of being able to use caking coals. In the present form, the process takes place at atmospheric pressure but Koppers-Totzek in conjunction with Shell is commercially available for operation at pressures up to 450 psi in the 1980-1985 period.

Future Development:

The thrust of low-Btu gasification research at present is concentrated in the following areas:

- Development of capability to operate with wider ranges of coals, specifically caking coals.
- Increasing gasification efficiency.
- Decreasing capital and operating costs of coal conversion processes in comparison with the existing technology.

The advanced gasifier concepts involve multiple stages, pressure operation, special ash agglomeration, or slagging techniques to facilitate ash removal and low carbon losses.

b. <u>High Btu Gas</u>:

Pipeline quality synthetic gas produced from coal has a wide range of potential applications as a replacement for fuel oil and natural gas for consumption in the industrial, residential, commercial, and electricity generation sectors. Even though no commercial sized plant is currently in operation, high Btu gas can be produced from coal by incorporating shift conversion and methanation steps into medium Btu gasification processes. Lurgi, Winkler, and Koppers-Totzek processes (discussed earlier) have been demonstrated commercially and could be used as the front end of the process to produce high Btu gas. Although methanation has not been used continuously on a commercial scale, it is predicted, based on commercial practices employed for the production of other end-products via shift conversion and methanation, that the process will pose no insurmountable technical problems. Following is a brief description of the presently available processes:

<u>Lurgi Process:</u>

In terms of process characteristics, Lurgi has the advantage of operating at high gasification pressures, because a significant amount of methane is produced in the gasifier reducing the level of methanation that must be conducted downstream.

The Lurgi gasifier was discussed in the previous section and will not be described here. Synthesis gas exits from the gasifier at a temperature of 850 to 950°F and a pressure of 300 to 400 psi. This gas, consisting of 11% methane, enters a quenching scrubber where a water spray is used to remove dust and cool the gas. Thereafter, roughly half of the gas is routed through a shift reactor whre carbon monoxide is catalytically shifted with steam to yield carbon dioxide and hydrogen. The shifted gas is then recombined with the raw gas stream and is cooled in a waste heat recovery unit where residual heavy hydrocarbons and unreacted steam are condensed. Purification of the gas is essential at this stage to protect the catalysts used in methanation. In the methanation step, the relatively pure gas is passed over a nickel-based catalyst; carbon monoxide and carbon dioxide combine with hydrogen to form methane and water. Finally heat is recovered from the gas product, residual carbon dioxide removed and the gas is dried. This gas has a methane content of 95 to 97% and residual quantities of carbon dioxide, carbon monoxide, hydrogen, nitrogen and argon.

The Lurgi gasifiers currently are the subject of development work to allow the use of caking coals and run-of-mine feeds, and to increase individual unit capacity.

Winkler Process:

Here again, the first step is to produce synthesis gas from coal, which is the same as the one described earlier. The gas exits the gasifier at approximately 1800°F and at atmospheric pressure and has relatively small (∿ 2%) methane content. The shift and methanation steps are essentially similar to ones described in the Lurgi process except that here, prior to shift conversion, the gas requires precompression to 300-450 psig.

Koopers-Totzek Process:

Coal gasification to synthesis gas, which is the first step, is again the same as discussed previously. The gas exits from the gasifier at $2700^{o}F$ and at atmospheric pressure, and has practically no methane. After cooling and scrubbing the synthesis gas of entrained solids, it is compressed to 300-450 psig prior to shift/methanation. In this case, unlike the Lurgi and Winkler processes, the shift conversion step is combined with the methanation step. The gas is humidified, partially shifted to adjust the H_2/CO ratio and then sent through a three-stage shift/methanation step. This combined step uses a special nickel catalyst which simultaneously promotes both the shift and methanation reactions. Part of the steam required by the shift reaction is provided by the methanation reaction, thus reducing the overall steam requirement.

An advantage of this process over the other two is the fact that the Koppers-Totzek gasifier is capable of handling any rank or size coal, caking or non-caking, high ash, char or coke withour pretreatment.

Second generation coal gasification processes are under development by DOE and by several industrial firms. These processes are expected to have a higher thermal efficiency and lower capital costs that first-generation designs both of which will help to reduce the cost of commercial manufacture of synthetic natural gas. It is possible, though not probable, that those developments may prooeed rapidly enough that some contribution to commercial supply may be made by 1985. These processes include Hygas, Synthane, Bi-Gas and CO_2 acceptor, and have been developed to the pilot plant stage. All these processes are based on the three basic coal gasifier designs discussed above but incorporate variations to improve the process efficiency and to achieve cost reductions. The main characteristics of two of these processes are discussed below.

Hygas:

The intent of the Hygas process is to maximize the production of methane directly from coal, therefore minimizing both the heat required in the gasifier and the volume of gases that must be cleaned and methanated. This is done with two coal hydro-gasification stages. In the first stage of the hydrogasifier, dried coal is heated rapidly by hot reaction gases rising from the second stage reactor and recycled hot char. Approximately 20% of the coal is converted to methane in the low temperature environment of the first stage. The second gasification stage is a high temperature fluidized bed reactor where an additional 20% of the initial coal is converted to methane in the hydrogen-rich environment. Of major technical and economic importance in this process is the production of the hydrogen rich gas required for hydrogasification. Three techniques for producing this gas are being investigated: steam-oxygen, electrothermal, and steam-iron. Results of preliminary economic studies suggest that the most economical source of supplemental hydrogen will be the steam-oxygen process, followed by the steam-iron process, then the electrothermal technique. This process is being developed by the Institute of Gas Technology (IGT) as part of the joint program of DOE and AGA.

Synthane:

The Synthane process was developed by the Bureau of Mines. A key feature of the Synthane process is that pretreatment of caking coals is integrated with the gasification process. Pretreatment provides a mild oxidation of the coal particle surface so the caking coals will not agglomerate in the gasifier. The hydrocarbon released during pretreatment is utilized integrally in the system, thereby maximizing the efficiency of coal conversion. Another feature of this process is that more than half of the methane is produced directly in the gasifier. By maximizing methane production in the gasifier, the sizes of all downstream process vessels are reduced by 30 to 50% compared to processes in which the raw gas from the gasifier contains little or no methane.

Cost estimates of production of high Btu gas and resource requirements and constraints to meet the implementation levels in the years 1985 and 2000 are discussed later in the Appendix.

c. Syncrude and Refined Coal Products:

The objective of these processes is to convert coal into a clean liquid fuel for use as a multipurpose fuel oil, and as a feed stock for refineries and the petrochemical industry. An advantage of coal liquefaction is that the entire range of liquid products, including fuel oil, gasoline, jet fuel, and diesel oil may ultimately be produced from coal by varying the type of catalysts and other operating conditions. Current emphasis, however, is being placed on the development of low sulfur, low ash fuel oil suitable for firing industrial and electric utility boilers and gas turbines.

At present, the Fischer-Tropsch process is the only commercially available technology and it is envisioned that the first coal liquefaction plants will be based on this technology. However this process has limitations because of its lower conversion efficiency (40%) and inability to use caking coals. To develop the most efficient utilization of coal resources, DOE is sponsoring the development of several advanced coal liquefaction processes, which are currently in different stages of development. Some of these, such as Solvent Refined Coal (SRC), the H-Coal and Char-Oil Energy Development (COED) processes, are in the pilot plant stage. These processes are capable of accepting midwestern and eastern caking coals, and offer the advantage of higher overall energy efficiency. Commercial sized plants based on advanced liquefaction technology can be onstream by early 1980's.

All liquefaction processes work on the same basic principle, namely, the addition of hydrogen to coal in some quantity to produce a desired liquid product. The greater the amount of hydrogen the lighter the product oil. Fisher-Tropsch process involves indirect liquefaction as the coal is first gasified to produce a synthesis gas which is then catalytically converted to liquid products. The processes currently being developed are based on direct liquefaction and primarily involve: (1) solvent extraction (SRC process), (2) direct catalytic hydrogenation (H-Coal process) or (3) pyrolysis (COED process), as the mechanism for liquefaction. Following is a brief description of each of these processes.

Fischer-Tropsch:

At present, this is the only commercially available technology. First step in this process involves coal gasification with steam and oxygen in a Lurgi gasifier to obtain syngas. After purification (e.g. by Rectisol process) of the gas, fixed bed (Arge) or fluidized bed (Kellogg) process can be used to catalytically convert the syngas into liquid products. Both processes use catalysts that operate in the temperature range of 430 to 750^{o}F with gas pressures ranging between 250 to 400 psi. The liquefaction step is virtually the same as that employed in numerous commercial operations that start with partial oxidation of methane. A wide variety of products are produced by this process -- the major ones being gasoline, oils, paraffin waxes, and chemical products. As mentioned earlier this process has low conversion efficiency (40%) and can use only noncaking coal although the latter deficiency can be overcome by using an alternative gasifier such as the Koppers-Totzek unit.

Future technological improvements should result in better gas purification and catalytic liquefaction techniques leading to higher than current 40% efficiency. Gasification performance will improve as experience is gained with higher pressure Lurgi units. There is also some room for improvement in developing longer lasting, cheaper and at the same time, more tolerant to sulfur poisoning-type catalysts.

SRC Process:

The SRC process is presently developed to the pilot plant stage. This process involves refining of coal in a self-generated solvent (generated in the liquefaction process) in the presence of hydrogen. The liquid is filtered to remove organic material and ash, and fractionated to recover the solvent. This process is capable of using midwestern and eastern caking coals.

Raw coal is pulverized and mixed with a coal derived solvent to form slurry in a slurry mix tank. The resulting slurry is mixed with hydrogen, produced in other steps of the process, and is pumped through a fired preheater on the way to being passed into a dissolver where about 90% of the moisture and ash-free coal is dissolved. Also in the dissolver, the coal is depolymerized and hydrogenated resulting in an overall reduction in product molecular weight, and the solvent is hydrocracked to form lower-molecular weight hydrocarbons that range from light oil to methane. From the dissolver, the mixture is passed through a high pressure flash vessel, operating at 625°F and 995 psig, to separate the gases from the slurry of undissolved solids and coal solution. The raw gas is sent to a hydrogen recovery and gas desulfurization unit. The hydrogen recovered is recycled with the slurry coming from the slurry mix tank. The slurry from the flash vessel goes to a rotary filter where the undissolved coal solids are removed. In the commercial-scale process, the solids can be sent to a gasifier-converter where on being reacted with supplemental coal, steam, and oxygen, they produce hydrogen for use in the process. The solids-free coal solution from the filter goes to the solvent recovery area where the solvent for recycle is removed by vacuum flash distillation. The bottom fraction (SRC) is a hot liquid with a solidification point of at least 300°F. The liquid product can be transported hot as a liquid fuel or allowed to cool, solidify and produce relatively clean solid fuel.

Based on pilot plant operations, it is found that coal conversion rates generally range from 85 to 95%, and yields of solid SRC product from 50 to 70% of the moisture and ash-free coal charge. Sulfur in the SRC product is 0.6-0.9%, depending on operating conditions and coal type, and ash content is 0.6-0.16%. The SRC product is brittle and has a gross heating value of about 16,000 Btu/lb regardless of coal type.

H-Coal Process:

This is the only advanced technology that offers two modes of operation whereby either an environmentally acceptable fuel oil production is maximized or a liquid feedstock acceptable to a petrochemical refinery is produced as a chief product. This process involves the direct hydrogenation of coal in the presence of a catalyst under three-phase, ebullient bed conditions. The H-Coal process is effective with all types of coal and would be particularly usefuel on highly volatile eastern coals with high sulfur.

In the actual process coal is dried to 150-200°F, pulverized to minus 60 mesh, slurried with coal derived solvent oil, and pumped to a pressure of about 200 atm. The slurry is mixed with compressed hydrogen and fed to the preheater and ebulliated bed reactor, which is typically at 3000 psig and 850°F. The heart of the process is the ebulliated bed reactor containing catalyst. The bed is kept ebulliated by internally recycled oil.

In the reactor the coal is catalytically hydrogenated as the dissolution occurs. The vapor product leaving the top of the reactor is cooled to separate the heavier components as a liquid. Light hydrocarbons, ammonia, and hydrogen sulfide are absorbed from the gas stream and the remaining hydrogen-rich gas is recycled. The liquid from the condenser is fed to an atmospheric distillation unit. The liquid-solid product from the reactor, containing unconverted coal, ash, and oil is fed into a flash separator. The material that boils off is passed to the atmospheric distillation unit that yields light and heavy distillate products. The bottom product from the flash separator (solids and heavy il) is further processed in hydroclone and filtration units to remove solid residue. The filtrate is stripped and fractionated further. Heavy distillate is recycled as a slurry medium.

The composition of the end product for a given coal type is determined by the operating conditions in the reactor. High pressure, high temperature and high coal residence are required in the reactor to produce syncrude as the major product. On the other hand, pressure, temperature and residence time must be low if residual fuel oil is the desired product.

Expected areas of improvements in the application of this technology include higher solid/liquid separation efficiency, longer catalyst life, higher coal throughout and decrease in consumption of hydrogen.

Coal conversion rates in this process range from 90 to 95% of moisture and ash-free coal. The overall thermal efficiency of coal to syncrude conversion in a commercial sized plant is expected to be in the 65-70% range.

COED Process:

This process involves pyrolysis of coal to produce synthetic crude oil, gas and char. The gas can be used as a fuel or processed further for conversion to hydrogen. The char can also be burned as a fuel, or with the application of additional technology, gasified. Use of high-sulfur, agglomerating eastern coals for conversion has been demonstrated in the pilot plant based on this technology. Pyrolysis involves stripping liquids from coal without going to high pressures and is not primarily aimed at removing sulfur. It leaves a large amount of char with a sulfur content equivalent to that in the feed coal. The products of pyrolysis are treated in a second step to remove sulfur.

The COED process is based on the multistage, fluidized-bed pyrolysis of coal. The coal is crushed, partially dried, and then fed to a series of four fluidized-bed pyrolyzers. Each pyrolyzer is operated at a successively higher temperature maintained just below the point at which the coal would agglomerate. The staging temperatures and the number of stages actually required depend on the agglomerating properties of the coal. Heat for the process is generated by burning a portion of the char in the last pyrolizer and then flowing the off-gases countercurrently to the forward char flow.

Pyrolysis product gas, containing the volatile matter released from the coal in the pyrolyzers, passes into a cyclone which removes the fines. The vapors leaving the cyclone are then quenched directly with water in a scrubber to condense the oil, and the gases and oils are separated in a decanter. The oil from the decanter is dehydrated and filtered. The solids-free oil is then pressurized and mixed with hydrogen in a fixed-bed catalytic reactor to remove nitrogen, sulfur and oxygen. The gas and char can also be desulfurized and converted to the desired form or composition.

Production cost estimates and resource requirements for implementation of syncrude production scenarios for the years 1985 and 2000 will be discussed later in this appendix.

d. Hydrogen:

The principal uses of industrial hydrogen are in petroleum refining and for production of ammonia, methanol, and other organic chemicals. Because of its clean burning characteristics, additional demands for hydrogen as a natural gas supplement, electric utility fuel for peak shaving applications, air transport fuel and as a special purpose vehicle fuel in limited urban transportation applications may materialize between 1985 and 2000. Presently, essentially all hydrogen is produced by the catalytic reforming of natural gas in the presence of steam. Substantial quantities of hydrocarbon feed stock are used in producing this industrial hydrogen. By 1980 feed stock requirements are projected to be equivalent to 0.7 million B/D of crude oil and this will increase to 1.6 million B/D by the year 2000 (considering only the present day uses of hydrogen) if alternative feed stocks are not used. Reduction of the consumption of natural gas and/or light hydrocarbon feed stocks for the production of industrial hydrogen can best be achieved during the 1980-2000 period by using coal as an alternative feed stock.

Hydrogen can be produced from coal by using processes basically similar to the ones discussed under coal conversion to subsitute natural gas (SNG). When hydrogen is the desired product, coal is gasified at a higher temperature compared to that required for SNG production. A lower overall thermal efficiency occurs in the hydrogen operation. The Koppers-Totzek (K-T) process is currently used commercially to produce hydrogen from coal in foreign countries. In the K-T process, finely ground coal is gasified at about 2700°F and atmospheric pressure to produce synthesis gas, a mixture of H_2, CO, CO_2, H_2O, H_2S, and SO_2. The sulfur-containing components are removed, and the remaining gases are compressed to about 300 psig and are then processed for CO shift conversion to H_2 and CO_2 removal. This process in its present form does not seem to be economically attractive for U.S. operations. As in the case of coal-syngas conversion, the investment and operating costs for K-T gasification could be reduced by operating the gasifier at 450 psig. This would reduce the physical size of the gasifier vessels, would reduce the costs of gas compression, and would reduce the size of the gas processing facilities downstream of the reactor. Pressurized operation of the gasifier would, however, require facilities for forcing the pulverized coal feed into the 450 psig gasifier vessel and removing the ash from this vessel. These areas presently are subjects of extensive study in coal gasificiation pilot plants.

Another process being developed by IGT, DOE, and AGA for the production of hydrogen from coal is the steam-iron process. The steam-iron process is a relatively complex system for producing hydrogen. In this process, three major vessels are used: producer, reducer, and oxidizer. Char is fed into the producer vessel where it reacts with air and steam to generate hot reducing gas. A temperature of 2000°F in the producer permits generation of a good reducing gas containing four times as much hydrogen and carbon monoxide as water and carbon dioxide. Hot producer gas enters the reducer and is mixed with a recirculating stream of iron oxide solids. In this reducing stage, oxygen is removed from the iron oxide solids to produce metallic iron. These reduced iron solids are fed to the oxidizer and are mixed with steam. The iron is oxidized to its oxide, and a hydrogen-steam mixture is produced. The advantages of this system include elimination of the need for a large oxygen or power plant and reduction in the amount of carbon dioxide scrubbing. These may compensate for the additional costs of the high-pressure steam-iron reactor. At the present time, however, the pressurized coal gasification process appears to provide attractive economic advantages for industrial hydrogen manufacture.

e. Methanol:

Methanol is a light liquid presently manufactured in significant quantities for use in chemical applications. Methanol is a clean-burning fuel that can be readily transported by pipeline, truck, rail, or barge. Potential applications where methanol can replace oil and natural gas include electrical power generation, industrial fuels, motor vehicle transportation, and industrial feed stock applications.

Essentially all methanol manufactured in the U.S. (about 3.8 million ST/year) is produced by steam reforming of light hydrocarbons. However, one large plant recently announced for the Houston area will employ resid partial oxidation. Future shortages of light hydrocarbon feed stocks suitable for steam reforming will encourage the consideration of resid and coal as alternative feed stocks.

The technology for producing methanol from coal is well established, and there are several commercial-scale plants in operation outside of the United States. As with coal gasification, there are basically three proven gasification design concepts: fixed, fluidized, and entrained beds. All of these methods can be used to gasify coal using steam and oxygen to produce synthesis gas. From a process standpoint the pressure and the bed type in-influence the composition of the synthesis gas produced. The correct ratio of hydrogen to carbon monoxide (2:1) with limited other ingredients is desired for methanol synthesis. The following reaction takes place between hydrogen and carbon monoxide at 750-1500 psi and at 400-600^{o}F over a catalyst.

$$2H_2 + CO \rightarrow CH_3OH$$

The ratio of H_2 to CO is below 2 in the synthesis gas produced by coal gasification. This can be adjusted by shifting a portion of raw synthesis gas, passing it through a catalytic shift converter where it reacts with steam to produce additional hydrogen and then combining it with the remaining portion of the synthesis gas.

The research being conducted in connection with coal gasification would also facilitate the design and construction of large scale commercial facilities utilizing coal to produce methanol in an economic and environmentally acceptable fashion in the 1980 - 2000 time period. The new technology, presently at pilot plant stage, will allow high-pressure gasification (thus reducing the investment cost), capability to operate on wider ranges of coal (specifically caking coals), and purification of raw gases at higher temperatures resulting in higher thermal efficiencies.

Synfuel Cost Comparison

The following capital and O&M costs refer to improved coal conversion technologies presently in the developmental stage. These technologies should become available for commercial use by the early 1980's. Because of the lack of experience with actual plants, there is some uncertainty associated with these cost data. Unit rate, in terms of thermal output, of all the plants considered here is approximately 250x10^9 Btu/day.

TABLE A-1

ESTIMATED SYNFUELS PRODUCTION COSTS*

Product	Unit Size	Investment Cost[1] 10^6 \$	Specific Capital Cost \$/10^6 Btu	Specific O&M Cost \$/10^6 Btu	Efficiency[1] of Coal Conversion	Prod. Cost (W/o Coal Cost) \$/10^6 Btu
1. Low Btu Gas	1.5×10^9 ft^3/day	675	1.27	.50	0.75	1.77
2. High Btu Gas	2.63×10^8 ft^3/day	940	1.77	.75	0.62	2.52
3. Syncrude	45,000 bbl/day	770	1.45	.65	0.67	2.10
4. Methanol	12,500 ton/day	1560	2.93	.85	0.65	3.78
5. Hydrogen	2.5×10^3 ton/day	760	1.43	.64	0.65	2.07

Assumptions: a. Stream factor = 90%
b. Annual fixed charge rate = 15.5%

*The costs are in 1974 dollars.

[1] Adopted from "Sourcebook for Energy Assessment", BNL 50483, December 1975.

II. SYNFUEL PRODUCTION CONSTRAINTS

Construction and operation of coal synfuel plants impose a steep demand on various resources. In this section, resources required to meet the implementation levels of synfuel production in the years 1985 and 2000, assumed in the model, are presented. Specifically, the following quantities were estimated for representative synfuel processes: plant investment, construction materials, equipment and manpower, and operating manpower and water requirements. Because of lack of strong correlation between the availability of the first three resources and regionalization, the data on investment, materials, and manpower are presented at an aggregated national level. On the other hand, in the case of water requirements, the data is disaggregated at the regional level. The question of availability of these resources is a difficult one and has been examined only in a broad sense; potential constraints, if any, are flagged. The availability of input coal requirements at the regional level, not considered here, has been ensured by incorporating the regional supply constraints in the model.

Capital

Synthetic fuel production is a very capital intensive undertaking. A single project may typically cost in excess of $1 billion. Cost estimation of synfuel plants is a hazardous venture in view of the following uncertainties: (i) Commercial synfuel plants have never been constructed in the United States--some technologies are operating in other countries, but with outputs smaller than those considered commercial by U.S. standards, (ii) Construction costs, which traditionally have increased at a rate of 4 to 6 percent per year, soared nearly 30% in 1974. This also resulted in drastically reducing the economic viability of all synfuel projects.

Cumulative capital requirement estimates for the years 1985 and 2000 are shown in Table A-2. These requirements refer to the synfuel production scenarios discussed in Chapters III and IV. Annual capital requirement is dependent on actual construction schedule of these plants, and can be computed from this table.

TABLE A-2

Cumulative Synfuels Capital Requirements: 1975-2000

Facility	Unit Capital[1] Cost (1974 Dollars in Millions)	Unit Size (10^9 Btu/ day)	Cumulative Capital Requirement* (Billion Dollars) Year 1985	Year 2000 Business-As-Usual	Year 2000 Accelerated
1. High Btu Gas	940	250	5.72	22.88	45.76
2. Coal Liquids	770	250	.94	9.40	18.80
3. Low Btu Gas	675	250	4.12	12.36	24.72
Total			10.78	44.64	89.28

*Plant factor has been assumed to be 0.9.

Extremely large capital costs and unproven technologies have largely inhibited past commercialization efforts. Recent large increases in world energy prices have improved overall economics, but the possibility of unilateral lower world energy prices has added a new element of risk. In view of these uncertainties and risks, government incentives, in form of guaranteed loans, construction subsidy, tax credit, etc., seem likely if the desired production levels are to be achieved. These incentives will help the plant projects to get good credit ratings which is essential to attract massive amounts of capital required since the bulk of United States investment money flows only toward relatively low risk ventures.

1 Adopted from "Sourcebook for Energy Assessment," BNL 50483, December 1975.

Materials and Equipment

These requirements vary not only with respect to the process being used but also depend on location and coal characteristics. For example, plants constructed in water-rich areas have some advantage in that there is less need to provide for reuse of cooling water; as a result, extensive use of cooling towers is not generally required. Similarly, plants based upon lower heat value coals will require larger and more extensive materials handling equipment for processing the larger quantities of feed coal in order to maintain a given feed heat content. Table A-3 shows typical requirements of critical materials and equipment on the cumulative basis for the years 1985 and 2000.

Material and equipment requirements in a given year will depend on the construction schedule of the synfuel plants. The following constraints in connection with materials and equipment have been identified in the Project Independence report[1] for the time frame up to 1985.

(a) There is a serious shortage of steel for the fabrication of existing energy-related construction. Steel resources at present are being taxed to virtually their limit by existing demands. Although the cumulative demand of steel (≈400 thousand tons) for the construction of synfuel plants by 1985 is small compared with the approximately 150 million tons of raw steel being produced in the U.S. annually, the imposition of additionally requirements may necessitate the establishment of national priorities.

(b) The design parameters, i.e., diameter, length, operating pressure, and operating temperature, for some synfuel plants require the fabrication of reactor vessels which may be beyond the existing technology.

(c) Presently the large heavy-walled pressure vessels are fabricated at the shops and then transported to the construction

TABLE A-3

Materials and Equipment Requirements For Synfuels Production[1]: 1985-2000

Materials/ Equipment	Year 1985				Year 2000 Business-As-Usual				Year 2000 Accelerated			
	High Btu Gas	Coal Liquids	Low Btu Gas	Total	High Btu Gas	Coal Liquids	Low Btu Gas	Total	High Btu Gas	Coal Liquids	Low Btu Gas	Total
Steel												
Thick Plate (10^3 tons)	98	21.7	77	196.7	393	217	231	841	786	434	462	1,682
Structural (10^3 tons)	32	23	11.8	66.8	127	230	35.4	392.4	254	460	70.8	784.8
Reinforcing (10^3 tons)	9.8	4.6	2.8	17.2	39	46	8.3	93.3	78	92	16.6	186.6
Pipe (10^3 tons)	62	6.9	23.6	92.5	246	69	70.8	385.8	492	138	1,416	771.6
Total (10^3 tons)	201.8	56.2	115.2	373.2	805	562	345.5	1,712.5	1,610	1,124	691	3,425
High Pressure Vessels (quantity)	790	215	---	1,005	3,170	1,974	---	5,144	6,340	3,948	---	10,288
Compressors (quantity-over 750 HP)	60	30	---	90	245	296	---	541	490	592	---	1,082
Pumps (quantity)	700	180	375	1,255	2,805	1,810	1,125	5,740	5,610	3,620	2,250	11,480
Oxygen Plants (quantity at TPD)	18 @ 1200	3 @ 1200	---	21 @ 1200	73 @ 1200	26 @ 1200	---	99 @ 1200	146@ 1200	52@ 1200	---	198 @ 1200
Copper (10^3 tons)	2.1	NA	0.35	NA	8.5	NA	1.04	NA	17	NA	2.08	NA
Aluminum (10^3 tons)	26	NA	---	NA	102	NA	---	NA	204	NA	---	NA
Crushers/Grinders (quantity at 100 TPH)	36 @ 100	NA	---	NA	145 @ 100	NA	---	NA	290@ 100	NA	---	NA

TPD = Tons per day, TPH = Tons per hour; NA = Not available

[1] Based on unit material requirement data in FEA Project Independence Blueprint, "Synthetic Fuels from Coal", U.S. Department of Interior, November 1974.

site. Transportation restrictions on the movement of very large heavy-walled pressure vessels require field erection and fabrication of these vessels. The necessary field erection/fabrication technology is not proven for the vessels under consideration.

(d) Consideration will have to be given to the allocation of critical alloying elements, such as nickel, chromium, molybdenum, etc., to meet the needs of many of the vessel requirements for alloy and stainless steel. Copper and aluminum requirements are small compared to 1974 U.S. production of 1.6 and 4 million tons, respectively and should pose no problem.

Manpower

The manpower requirements include both operating and construction labor. These requirements are summarized in Table A-4. The construction manpower is presented on a cumulative basis while the operating labor corresponds to the requirement during the year denoted. These values are expected to be identical for all plants (±5%) regardless of location, year of construction, region or state. Clearly maximum requirement of construction manpower would occur around the mid-nineties and it is likely that some of the construction workers would remain to help operate the plants. Peak requirements for operating personnel will be reached in 2000.

In the case of the low synthetics production scenario, the manpower does not appear to be a constraining factor on a national basis, although pockets of shortages in some regions, e.g., Midwestern and Western coal regions, cannot be ruled out. However, availability of construction manpower in cases of accelerated synthetics production scenario in conjunction with expansion in other energy-related areas (refineries, electric utilities, etc.) might be expected to pose a substantial constraint.

TABLE A-4

Manpower Requirements[1] for Synfuels

Plant Construction and Operation (1975-2000)
(Units: 10^3 Man-Years)

Type of Manpower Requirements	Year 1985				Year 2000							
					Business-as-usual				Accelerated			
	High Btu Gas	Coal Liquids	Low Btu Gas	Total	High Btu Gas	Coal Liquids	Low Btu Gas	Total	High Btu Gas	Coal Liquids	Low Btu Gas	Total
Construction <u>(Cumulative Basis)</u>												
1. Construction Labor	13.7	2.1	3.2	1.9	54.9	21.3	9.7	85.9	110	42.6	19.5	172
2. Engineering Requirements	1.5	0.6	0.3	2.4	6.1	6.2	0.9	13.2	12.1	12.4	1.8	26.3
<u>Production (Current)</u>												
3. Operating Labor	0.9	0.2	0.3	1.4	3.4	1.7	0.9	6.0	6.8	3.4	1.8	12.0
4. Maintenance	2.6	0.4	0.8	3.8	10.4	3.9	2.5	16.8	20.8	7.8	5.0	33.6
5. Services Administration	1.1	0.1	0.3	1.5	4.3	1.3	1.0	6.6	8.6	2.6	2.0	13.2

[1] Based on unit manpower requirement data cited in FEA Project Independence Blueprint, "Synthetic Fuels from Coal", U.S. Department of Interior, November 1974.

Water

Since there are no modern-design synfuel plants of commercial scale in the United States, estimates of water demand are based upon research operations, foreign experience, and design data for projected plants. In general synthetic plants are liberal users of water, both as a raw material in the process and as a process cooling and scrubbing fluid. Actual water requirements depend on a multitude of factors such as the kind of synthetic product being produced, process used, design parameters, and coal characteristics. On the average, water requirements for low Btu gas are less than those for high Btu gas because less hydrogen is needed and because the low Btu processes operate at higher temperatures resulting in greater heat-transfer efficiency. Coal liquefaction requires less water than gasification because in coal liquids the molar ratio of carbon-to-hydrogen is not changed much from coal itself. Design parameters such as type of cooling influence the water requirement, and the use of air cooling, rather than evaporative cooling, cuts down the total water requirement. The moisture content of coal also affects the total requirement. Due to its higher moisture content, western coal requires less water as some water can be recovered from the feed coal. Cooling water requirements in western plants can be expected to be approximately 50% less than eastern plant requirements because of greater use of air cooling and the recovery of water from feed coal in the west.

Unit water requirements[2,3] and regional water requirements are presented in Tables A-5 and A-6. A range of values is given in the case of unit water requirements because of variations discussed above, and average values are presented for total regional water requirements.

In order to ensure that the above water requirements do not violate the availability constraints, we have to estimate the quantity of water available on regional basis for synfuel production. There are some substantial problems associated with assigning water availability limits for a particular use. For example, synthetics processing requires large quantities of fresh water whereas power plants can use fresh water or saline water. There is no mechanism for differentiating among water qualities, and use of fresh water availability alone places an undue constraint on this estimate.

TABLE A-5

Unit Water Requirements for Synfuel Production

Product	Unit Water Requirement (Gallons/10^6 Btu output)	
	Range	Average
1. High Btu Gas	72 - 158	115
2. Coal Liquids	31 - 200	92
3. Low Btu Gas	67 - 153	110

There is also a real problem in estimating the future size of competing nonenergy uses--irrigation, industrial, drinking water, recreation, etc.--since these have many social determinants.

In order to try to get some perspective on the problem, use was made of a study of water needs conducted for the FEA's Project Independence Blueprint.(2) This report provides projections for 1985 of regional consumptive nonenergy use of fresh and saline water (combined) as well as values for total current water supply. The regional breakdown used in this report does not correspond with coal regions being used in our study, but combining these data with some from state sources allowed a reasonable disaggregation to be made. A number of sources suggest that a reasonable assumption to make is that roughly half the water available for energy use could be used for coal system activities. Thus, values for water availability constraints were calculated by taking half the difference between

TABLE A-6

Regional Water Requirements (10^9 gallons) for Synfuel Productions[1]

REGIONS	Year 1985				Year 2000							
					Business-As-Usual				Accelerated			
	High Btu Gas	Coal Liquids	Low Btu Gas	Total	High Btu Gas	Coal Liquids	Low Btu Gas	Total	High Btu Gas	Coal Liquids	Low Btu Gas	Total
Middle Atlantic	0.0	0.0	55.0	55.0	0.0	0.0	130.9	130.9	0.0	0.0	213.4	213.4
East North Central	0.0	0.0	0.0	0.0	0.0	0.0	34.1	34.1	0.0	0.0	82.5	82.5
North Appalachia	18.4	0.0	0.0	18.4	18.4	0.0	0.0	18.4	18.4	0.0	0.0	18.4
South Appalachia	1.15	0.0	0.0	1.15	1.15	0.0	0.0	1.15	1.15	0.0	0.0	1.15
Midwest	0.0	9.2	0.0	9.2	131.1	9.2	0.0	140.3	190.9	9.2	34.1	234.2
East North Great Plains	5.75	0.0	0.0	5.75	26.4	0.0	0.0	26.4	48.3	8.28	0.0	56.58
West North Great Plains	21.85	0.0	0.0	21.85	42.5	55.2	0.0	97.7	151.8	160.1	0.0	311.9
Rockies	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South West	10.35	0.0	0.0	10.35	10.4	27.6	0.0	38.0	49.4	6.44	0.0	55.84

[1]These water requirements correspond to synfuel plant locations as shown in Tables 11, 13, and 15.

total regional supply and the 1985 projected nonenergy demands. Clearly, these values are only a rough upper bound at best. In Table A-7, water supplies of only the western regions have been included as it is generally agreed there is abundant water for energy related activities in other parts of the country. It is to be noted that the water supply is to be shared by all coal energy activities such as coal mining, coal power plants, synfuel plants, etc. Because of the expected low level of synfuel production by the year 1985, water should pose no problem during this time period. Even in the year 2000, if the nonenergy use of water were to rise at historical growth rates (~2%) and thus cut into the water available for coal energy use, it seems quite likely that enough water would be available for synfuel conversion. One note of caution to be sounded here is that the regions considered in this study do not coincide with the water resource regions or basins and therefore, pockets of water shortage, requiring interbasin transfer of water, may remain undetected under the present regionalization scheme. Furthermore, the reason for the shortage problem in certain areas is legal rather than physical. Western states grant water rights according to a principle of allocation, rather than the alternate riparian system used in the east. Under allocation, a share of the water flowing in a stream can be granted to whomever needs it, whether that person holds adjacent property or not. The problem is especially acute in Colorado where water supplies have been exhausted in the legal, although not the physical sense.

TABLE A-7

Projected Western Water Supplies Available for Energy Use

(1985)

Region	Available Water for Energy Use in Year 1985 (10^9 gallons)
East North Great Plains	600
West North Great Plains	1,558
Rockies	277
South west	1,705

III. END USE TECHNOLOGIES

A. Fluidized Bed Combustion (FBC)

FBC provides a direct combustion process for coal with acceptable environmental impact and the potential for improved thermal conversion efficiency and reduced costs. Specifically, the FBC concept promises low levels of sulfur-dioxide and nitrogen-oxide emissions coupled with higher heat transfer rates resulting in higher power cycle efficiencies. In addition, FBC designs allow combustion of all grades of coal and pressurized FBC offers the benefits of reduced boiler size. FBC can be used in many energy sectors, such as electricity generation by utilities, industrial process heat, and steam generation by institutions for space heating.

Development of the fluidized bed has proceeded slowly until recently. In the 1960's and early 1970's, progress in developing the main concepts of FBC has been noteworthy both here and in the United Kingdom. Atmospheric FBC could be commercially available by early 1980. A test installation of a 30 MWe atmospheric-pressure unit, sponsored by DOE should go into operation in the very near future. Pressurized FBC, suitable for combined cycle operation for electricity generation, still has some unresolved technical problems, suggesting that there will be a lag in commercialization of such boilers as compared with atmospheric types. DOE is sponsoring a program with the aim of developing FBC capability for burning 1 quad of coal by 1985, and between 6 - 8 quads by the year 2000.

The FBC involves burning coal within a bed of granular, non-combustible material such as limestone or dolomite. The temperature of combustion typically ranges between 1400 and 1800^{o}F. The granular material can be injected into the combustor along with coal particles, crushed to a maximum size of ¼-½". The bed is supported by a distributor plate. Fluidization of the bed is achieved by driving combustion air up through the distributor plate, causing the granular bed particles to become suspended and act like a viscous boiling fluid. The heat generated in the bed is removed by a series of vertical or horizontal tubes holding heat transfer fluid. The bed solids transfer heat to the fluid more readily than does gas alone. Combustion efficiency of the FBC system is determined primarily by the elutriation of unburned carbon from the bed as the carbon loss in the bed and in the unburned gases is quite negligible. Carbon loss has been shown to decrease with temperature and increase with gas velocity. Typically, the combustion efficiency in one stage FBC is about 90% but can go as high as 98.5% with second stage combustion.

Atmospheric vs. Pressurized FBC

FBC can be designed for combustion to occur either at atmospheric pressure or at levels as high as 10 atmospheres. The former - and more developed - variant looks appropriate for both utility and industrial heating applications. The latter aims specifically at bigger, 200 MWe plus modular units, and can use combined cycle power generation. The pressurized FBC using combined cycle has higher overall efficiency [4] ($\sim$35%). However, pressurized FBC has the following problems to overcome before commercialization: (a) The effluent gas from combustion units contains small solid particles which tend to erode and corrode the gas turbine blades. This problem can be minimized by use of filters and cyclone stages, etc. (b) Because of high pressure operation, handling of coal, sorbent materials and solid wastes becomes difficult and requires a special handling system. (c) Regeneration of limestone from pressurized FBC proceeds at a slower rate than for atmospheric FBC system.

This may be due to the result of impervious layers of sulfates formed inside the limestone interstices because of greater pressure and temperature of hot gases.

Capital Cost

It is possible to burn about 10 times more fuel per unit volume in an FBC boiler than in a conventional one and 75% less heat transfer surface is needed, thus, allowing savings in vessel sizing. However, because of ancillary equipment such as the solid feed system and granular bed filters required for its operation, the overall dimensions of a pressurized FBC installation may not be as compact as may be suggested by boiler comparisons alone. Due to economies of shop rather than field fabrication, small boiler units can be fabricated in a factory more economically and then assembled at the site to construct a large system. In addition, FBC does away with the need for stack gas scrubbers because of insitu absorption of sulfur-dioxide. It is estimated that the combination of these factors permits a 10-20% capital cost reduction of FBC installation over conventional units. A breakdown of capital costs for a 600 MWe power plant using pressurized FBC and combined cycle operation is shown in Table A-8.

Environmental Effects

SO_x emission:

Use of SO_x - control sorbent (limestone/dolomite) as the bed material provides a means of removing sulfur oxides generated during combustion. In the actual process, limestone is calcined to calcium oxide which reacts with SO_2 and O_2 in the flue gas to form $CaSO_4$. The most important operating parameters which affect sulfur retention in FBC are temperature, Ca/S ratio and gas velocity. Experimental evidence suggests an optimum range[5] of 1400-1600°F for sulfur retention. Sulfur retention decreases as the gas velocity increases and Ca/S ratio decreases. At atmospheric pressure, SO_x removal [4] typically exceeds 90% via once-through use of limestone/dolomite and a Ca/S mole ration of 204:1. With such a removal rate, FBC can readily meet EPA's new source standard for large coal-fired boilers of 1.2 lb $SO_2/10^6$ Btu of coal.

NO_x emissions:

The low operating temperature (1400-1800^{o}F) of FBC holds down emissions of nitrogen oxides (NO_x). Well established relationships show that production of NO_x derived from combusion air rather than fuel nitrogen rises with temperature. Also, the presence of limestone helps to reduce NO_x formation derived from fuel nitrogen. As with SO_2, FBC units can meet EPA's new source emission ceiling of 0.7 lb. $NO_x/10^6$Btu of coal.

Particulates:

FBC does produce more particulates in the effluent gas than a conventional system since there is no slag to carry these off. However, the flyash size is course, easing collection and also lessening respiratory risks.

Data on typical pollutant releases have been included in Table A-8.

Sorbent Regeneration:

Approximately one ton of sorbent [6] (limestone/dolomite) is sulfated for the combustion of five tons of coal under the assumptions of typical Ca/S mole ration of 2, and 3% by weight sulfur content of coal. At this rate, large amounts of sulfated sorbent will be produced and must be disposed of in an economically/environmentally sound manner. Two options exist. First, the FBC may be operated with once-through sorbent, and with limestone/dolomite, both abundant and relatively cheap, the spent sorbent can be discarded. Calcium sulfate produced in the boiler may be in a

Table A-8

COSTS AND TECHNICAL PARAMETERS ASSOCIATED WITH FBC POWER PLANT

1. Plant Type: Pressurized Fluidized Boiler Combined Cycle Regenerative, Limestone-Dolomite System, 600 MWe
2. Capital Cost ($/KWe):

(i) Boiler Plant Equipment[a]	
Boiler	18.00
Related Equipment (Coal Handling & Feeding, Particulate Removal, Piping/Ducts, etc.)	48.00
Total	66.00
(ii) Two Step Limestone-Dolomite Regenerative System[b]	46.00
(iii) Other[c] (Turbines, Generators, Land, Structures, etc.)	164.00
SUBTOTAL	276.00
TOTAL (Including escalation, interest during construction, etc. ∿ 45%[c])	∿ 400

3. Energy Costs ($\$/10^6$Btu(e)):

Fixed Charges[d]	2.87
O&M Cost[e]	0.35
TOTAL (excluding coal cost)	3.22

For the sake of comparison, conventional coal-steam electric (excluding coal cost) costs $3.95\$/10^6$ Btu(e)

---

a. Adopted from reference 7, p. 25 and escalated to 1974 dollars. Escalation factor (1.27) was obtained by comparing our 1974 $ cost estimates with those of reference 7... (p. 10) for conventional coal-steam electric plant with scrubber.

b. Reference 8, p. 500.

c. Reference 7, p. 25.

d. Annual fired charge rate of 15% and plant factor equal to 70% has been used in computing this cost.

e. This cost is derived by escalating the value on p. VI-7 of reference 9 by 15% to convert 1972 dollars to 1974 dollars. This value includes cost of limestone at $5/ton. The regenerative system cuts down the requirement of limestone from 0.2 ton/ton of coal to .05 ton/ton of coal. Good agreement is found between this figure and the one given on p. 10 of reference 8 after escalation, if adjustment is made for regenerative limestone system in the latter figure.

TABLE A-8 (continued)

4. Efficiency:

Coal combustion efficiency = 0.90 - 0.98

Overall Coal-to-Electric efficiency -

Pressurized FBC [f] = 0.41

Atmospheric FBC [f] = 0.35

5. Emissions:

(i) Nitrogen Oxides [g]

Pressurized FBC -

NO_x ranges between 0.30 to 0.73 lb/10^6 Btu (e)

Atmospheric FBC -

NO_x ranges between 0.71 to 1.71 lb/10^6 Btu (e).

(ii) Sulfur Oxides [h]

It varies with sulfur content of coal.

High Sulfur Coal -

SO_x = 2.15 lbs/10^6 Btu (e)

Low Sulfur Coal -

SO_x = .35 lbs/10^6 Btu (e)

(iii) Particulates [i]

Particulate emission depends on sulfur content of coal.

High Sulfur Coal -

Particulates = 0.05 lbs/10^6 Btu(e)

Low Sulfur Coal -

Particulates = 0.04 lbs/10^6 Btu(e)

---

f. Reference 4, p. 69.

g. Reference 4, p. 70.

h. Derived from table on p. VI-7 of reference 9. Variation with respect to pressurized and atmospheric FBC is small. The value in the table corresponds to the larger of the two.

i. Derived from table on p. VI-7 of reference 9.

form suitable for disposal without further processing. EPA and DOE are sponsoring work on the possibility of using sorbent for fertilizer. Alternatively, the spent sorbent may be regenerated and recycled to the desulfurizer. The process uses a fluidized-bed reaction vessel in which sulfated sorbent is reacted with a H_2/CO reducing gas to produce CaO and $CaCO_3$. The stream of SO_2 and H_2S produced in the process is sent to the sulfur recovery plant. The regenerated sorbent is returned to FBC with the required amount of fresh sorbent to supplement the regenerated sorbents' reduced activity and sorbent losses. This reduces the sorbent requirement of from 20% to 5% of the coal to achieve the same sulfur removal as a once-through system. The capital cost of a two-step regenerative system has been included in the power plant cost considered in Table A-8.

B. Fuel Cells

The fuel cell offers the potential of highly efficient, virtually pollution-free and quiet electricity generation regardless of the plant size. It can operate on any of a variety of fuels derived from coal, e.g., synthesis gas, hydrogen, SNG, syncrude and methanol.

In the fuel cell energy conversion process, a hydrogen rich fuel is electrochemically combined directly with oxygen from the air to produce electricity and water. Waste heat produced by the reaction is removed with the exhausted air. Commercial fuel cell power plants will generally have three main components: fuel reformer, fuel cell section, and the inverter. The reformer converts the synthetic fuels into a more reactive form, normally a gaseous mixture of hydrogen with some carbon dioxide. Use of synthesis gas or impure hydrogen with the current fuel cell technology, i.e. acid fuel cells, does not need a fuel reformer. The reformer is based on processes which are commercially developed and are in general use by the chemical industry. The fuel cells of the future, e.g. molten carbonate and solid oxide types, etc., which would allow operation on most of the coal derived fuels, could either eliminate the reformer altogether or allow simplification of the fuel reformer. The fuel cell section consists of a number of individual cells which promote the elctrochemical combination of the processed fuel with oxygen from the air to produce direct current (d.c.) electricity at $\approx$0.78 volts each. In a fuel cell stack, a number of such cells are connected electrically in series to permit generation at hundreds or thousands of volts (d.c.). Connecting a number of cell stack assemblies in parallel permits generation of any power level from kilowatts to multi-megawatts. The inverter converts d.c. from the cell section into a.c. suitable for commercial applications. State-of-the-art inverters are nearly 96% efficient in converting large amounts of d.c. power to a.c. The development of inverters for fuel cell plants has been directed toward reduction in unit cost and size.

Characteristics of Fuel Cell Systems

A fuel cell is a direct conversion device, converting chemical energy directly into electricity through an electrochemical process. The direct energy conversion process in the fuel cell is capable of much higher theoretical efficiency than a heat engine because it is not limited by the Carnot cycle. Moreover, fuel cell systems need not be big to be efficient because single fuel cells can be assembled in stacks of varying sizes to produce a wide range of output levels. This factor also accounts for high efficiencies both at full as well as partial loads. Because the fuel reacts electrochemically, rather than by burning in air, there are no environmentally unacceptable emissions of NO_x or unburned and partly burned gaseous and particulate products. In addition, the only moving parts in fuel batteries are fuel pumps and, perhaps, electrolyte pumps, so the operation is inherently very quiet. There is relatively little thermal pollution, because less energy is lost as heat. The nature of the fuel cell process and the system operating temperature levels permit the power plant waste heat to be rejected to ambient air or be recovered for use in a variety of thermal energy applications including industrial process or space heating. No external source of water is required for cooling of the conversion process. Another advantage of a fuel cell system lies in modular construction that permits factory assembly and checkout, resulting in vastly reduced installation lead times.

Applications:

The uses to which fuel cells may most profitably be applied are the elctric power generation and transportations sectors.

Electric generation via fuel cells provides utilities with new options for meeting both the growing energy demands and the increasing conservation and environmental constraints that their systems must meet. These expanded options, stemming from the characteristics of the fuel cells, are discussed below:

Dispersed Generation:

Efficiency of fuel cell systems is independent of the unit size. This characteristic coupled with low exhaust emissions and low noise levels permits fuel cell systems to be sited almost anywhere from a central station to the basement of an individual home. Since the power plant does not require an external water supply for cooling or energy processing, siting is not limited by water availability or cooling water thermal restrictions.

Load Following:

The modular nature of the fuel cell system provides the flexibility for adding power in small blocks at the time and point in the system where it is needed. This results in generation capacity which can closely follow the demand curve for electric power at a nearly constant heat rate.

Waste Heat Recovery:

Because fuel cell powerplants can be located close to the load, the recovered waste heat can be easily put to practical use in applications such as industrial process heat, absorption air conditioning and space or water heating.

Economic Energy Production:

Based on estimates of capital and O&M costs for fuel cells, the energy conversion costs ($/kWh) have been shown in Table A-9. These figures show cost savings in comparison with conventional electric generation systems. In applications where the fuel cell's waste heat can be utilized, additional savings can be made possible. Siting of fuel cell systems close to demand centers can provide further savings due to reduction in transmission and distribution costs.

Emissions Reduction:

Fuel cell systems release vastly reduced emissions relative to the conventional systems. Emissions,* based on tests on experimental fuel cells are:

Emission Type	Amount (lbs/10^6 Btu (e))
NO_x	0.032 - 0.045
SO_2	0.000057
Particulates	0.0000072
Smoke	Negligible

In the transportation sector, the same virtues of efficiency and low pollution make the fuel cell attractive but the additional major requirement of large power/weight ratio (power density) must be met. With present technology, this is difficult to meet for small personal vehicles. However, because of less stringent power density requirements for large buses, trucks, trains, and ships, fuel cell systems of adequate performance can probably be built with existing technology, at least as far as cells themselves are concerned. The detailed engineering analysis necessary to actually build the powerplant and to ensure reliability and control is

*Taken from Reference 10 and converted to units based on output electric energy by using system efficiency∼40%

Table A-9

Developmental Status and Cost Estimates
for Various Fuel Cell Technologies

Primary Fuel Conversion in Central Facility	Secondary Fuel Conversion in Processor	Power Generation System Type	Fuel Cell Type	Fuel Cell Technology Status	Probable Commercialization Data[a]	Capital Costs ($/kW)		Total	Heat Rate[d] (Btu/kWh)	Power Generation Cost[e] (mills/kWh)
						Fuel Cell[b]	Processor[c]			
Coal - syngas	None	Central	Molten Carbonate	Second Generation	1985	140	-	140	8,200	3.92
	None	Central	Acidic	First Generation	1980	170	-	170	7,750	4.49
Coal-H_2	None	Central	Alkaline	Second Generation	1985-1990	140	-	140	6,500	3.92
Coal - methanol	Methanol - impure H_2 (catalytic conversion)	Dispersed & Peak - Shaving	Acidic	First Generation	1980	170	50	220	7,750	6.37
	Methanol - H_2 (partial oxidation)	Dispersed & Peak-Shaving	Alkaline	Second Generation	1985-1990	140	60	200	6,500	6.00
Coal - SNG	SNG - impure H_2 (reforming)	Dispersed	Acidic	First Generation	1980	170	55	225	7,750	6.47
	In-situ methane reforming with fuel cell	Dispersed	Molten Carbonate	Second Generation	1985	140	-	140	7,500	4.87
Coal	Fuel Cell incorporated in coal gasifier	Central	Solid[f] Oxide	Third Generation	1990	140	-	140	5,750	3.92

FOOTNOTES FOR TABLE A-9

a. Estimates based on references 11 and 12.

b. The fuel cell costs include cost of inverter for conversion of d.c. to a.c. These costs, with the exception of alkaline fuel cells, are based on estimates as reported in Table 4-13 of ref. 13.

c. The costs of fuel processors, used for secondary fuel conversion to fuel cell fuel, refer to second generation technology and are extracted from Table 4-12, of ref. 13.

d. These are unintegrated heat rates, i.e., they are based on fuel to fuel cells. Integrated heat rates are based on raw or primary fuel. These figures are adopted from Tables 4-5 and 4-11 of ref. 13.

e. Annual fixed charge rate of 15% and plant factors of 8000 hrs/year (under the assumption of base load system) have been used in computing these costs. Also, O&M costs equal to 1.30 and 2.25 mills/kWh (from p. 39 of ref. 10) have been included for central and dispersed generating systems respectively. It is to be noted that these costs refer to conversion of secondary fuel to electricity, i.e., primary fuel and their conversion costs are not included.

f. Reference 12.

g. All the costs are in 1974 dollars. An inflator of 5%/year has been used for this conversion.

another matter. Also, detailed economic analysis has yet to be performed to prove the economic viability of such a system.

C. Use of Coal Derived Fuels

Use of coal as a primary fuel for fuel cells seems to be an attractive option because of the significant opportunity that it presents for integration with a coal gasifier in central power plants. The exhaust heat of a fuel cell can be used for coal gasification to achieve high overall (coal to a.c. power) system efficiency (~ 45%* with second generation technology). Although various coal derived fuels can be used in fuel cells, the economics of using these fuels varies because of costs associated with conversion transportation and storage. With the present fuel cell technology (acid electrolyte), production of synthesis gas from coal provides the best alternative for centralized electric generation. Such a system does away with the need of a fuel reformer as the synthetic gas can be used directly in the fuel cell. However, second generation fuel cells can alter the economics in favor of other fuels. For example, alkaline fuel cells offer the potential of high efficiency, low cost and high power density, but can only be used with pure hydrogen as the fuel. Likewise, in situ SNG reforming with a molten carbonate cell could offer the advantage of cost reduction. Third generation technology involves the development of a high temperature solid oxide fuel cell, which has the potential of being incorporated directly in the coal gasifier resulting in much higher efficiency and significant cost reduction. Because of the gaseous form and rich hydrogen content of fuels used by fuel cells, products of coal liquefaction would require considerable downstream processing to be upgraded to fuel cell quality. This puts coal liquefaction at a substantial disadvantage

*p. 3 of Reference 13

compared to coal gasification, and, therefore, does not seem to be a viable alternative. Even though it is a liquid and involves higher cost to produce from coal, methanol, obtained via the gasification route, has been included as one of the fuel options for dispersed electric generation because of its ease of reforming for fuel cell uses and economic storage and transportation characteristics. Costs and heat rates corresponding to attractive coal derived fuel - fuel cell combinations are shown in Table A-9.

The first generation fuel cell technology is close to meeting the life, heat rate, and cost requirements to compete as a utility generator. Nevertheless, as with all advanced technology concepts, the fuel cell is presently a high risk venture and is not expected to become a commercial reality until 1980. Furthermore, second and third generation technology will extend into the mid to late 80's and early 90's respectively. With advanced coal gasification also coming into practice at about the same time, fuel cells appear to provide an attractive long term energy option because of their basic compatibility with coal derived fuels.

References for Appendix A

1. FEA Project Independence Blueprint, "Synthetic Fuels from Coal", U.S. Department of Interior, November 1974.

2. FEA Project Independence Blueprint, "Water Requirements, Availabilities, Constraints, and Recommended Federal Actions", Water Resources Council, November 1974.

3. Davis, John, "Western Water Supply OK", Chemical Energy, May 12, 1975.

4. News Feature in Chemical Engineering M 69-71, June 7, 1976.

5. Nack, H., etal, "Fluidization - Bed Combustion Review", p. 360 in Fluidization Technology, Vol. II, 1976, Keairns, Dale L., editor, Hemisphere Publishing Corp.

6. Shore, F. J., "Characteristics of New Energy Technologies - Fluidized Bed Combustion of Coal", BNL 21915, IEA Energy Systems Analysis, Brookhaven National Laboratory, Upton, N.Y. 11973.

7. "Evaluation of the Fluidized-Bed Combustion Process", Vol. I, EPA 650/2-73-048a, Westinghouse Research Laboratories, Pittsburgh, Pa. 15235.

8. Proceedings of the Fourth International Conference on Fluidized Bed Combustion, December 9-11, 1975, sponsored by ERDA and Mitre Corp., published May 1976 by Mitre Corp., McLean, Virginia 22101.

9. "Environmental Impacts, Efficiency and Cost of Energy Supply and End Use", H 17-593, January 1975, Hittman Associates, Inc., Columbia, Maryland.

10. "National Benefits Associated With Commercial Application of Fuel Cell Power Plants", ERDA 76-54, February 27, 1976, United Technologies Corporation.

11. Fickett, Arnold P., "An Electric Utility-Fuel Cell: Dream or Reality?", EPRI-103, Electric Power Research Institute, Palo Alto, California.

12. Lawrence, L. R., Jr., "Fuel Cells Offer Flexibility and More Efficiency", p. 24 in Public Power, May-June 1976.

13. "Assessment of Fuels for Power Generation by Electric Utility Fuel Cells", PB-247 216, October 1975, Arthur D. Little, Inc.

14. Ackerman, John P., "Status and Outlook for Energy Conversion Via Fuel Cells", Conf. 740462-1, Argonne National Laboratory, Argonne, Illinois.

APPENDIX B

SUPPORTING COMPUTATIONS

TABLE B-1

1985 Utility Coal Transport Costs*
\$/Ton (¢/10^6 Btu)

Supply \ Demand	New England	Mid Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	8.28	6.02	8.78	6.32[1]	4.52[1]	11.76	12.24		
	(34)	(24)	(36)	(26)	(18)	(48)	(50)		
South Appalachia	9.74[6]	7.40	7.02	5.52[1]	4.13[1]	10.22[2]	11.20[3]		
	(39)	(30)	(28)	(22)	(17)	(41)	(45)		
Midwest	12.72	10.93	8.56	4.55	6.30	7.02	9.77		
	(58)	(50)	(39)	(21)	(29)	(32)	(44)		
Gulf	8.50[4]	7.48[4]	4.12[4]	5.85[1]	6.44[1]	11.20	5.49		
	(61)	(53)	(29)	(42)	(46)	(80)	(39)		
East North Great Plain	17.64	16.42	13.93	10.62	9.93[5]	7.87	12.99	10.93	
	(126)	(117)	(100)	(76)	(71)	(56)	(93)	(78)	
West North Great Plain	21.32	19.60	16.17	12.72	14.28	8.84	11.93	6.02	12.99
	(120)	(110)	(91)	(71)	(80)	(50)	(67)	(34)	(73)
Rocky Mountain	21.94	20.89[4]	17.15[4]	14.28	15.25	10.62	11.93	3.83	12.42
	(84)	(80)	(71)	(60)	(64)	(44)	(50)	(16)	(52)
Southwest	20.99[4]	19.97[4]	17.15[4]	15.00	15.35	11.66	10.93	8.05	12.72
	(118)	(112)	(96)	(84)	(86)	(66)	(61)	(45)	(71)

* All shipments are unit rail, except as noted.
Regional demand centroids are indicated in Figure 5.
Adopted from Ref. 11.

(1) River shipment

(2) Barge to St. Louis, unit rail to Omaha

(3) Barge to Vicksburg, Miss., unit rail to Dallas

(4) Unit rail (as needed) to Houston, Deepwater Collier, Unit rail (as needed) to centroid.

(5) Unit rail to St. Louis, barge to

(6) Unit rail to Hampton Boads, Coastal Collier to Boston.

TABLE B-2

2000 Utility Coal Transport Costs*
$/Ton (¢/$10^6$ Btu)

Demand / Supply	New England	Mid Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	11.18 (46)	8.13 (32)	11.85 (49)	8.53[1] (35)	6.10[1] (24)	15.88 (65)	16.52 (68)		
South Appalachia	13.15[2] (53)	9.99 (41)	9.48 (38)	7.45[1] (30)	5.58[1] (23)	13.80[3] (55)	15.12[4] (61)		
Midwest	17.17 (78)	14.76 (68)	11.56 (53)	6.14 (28)	8.51 (39)	9.48 (43)	13.19 (59)		
Gulf	11.48[5] (82)	10.10[5] (72)	5.56[5] (39)	7.90[1] (57)	8.69[1] (62)	15.12 (108)	7.41 (53)		
East North Great Plain	23.81 (170)	22.17 (158)	18.81 (135)	14.34 (103)	13.41[6] (96)	10.62 (76)	17.54 (126)	14.76 (105)	
West North Great Plain	28.78 (161)	26.46 (148)	21.83 (122)	17.17 (97)	19.28 (106)	11.93 (68)	16.11 (90)	8.13 (46)	17.54 (98)
Rocky Mountain	29.58 (113)	28.20[5] (108)	23.15[5] (96)	19.28 (79)	20.59 (84)	14.34 (59)	16.11 (67)	5.17 (28)	16.77 (69)
Southwest	28.34[5] (159)	26.96[5] (151)	23.15[5] (130)	20.25 (111)	20.72 (115)	15.74 (88)	14.76 (83)	10.87 (58)	17.17 (97)

* All shipments are unit rail, except as noted.
Regional demand centroids are indicated in Figure 5. Adopted from Ref. 11.

(1) River Shipment
(2) Unit rail to Hampton Roads, Coastal Collier to Boston.
(3) Barge to St. Louis, unit rail to Omaha
(4) Barge to Vicksburg, Miss., unit rail to Dallas
(5) Unit rail (as needed) to Houston, Deepwater Collier, Unit rail (as needed) to centroid.
(6) Unit rail to St. Louis, barge to destination.

TABLE B-3

1985 Industrial Coal Transport Costs*

$/Ton (¢/$10^6$ Btu)

Demand / Supply	New England	Mid Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	9.84 (40)	7.67 (31)	10.34 (42)	9.00 (37)	10.06 (41)	13.44 (55)	15.08 (61)		
South Appalachia	11.52 (46)	9.00 (36)	8.46 (34)	8.46 (34)	7.67 (31)	12.73 (51)	13.75 (55)		
Midwest	14.40 (65)	12.73 (58)	10.06 (46)	5.76 (26)	7.54 (34)	8.46 (38)	11.32 (51)		
Gulf	21.45 (98)	16.50 (75)	12.16 (55)	14.15 (64)	11.99 (55)	13.10 (60)	6.72 (31)		
East North Great Plain	19.80 (141)	18.43 (132)	16.78 (120)	12.42 (89)	14.75 (105)	9.41 (67)	14.58 (104)	12.73 (91)	
West North great Plain	23.93 (134)	22.00 (124)	18.15 (102)	14.40 (81)	15.82 (89)	10.53 (59)	13.55 (76)	7.67 (43)	14.57 (82)
Rocky Mountain	26.95 (112)	24.48 (102)	19.25 (80)	15.82 (66)	16.78 (70)	12.42 (52)	13.55 (56)	6.06 (25)	14.08 (58)
Southwest	28.33 (159)	25.50 (143)	19.25 (108)	16.50 (93)	17.05 (96)	13.44 (76)	12.73 (72)	9.60 (54)	14.40 (81)

* All shipments are assumed to be spot rail.
Regional demand centroids are indicated in Figure 5.
Adopted from Ref. 11.

TABLE B-4

2000 Industrial Coal Transport Costs*

$/Ton (¢/$10^6$ Btu)

Demand / Supply	New England	Mid Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
North Appalachia	14.25 (58)	11.11 (45)	14.98 (61)	13.03 (54)	14.57 (59)	19.47 (80)	21.84 (88)		
South Appalachia	16.68 (67)	13.03 (52)	12.25 (49)	12.25 (49)	11.11 (45)	18.44 (74)	19.91 (80)		
Midwest	20.86 (94)	18.44 (84)	14.57 (67)	8.34 (38)	10.92 (49)	12.25 (55)	16.39 (74)		
Gulf	31.07 (142)	23.90 (109)	17.61 (80)	20.49 (93)	17.37 (79)	18.97 (87)	9.73 (45)		
East North GreatPlain	28.68 (204)	26.69 (191)	24.30 (174)	17.99 (129)	21.36 (152)	13.63 (97)	21.12 (151)	18.44 (132)	
West North great Plain	34.66 (194)	31.86 (180)	26.29 (148)	20.86 (117)	22.91 (129)	15.25 (85)	19.62 (110)	11.11 (62)	21.10 (119)
Rocky Mountain	39.03 (162)	35.45 (148)	27.88 (116)	22.91 (96)	24.30 (101)	17.99 (75)	19.62 (81)	8.78 (36)	20.39 (84)
Southwest	41.03 (230)	36.93 (207)	27.88 (156)	23.90 (135)	24.69 (139)	19.47 (110)	18.44 (104)	13.90 (78)	20.86 (117)

* All shipments are assumed to be spot rail.
Regional demand centroids are indicated in Figure 5.
Adopted from Ref. 11.

Table B-5

Costs of Gas Transportation*
¢/10^6 Btu
(1975 $)

Supply \ Demand	Year	New England	Mid Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
NATURAL GAS										
East South Central	1985	26	14			0				
	2000	28	15			0				
West North Central	1985				20		10		14	
	2000				22		11		15	
West South Central	1985	54	43	17	28	27	15	0	32	55
	2000	58	47	18	30	29	16		35	60
Rocky Mountain	1985						17		12	32
	2000						18		13	35
SUBSTITUTE NATURAL GAS										
North Appalachia	1985	20	11							
	2000	21	12							
South Appalachia	1985	26	16		20	16				
	2000	28	17		21	17				
Midwest	1985				7					
	2000				8					
Gulf	1985	54	43	17	28	27	15	0		
	2000	58	47	18	30	29	16	0		
East North Great Plains	1985				48		28		45	83
	2000				68 (1)		40 (1)		64 (1)	118 (1)
West North Great Plains	1985				44		22 (3)		17	59
	2000				57 (2)		31		24 (3)	85 (1)
Rocky Mountain	1985				57		47		20	65
	2000				74 (2)		63 (2)		29 (1)	92 (1)
Southwest	1985								29	34
	2000								42 (1)	36

*Shipments use existing networks except as noted.
(1) All new 18" pipe.
(2) New 18" pipe connecting to existing network.
(3) All new 36" pipe.

Table B-6

Costs of Oil Transportation
(1975 \$; ¢/10^6 Btu)

	Year	New England	Mid Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific
CRUDE PRODUCTION										
West South Central	1985	12	10	4	6	6	3		7	12
	2000	14	11	4	7	7	3		8	14
Pacific	1985							12	13 (1)	
	2000							14	17 (1)	
SYNCRUDE										
North Appalachia	1985	4	2							
	2000	5	3							
South Appalachia	1985	6	3		3	2				
	2000	6	4		3	3				
Midwest	1985				2					
	2000				2					
Gulf	1985	12	10	11		6				
	2000	14	11	4		7				
East North Great Plains	1985				13 (1)		9 (1)			
	2000				19 (1)		13 (1)		21 (1)	
West North Great Plains	1985				14 (1)		12 (1)		6 (1)	
	2000				14 (3)		17 (1)		5 (1)	
Rocky Mountain	1985				13 (2)		8 (2)		5	
	2000				18 (2)		11 (2)		7	
Southwest	1985								9 (1)	9
	2000								13 (1)	10

(1) New 9" pipeline.
(2) New 9" pipeline connecting to existing system.
(3) New 18" pipeline connecting to existing system.
(4) All new 36" pipeline.

Table B-7

1985 Utility Coal Costs
(1975 ¢/10^6 Btu Delivered)

Demand Regions

Supply Region	Sulfur Content	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supplies (10^{12} Btu)
North Appalachia	Low	135	125	137	127	119	149	155			374
	High*	136	126	138	128	120	150	156			3618
South Appalachia	Low	137	128	126	120	115	139	143			3890
	High*	141	132	130	124	119	143	147			1589
Midwest	Low	157	154	143	125	133	136	148			312
	High*	152	149	138	120	128	131	143			3320
Gulf	High	133	125	101	119	118	152	111			453
East North Great Plain	Low	171	162	145	128	116	101	138	123		353
	High*	202	198	181	157	152	87	174	159		85
West North Great Plain	Low	148	138	119	99	107	88	95	62	101	4471
	High*	191	181	162	142	150	121	138	105	144	402
Rocky Mountain	Low	126	122	113	102	103	86	92	78	96	338
Southwest	Low	163	132	141	139	141	121	126	90	116	137
	High*	193	187	131	159	161	141	146	120	136	230
Demands (10^{12} Btu)		88	2343	2684	3858	1539	1631	772	745	212	

*Includes a 50¢/10^6 Btu charge for flue gas desulfurization.

Table B-8

2000 Utility Coal Costs
(1975 ¢/10^6 Btu Delivered)

Demand Region

Supply Region	Sulfur Content	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supplies (10^{12} Btu)
North Appalachia	Low	173	159	176	162	151	192	195			507
	High*	174	160	177	163	152	193	196			4888
South Appalachia	Low	175	163	160	152	145	177	183			6078
	High*	180	168	165	157	150	187	188			2482
Midwest	Low	208	198	183	158	169	173	189			418
	High*	201	191	176	151	162	166	182			4233
Gulf	High*	187	177	144	162	167	213	158			1221
East North Great Plain	Low	226	214	191	159	152	132	182	161		550
	High*	271	259	236	204	197	177	227	206		133
West North Great Plain	Low	195	182	156	131	140	102	124	80	137	10714
	High*	250	237	211	186	195	157	179	135	187	262
Rocky Mountain	Low	165	160	148	131	136	111	119	80	121	365
Southwest	Low	215	207	186	167	171	144	139	114	153	352
	High*	252	244	223	204	208	181	176	151	190	589
Demands (10^{12} Btu)		128	3609	3207	4200	1751	2432	1196	965	600	

*Includes a 62¢/10^6 Btu penalty for flue gas desulfurization.

Table B-9

1985 Industrial Coal Costs
(1975 ¢/10^6 Btu Delivered)

Demand Regions

Supply Region	Sulfur Content	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supplies (10^{12} Btu)
North Appalachia	Low	141	132	143	138	142	156	162			374
	High	92	83	94	89	93	107	113			3618
South Appalachia	Low	142	132	130	130	127	147	151			3890
	High	98	88	86	86	83	103	107			1589
Midwest	Low	169	162	150	130	138	142	156			312
	High	114	107	95	75	83	87	100			3320
Gulf	Low	120	97	77	86	77	82	53			453
East North Great Plain	Low	186	177	165	134	150	112	149	136		353
	High	172	163	151	120	136	98	135	122		85
West North Great Plain	Low	162	152	130	109	117	87	104	71	110	4471
	High	155	145	123	102	110	80	97	64	103	402
Rocky Mountain	Low	153	144	122	105	112	94	98	67	100	328
Southwest	Low	204	188	153	138	141	121	115	99	126	137
	High	184	168	133	118	121	101	95	79	106	230
Demands (10^{12} Btu)		34	602	512	1218	343	276	284	97	90	

Table B-10

2000 Industrial Coal Costs
(1975 ¢/10^6 Btu Delivered)

Demand Regions

Supply Region	Sulfur Content	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supplies (10^{12} Btu)
North Appalachia	Low	181	169	184	177	152	201	209			507
	High	120	108	123	116	121	140	148			4888
South Appalachia	Low	184	170	168	168	164	173	191			6078
	High	127	113	111	111	107	116	134			2482
Midwest	Low	217	208	192	165	176	181	199			418
	High	148	139	123	96	107	112	130			4233
Gulf	High	175	144	117	129	117	124	85			1221
East North Great Plain	Low	246	234	218	176	197	146	196	178		550
	High	229	217	201	159	180	129	179	161		133
West North Great Plain	Low	214	201	171	143	154	113	136	92	144	10714
	High	207	194	164	136	147	106	129	85	137	282
Rocky Mountain	Low	203	189	160	141	146	122	127	86	130	365
Southwest	Low	270	248	201	181	155	158	153	129	165	352
	High	245	223	176	156	160	133	128	104	140	589
Demands (10^{12} Btu)		52	877	895	1840	588	477	854	210	240	

Table B-11

1985 Supply of Natural Gas
(Delivered Cost In 1975 ¢/10^6 Btu)

Demand Regions

Supply Region	Sulfur Content	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supplies (10^{12} Btu)
New England											
Middle Atlantic			193								85
South Atlantic				193							213
East North Central					193						128
East South Central						193					170
West North Central					215		204		208		808
West South Central		247	236	210	221	220	208	193	225	247	16747
Rocky Mountain							210		205	225	1572
Pacific										193	1500
Alaska					222					349	1000
Atlantic OCS											0
Imports		425	425	425		425		425		425	Unlimited
Low Btu Gas											
North Appalachia	High		282		282						2714
South Appalachia	High			282		282					1192
Midwest	Low										
	High				380						2058
Gulf	High	384	373	347	358	357	345	330			281
East North Great Plain	Low				416		396		413		219
	High				397		373		390		53
West North Great Plain	Low				384		362		357	389	2772
	High				373		351		346	378	249
Rocky Mountain	Low				420		410		383	438	203
Southwest	Low								397	402	85
	High								365	370	143
Demands (10^{12} Btu)		253	1910	1552	1554	1486	1646	7099	1291	2857	

Table B-12

2000 Supply of Natural Gas
(Delivered Cost In 1975 ¢/10^6 Btu)

Demand Regions

Supply Region	Sulfur Content	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supplies (10^{12} Btu)
New England											
Middle Atlantic			219								98
South Atlantic				219							154
East North Central					219						92
East South Central		247	234			219					123
West North Central					241		230		234		586
West South Central		277	266	237	249	248	235	219	254	279	12135
Rocky Mountain							238		232	254	1140
Pacific										219	400
Alaska					379					412	1000
Atlantic OCS		225	225	225							700
Imported LNG		475	475	475		475		475		475	Unlimited
Low Btu Gas											
North Appalachia	High		301		301						3666
South Appalachia	High			299		299					1862
Midwest	High				401						2624
Gulf	High	422	411	382	394	393	380	364			757
East North Great Plain	Low				451		425		447	503	341
	High				424		398		420	474	82
West North Great Plain	Low				407		381		374	435	6643
	High				396		370		363	424	162
Rocky Mountain	Low				453		442		408	471	226
Southwest	Low								427	421	218
	High								387	381	365
Demands (10^{12} Btu)		237	1755	1422	4374	1579	1780	7886	1313	2908	

Table B-13

1985 Supply of Oil*
(Delivered Cost In 1975 ¢/10^6 Btu)

Demand Regions

Supply Region	Sulfur Content	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supplies (10^{12} Btu)
New England		224									98
Middle Atlantic			224								115
South Atlantic				224							200
East North Central					224						324
East South Central						224					409
West North Central							224				631
West South Central		236	23[illegible]	228	230	230	227	224	231	236	15409
Rocky Mountain									224		1910
Pacific					2[illegible]2			235	237	224	5400
Alaska					2[illegible]1		292		265	254	4300
Atlantic OCS											0
Imports		231	231	231	238	233	239	234	244	231	Unlimited
SYNCRUDE											
North Appalachia	Low										
	High	365	363								2424
South Appalachia	Low										
	High	367	365		354	364					1065
Midwest	High				358						2224
Gulf	High	328	326	320	322	321		3 6			304
East North Great Plain	Low				353		359		364		237
	High				344		340		345		57
West North Great Plain	Low				339		337		331		2996
	High				329		327		321		269
Rocky Mountain	Low				359		354		351		220
Southwest	Low								359	359	92
	High								323	329	154
Demands (10^{12} Btu)		3545	7630	6924	7833	2169	3113	4658	1945	5513	

*Assumed wellhead price: \$2.24/10^6 Btu.

Table B-14

2000 Supply of Oil*
(Delivered Cost In 1975 ¢/10^6 Btu)

Demand Regions

Supply Region	Sulfur Content	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supplies (10^{12} Btu)
New England		192									83
Middle Atlantic			192								98
South Atlantic				192							173
East North Central					192						285
East South Central						192					360
West North Central							192				555
West South Central		206	203	196	199	199	195	192	200	206	13210
Rocky Mountain									192		1680
Pacific								213	209	192	2310
Alaska					360					326	4300
Atlantic OCS		287	287	287							590
Imports		297	297	297	305	299	306	300	312	297	Unlimited
SYNCRUDE											
North Appalachia	Low										
	High	387	385								3275
South Appalachia	Low										
	High	386	384		383	383					1663
Midwest	High				376						
Gulf	High	361	358	351	354	354					2836
East North Great Plain	Low				386		380		388		329
	High				381		355		363		369
West North Great Plain	Low				348		346		340		133
	High				338		336		330		7178
											176
Rocky Mountain	Low				379		372		368		245
Southwest	Low								380	377	236
	High								343	340	395
Demands (10^{12} Btu)		3942	9029	9033	9621	2748	3828	6429	2593	7288	

*Assumed wellhead price: $2.87/$10^6$ Btu.

Table B-15

Prices and Quantities of Coal Distributed to Utilities
Assuming Best Available Control Technology*

(1985 in 1975 $)

	Sulfur lb S/10^6 Btu	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supply (10^{12} Btu)
North Appalachia	0.5	$\boxed{136}$ 5	$\boxed{126}$ 143	$\boxed{138}$	$\boxed{128}$	$\boxed{120}$	$\boxed{150}$	$\boxed{152}$			148
	2.0	$\boxed{136}$ 83	$\boxed{126}$ 2200	$\boxed{138}$	$\boxed{128}$ 538	$\boxed{120}$ 798	$\boxed{150}$	$\boxed{152}$			3619
South Appalachia	0.5	$\boxed{141}$	$\boxed{132}$	$\boxed{130}$ 1095	$\boxed{124}$	$\boxed{119}$ 591	$\boxed{143}$	$\boxed{147}$			1686
	1.5	$\boxed{141}$	$\boxed{132}$	$\boxed{130}$ 1589	$\boxed{124}$	$\boxed{119}$	$\boxed{143}$	$\boxed{147}$			1589
Midwest	0.6	$\boxed{157}$	$\boxed{149}$	$\boxed{138}$	$\boxed{120}$ 207	$\boxed{128}$	$\boxed{131}$	$\boxed{143}$			207
	3.0	$\boxed{157}$	$\boxed{149}$	$\boxed{138}$	$\boxed{120}$ 3113	$\boxed{128}$ 150	$\boxed{131}$	$\boxed{143}$			3320
Gulf	1.5	$\boxed{133}$	$\boxed{125}$	$\boxed{101}$	$\boxed{114}$	$\boxed{118}$	$\boxed{152}$	$\boxed{111}$ 453			453
East North Great Plains	0.6	$\boxed{221}$	$\boxed{212}$	$\boxed{195}$	$\boxed{171}$	$\boxed{166}$	$\boxed{151}$	$\boxed{188}$	$\boxed{173}$		353
	1.5	$\boxed{207}$	$\boxed{198}$	$\boxed{181}$	$\boxed{157}$	$\boxed{152}$	$\boxed{137}$	$\boxed{174}$	$\boxed{159}$		85
West North Great Plains	0.6	$\boxed{198}$	$\boxed{188}$	$\boxed{169}$	$\boxed{149}$	$\boxed{157}$	$\boxed{128}$ 1229	$\boxed{145}$	$\boxed{112}$ 745	$\boxed{151}$	4471
	0.9	$\boxed{191}$	$\boxed{181}$	$\boxed{162}$	$\boxed{142}$	$\boxed{150}$	$\boxed{121}$ 402	$\boxed{138}$	$\boxed{105}$	$\boxed{144}$	402
Rocky Mountains	0.6	$\boxed{176}$	$\boxed{172}$	$\boxed{163}$	$\boxed{152}$	$\boxed{156}$	$\boxed{136}$	$\boxed{142}$ 89	$\boxed{108}$	$\boxed{146}$ 212	328
Southwest	0.6	$\boxed{213}$	$\boxed{207}$	$\boxed{191}$	$\boxed{179}$	$\boxed{181}$	$\boxed{161}$	$\boxed{156}$	$\boxed{140}$	$\boxed{166}$	137
	0.8	$\boxed{193}$	$\boxed{187}$	$\boxed{171}$	$\boxed{159}$	$\boxed{161}$	$\boxed{141}$	$\boxed{136}$ 230	$\boxed{120}$	$\boxed{146}$	230
Demand (10^{12} Btu)		88	2343	2684	3858	1539	1631	772	745	212	
$P_{Average}$ ($/$10^6$ Btu)		1.36	1.26	1.30	1.21	1.20	1.26	1.22	1.12	1.46	

*Assuming no industrial or synfuel coal consumption.

Table B-16

Prices and Quantities of Coal Distributed to Utilities Assuming Current New Source Performance Standards*

(1985 in 1975 $)

	Sulfur lb S/10^6 Btu	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supply (10^{12} Btu)
North Appalachia	0.6	[135] 14	[125] 360	[137]	[127]	[119]	[149]	[155]			374
	2.0	[136] 74	[126] 1983	[138]	[128]	[120] 272	[150]	[156]			3618
South Appalachia	0.6	[137]	[128]	[126] 1901	[120] 1989	[115]	[139]	[143]			3890
	1.5	[141]	[132]	[130] 330	[124] 345	[119] 914	[143]	[147]			1589
Midwest	0.6	[157]	[154]	[143]	[125]	[133]	[136]	[148]			312
	3.0	[152]	[149]	[138]	[120]	[128]	[131]	[143]			3320
Gulf	1.5	[133]	[125]	[101] 453	[119]	[118]	[152]	[111]			453
East North Great Plains	0.6	[171]	[162]	[145]	[128]	[116] 353	[101]	[138]	[123]		353
	1.5	[202]	[198]	[181]	[157]	[152]	[87] 85	[174]	[159]		85
West North Great Plains	0.6	[148]	[138]	[119]	[99] 1524	[107]	[88] 1546	[95] 656	[62] 745	[101]	4471
	0.9	[191]	[181]	[162]	[142]	[150]	[121]	[138]	[105]	[144]	402
Rocky Mountains	0.6	[126]	[122]	[113]	[102]	[103]	[86]	[92] 116	[78]	[96] 212	338
Southwest	0.6	[163]	[132]	[141]	[139]	[139]	[121]	[126]	[90]	[116]	137
	0.8	[193]	[187]	[131]	[159]	[161]	[141]	[146]	[120]	[136]	230
Demand (10^{12} Btu)		88	2343	2684	3858	1539	1631	772	745	212	
$P_{Average}$ ($/$10^6$ Btu)		1.36	1.26	1.22	1.12	1.18	.88	.95	.62	.96	

*Assuming no industrial or synfuel coal consumption.

Table B-17

Prices and Quantities of Coal Distributed to Utilities
Assuming Best Available Control Technology*

(2000 in 1975 $)

	Sulfur lb S/10^6 Btu	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supply (10^{12} Btu)
North Appalachia	0.6	[174] 7	[160] 193	[177]	[163]	[152]	[193]	[196]			200
	2.0	[174] 121	[160] 3416	[177]	[163]	[152]	[193]	[196]			4888
South Appalachia	0.6	[180]	[168]	[165] 1400	[157]	[150] 1234	[182]	[188]			2634
	1.5	[180]	[168]	[165] 586	[157]	[150] 517	[182]	[188]			2482
Midwest	0.6	[201]	[191]	[175]	[151] 264	[162]	[166]	[182]			264
	3.0	[201]	[191]	[175]	[151] 3936	[162]	[166]	[182]			4233
Gulf	1.5	[187]	[177]	[144] 1221	[162]	[167]	[213]	[158]			1221
East North Great Plains	0.6	[276]	[264]	[241]	[209]	[202]	[182]	[232]	[211]		550
	1.5	[271]	[259]	[236]	[204]	[197]	[177]	[227]	[206]		133
West North Great Plains	0.6	[245]	[232]	[206]	[181]	[190]	[152] 2432	[174] 1196	[130] 965	[182] 235	10714
	0.9	[245]	[232]	[206]	[181]	[190]	[152]	[174]	[130]	[182]	262
Rocky Mountains	0.6	[215]	[210]	[198]	[181]	[186]	[161]	[169]	[130]	[171] 365	365
Southwest	0.6	[265]	[257]	[236]	[217]	[221]	[194]	[189]	[154]	[203]	352
	0.8	[252]	[244]	[223]	[204]	[208]	[181]	[176]	[151]	[190]	589
Demand (10^{12} Btu)		128	3609	3207	4200	1751	2432	1196	965	600	
$P_{Average}$ (\$/10^6 Btu)		1.74	1.60	1.57	1.51	1.50	1.52	1.74	1.30	1.75	

*Assuming no industrial or synfuel coal consumption.

Table B-18

Prices and Quantities of Coal Distributed to Utilities
Assuming Current New Source Performance Standards*

(2000 in 1975 $)

	Sulfur lb S/10^6 Btu	New England	Middle Atlantic	South Atlantic	East North Central	East South Central	West North Central	West South Central	Rocky Mountain	Pacific	Supply (10^{12} Btu)
North Appalachia	0.6	[173] 17	[159] 490	[176]	[162]	[151]	[192]	[195]			507
	2.0	[174] 111	[160] 3119	[177]	[163]	[152]	[193]	[196]			4888
South Appalachia	0.6	[175]	[163]	[160] 1986	[152]	[145]	[177]	[183]			6078
	1.5	[180]	[168]	[165]	[157]	[150]	[182]	[188]			2482
Midwest	0.6	[208]	[198]	[183]	[158]	[169]	[173]	[189]			418
	3.0	[201]	[191]	[176]	[151]	[162]	[166]	[182]			4233
Gulf	1.5	[187]	[177] 1221	[144]	[162]	[167]	[213]	[158]			1221
East North Great Plains	0.6	[226]	[214]	[191]	[159]	[152] 65	[132]	[182]	[161]		550
	1.5	[271]	[259]	[236]	[204]	[197]	[177]	[227]	[206]		133
West North Great Plains	0.6	[195]	[182]	[156]	[131] 4200	[140] 1686	[102] 2432	[124] 1196	[80] 965	[132] 235	10714
	0.9	[250]	[237]	[211]	[186]	[195]	[157]	[179]	[135]	[187]	262
Rocky Mountains	0.6	[165]	[160]	[148]	[131]	[136]	[111]	[119]	[80]	[121] 365	365
Southwest	0.6	[215]	[207]	[186]	[167]	[171]	[144]	[139]	[114]	[153]	352
	0.8	[252]	[244]	[223]	[204]	[208]	[181]	[176]	[151]	[190]	589
Demand (10^{12} Btu)		128	3609	3207	4200	1751	2432	1196	965	600	
$P_{Average}$ ($/$10^6$ Btu)		1.74	1.60	1.54	1.31	1.40	1.02	1.24	.80	1.25	

*Assuming no industrial or synfuel coal consumption.