Electric Energy Supply Systems : Description of Available Technologies

February 1985

**Prepared for the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830**

**Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
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PACIFIC NORTHWEST LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC06-76RLO 1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161

NTIS Price Codes
Microfiche A01

Printed Copy	
Pages	Price Codes
001-025	A02
026-050	A03
051-075	A04
076-100	A05
101-125	A06
126-150	A07
151-175	A08
176-200	A09
201-225	A010
226-250	A011
251-275	A012
276-300	A013

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ELECTRIC ENERGY SUPPLY SYSTEMS:
DESCRIPTION OF AVAILABLE
TECHNOLOGIES

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Prepared for
the U.S. Department of Energy
under Contract DE-AC06-76RL0 1830

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PREFACE

The results of the research contained in this report represent research efforts that were completed in 1981. However, because of contractual problems, this report is being published in January 1985. The authors recognize that since 1981 advances in the state of the art for technologies covered in this document have occurred that could alter the choices available to energy system planners. In most cases, however, the technical descriptions and the technical and economic relationships remain valid in 1985.

ACKNOWLEDGMENTS

Many people at Pacific Northwest Laboratory were involved with the development of this project, which spanned over a period of four years. Project management responsibilities were shared by Jack Eisenhower, Jeff King and Eric Rogers. Jack Eisenhower was the principal researcher and was responsible for the development of Chapters 2, 3 and 5 and Appendices A and B. Gary Stegen was responsible for the development of Chapter 4, and Jeff King was responsible for Chapter 1 and technical review of the entire document. Chapter 6 was developed based on information provided by Clifford C. Diamond, a consulting engineer to PNL. Paul McGoeey was responsible for the development of a computer simulation model based on information contained in this document.

Special appreciation is extended to Kenneth Klein, U.S. Department of Energy, who sponsored this research and provided guidance for the completion of the work; W. Bradford Ashton and L. Donald Williams of PNL, who provided line management support and guidance; and Vicki Lee of PNL, who provided excellent editorial assistance.

SUMMARY

When fuel supplies are a great distance from population centers where electricity is demanded, electric transmission can replace fuel transportation if the costs are comparable and if desirable technical and environmental conditions are met. In an effort to compare the cost and technical characteristics of advanced electric transmission technologies with fuel transportation alternatives, the Division of Electric Energy Systems (EES) of the U.S. Department of Energy (DOE) sponsored Pacific Northwest Laboratory (PNL) to examine and compare alternative coal-based electric energy systems. In this document, PNL examined and compared the vast coal resources of the western states for use in generating electricity for western and midwestern cities.

When comparing coal transportation with electric transmission as a means of delivering electric power, it is desirable to compare entire energy systems rather than just the transportation/transmission components because the requirements of each option may affect the requirements of other energy system components. For example, when compared to other options, additional generating capacity is required for long-distance electric transmission systems because of transmission losses. Likewise, coal slurry pipeline systems have larger coal requirements due to the moisture that must be removed before combustion. As a result, PNL has examined all components of a mine-to-load electric generating system based on coal resources from the Northern Great Plains.

PNL's assessment consists of two parts. The first part, which is the subject of this document, is a detailed description of the technical, cost, resource and environmental characteristics of each system component and technologies available for these components. The second part is a computer-based model that PNL has developed to simulate construction and operation of alternative system configurations and to compare the performance of these systems under a variety of economic and technical conditions.

This document consists of six chapters and two appendices. A more thorough description of coal-based electric energy systems is presented in the Introduction and Chapter 1. Each of the subsequent chapters describes technologies for five system components: Western coal resources (Chapter 2), coal

transportation (Chapter 3), coal gasification and gas transmission (Chapter 4), and electric power transmission (Chapter 6).

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INTRODUCTION

The coal resources of the Northern Great Plains comprise one of this country's principal resources for generation of electric power. These resources, however, are at considerable distances from major electrical load centers. For example, the vast coal reserves found in eastern Wyoming and Montana are 600 to 900 air miles from major Midwestern load centers and 800 to 1000 air miles from major West Coast load centers. Energy transportation is a major factor that must be considered prior to the development of these remote coal fields.

Several possibilities exist for long-distance transportation of energy: rail transport of coal, pipeline transport of coal slurry, pipeline transport of fuel gas derived from coal, and transmission of electric power by alternating or direct current. Variations within each of these transportation alternatives, combined with several power generation technologies, offer planners many technically feasible system configurations. The selection of an appropriate system requires consideration of several important factors, including technical performance, cost, and environmental and socioeconomic effects. Because of the complexity of these systems and the interrelationships of their elements, a comprehensive system assessment is necessary to account for every link in the fuel cycle from coal mining to the delivery of energy to the load center. Such an analysis would provide a thorough understanding of the aggregate system characteristics and could be used to select a preferred system.

Pacific Northwest Laboratory (PNL) has developed such an integrated system assessment methodology and a supporting data base to permit comparisons of selected technical, cost, environmental, and resource consumption characteristics of alternative large electric energy supply systems. The purpose of this work, sponsored by the U.S. Department of Energy (DOE), Division of Electric Energy Systems, is to provide a general purpose system assessment tool to guide the allocation of research and development funds to alternative energy conversion, transportation, and transmission technologies. Whereas PNL's assessment methodology allows detailed comparison of the characteristics of alternative supply systems, it does not rank or select preferred delivery configurations.

The electric energy supply systems examined in this report are based on coal as a primary energy resource and, in general, consist of the following basic components: coal extraction (mining), coal transportation, coal conversion (to fuel gas), electric power generation, and electric power transmission. Various technologies can be used to accomplish each of these operations. The Electric Power Research Institute (EPRI) predicted that the technologies considered in this study would be available for commercial operation by 1990, with the exception of integrated gasifier/combined-cycle plants and some high voltage direct current transmission technologies.

Although the methodology proposed for this study would be flexible enough to be applied to any coal resource or load center, the study's scope was limited to systems using Northern Great Plains subbituminous coal and delivering power to Midwestern and West Coast load centers. A nominal system capacity of 10 GWe, delivered to the load center, was selected.

This document is organized on the basis of the five components that comprise large-scale electric energy supply systems. Chapter 1 is a review of the component modules of large-scale electric energy supply systems and an overview of the technologies considered in this study. In addition, the detailed scope, assumptions and limitations of the analysis are outlined. Western coal resources are described in Chapter 2, which includes discussions of coal reserves, coal characteristics, coal procurement options, and Western mining practices. The focus is on subbituminous coal reserves of the Northern Great Plains region. Chapter 3 contains an overview of coal transportation technologies with detailed discussion of unit trains and slurry pipelines, the two most viable transport modes from the Northern Great Plains region. The option of using synthetic gas derived from coal to produce power is addressed in Chapter 4, which includes discussions of coal gasification, gas transportation, and electric power generation using coal-derived gas as fuel. Power generation using conventional coal-fired power plants is described in Chapter 5, including a discussion of flue gas emission control and waste heat rejection systems. In Chapter 6, both alternating current and direct current electrical transmission systems operating at various voltages are described. Appendix A reviews the major federal air-quality regulations affecting construction and operation of

coal-fired power plants. Appendix B presents an alternative methodology for computing operating and maintenance costs.

1.0 COAL-BASED ELECTRIC ENERGY SUPPLY SYSTEMS

Electric energy supply (EES) systems based on coal consist of several components. Each may be considered a critical link in the coal fuel cycle; if a single component fails, the entire system will eventually fail. The mission of each component may be accomplished by applying several different technologies, and every technology involved with the coal fuel cycle has a specific set of economic costs, environmental effects, and resource requirements associated with it. The ultimate purpose of this study is to compare the choices available to planners for meeting the electrical demand at a given load center. The purpose of this volume is to describe each technology and to provide technical, economic, environmental, and resource data for use in an analysis based on a simulation model.

Coal-based electric energy supply systems are characterized by five generic components:

- fuel extraction
- fuel transportation
- fuel conversion
- electric power generation
- electric power transmission.

A system may be defined by a set of technologies for each of these components, although fuel conversion may not be included in all systems (e.g., conventional steam power generation systems), and fuel transportation or electrical transmission may be absent in some systems (e.g., minemouth power production systems and load center power production systems, respectively). Every coal-based electric energy supply system requires fuel extraction and power generation as major components. Each of these major components is briefly described below.

Fuel Extraction - the process of recovering coal from the geologic formation in which it is found. This operation may include short-haul transportation in the vicinity of the mine, and coal preparation (breaking, sorting, and washing). If more elaborate coal preparation is involved, solvent refining, for example, coal beneficiation may be treated as a separate operation.

Because relatively little preparation is required of the Northern Great Plains subbituminous coal considered in this study, beneficiation was not considered as a separate operation.

Fuel Transportation - the process of transporting coal from the minemouth to the point of consumption and of transporting coal-derived fuels from the coal conversion facility to the electric power generating facility. For purposes of this study, coal consumption could occur either at a conventional coal-fired generating facility or in a coal conversion plant where coal is converted into a gaseous or liquid synthetic fuel for subsequent production of electricity. Systems using minemouth direct coal-fired generating facilities would not include a coal transportation module. Systems employing coal conversion facilities at intermediate locations might include two fuel transportation modules--coal from the mine to the conversion facility and coal-derived fuel from the conversion facility to the generating plant.

Fuel Conversion - the process of converting coal into a synthetic gaseous or liquid fuel. This process is characterized by emerging technologies and is not currently practiced on a large scale. This operation may be desirable in some cases to facilitate transportation and to better control potential environmental pollutants. Obviously, the coal conversion module would not be applicable to all electric energy supply configurations.

Electrical Power Generation - the process of generating electrical power from coal or coal-derived liquid or gaseous fuels. An essential module for any electric energy supply system, electric power generation could occur at the minemouth, the load center, or intermediate locations. Factors that would affect this decision include relative costs of fuel transportation and electric power transmission, process and cost economics obtained by integrating coal conversion and power generation facilities, availability of water for operation of waste heat rejection systems, and constraints on discharge of environmental pollutants.

Electric Power Transmission - the process of transporting electrical power from generation facilities to the load center. For purposes of this study, this module includes sending and receiving terminals and long distance

transmission lines. Distribution at the load center is not included. The electric transmission component is not present in systems using load center power generation.

The technologies considered in this study for each of these components were limited to those suitable for large-scale systems (approximately 10 GWe, delivered to the load center) and, in most cases, available for commercial operation by 1990. These are listed in Table 1.1.

Technologies considered for coal extraction are area strip mining and open pit mining. These are the principal coal extraction methods used for the sub-bituminous coal deposits of the Northern Great Plains region and probably will be used through 1990 for the large-scale operations considered in this study. The depth of treatment given to coal extraction technologies is more limited than to other technologies because of the emphasis on energy transportation.

A variety of transportation options is available for moving coal from mine to conversion or generation plant, including rail transport, slurry pipeline transport, barge transport, trucks and conveyor systems. Unit train operations

TABLE 1.1. Technologies Considered in the Electric Energy Supply Systems Study

<u>Coal Extraction</u>	<u>Fuel Transportation</u>	<u>Coal Conversion</u>	<u>Power Generation</u>	<u>Electric Transmission</u>
• Area Strip Mining	• Unit Train	• Coal Gas-ification: Low Btu Gas Med Btu Gas Substitute Natural Gas	• Pulverized Coal-fired Power Plants	• AC Trans- mission: 345 kV 500 kV 765 kV 1100 kV
• Open Pit Mining	• Coal Slurry Pipeline		• Gas-fired Combined-Cycle Power Plants	
	• Gas Pipeline	• Integrated Gasification/ Combined-Cycle Power Plants		• DC Trans- mission: ± 400 kV ± 500 kV ± 600 kV ± 750 kV

and slurry pipeline transportation offer the greatest potential for movement of coal in the quantities and distances required in this study. Truck and conveyor transport is clearly not feasible for the applications considered in this study. Barge transport, while possibly usable in a multi-modal transportation system to certain West Coast, Great Lakes, and Mississippi Valley load centers, was also not considered in this study.

Several processes are currently under development for conversion of coal to liquid and gaseous synthetic fuels. Those holding the greatest promise for commercial availability around 1990 include low and medium Btu gasification and substitute natural gas (SNG) production. Because of the expense of transporting low or medium Btu gas and production efficiencies achievable by integrating gasification and power generation processes, the integrated coal gasifier/combined-cycle power plant appears to be the most promising technology for use of coal-derived gas for electric power production. Substitute natural gas could be transported substantial distances by pipeline, allowing use of remote gas-fired power plants based on a coal primary energy resource. The economics of SNG production are such, however, that this option is unlikely to be economically competitive for electric power production using conventional or advanced combustion-based power plants.

Electric power generation options holding promise for application to coal-based electric energy supply systems by 1990 include pulverized coal-fired power plants and combined-cycle power plants fired by coal-derived gas. The latter may be free-standing plants or integrated with coal gasifiers. As discussed previously, because of the economics of SNG production, it is unlikely that free-standing combined-cycle plants would be used. An additional option would be the use of conventional gas-fired, steam-electric plants, although the superior heat rate of combined-cycle units would likely make the latter preferred in large-scale operations. Thus, conventional gas-fired steam-electric units were not considered. Emerging generating technologies not considered in this study include atmospheric fluidized-bed combustion steam-electric plants, pressurized fluidized-bed combustion combined-cycle plants and fuel cells fired by coal-derived gas. These technologies promise improved efficiencies, better control of atmospheric emissions and reduced water consumption for waste heat

rejection. Forecasted availability for commercial operation for atmospheric and pressurized fluidized bed combustion technology is 1993 and 1995, respectively (EPRI 1982), and are outside the scope of this work. Availability of phosphoric acid fuel cells for commercial operation is forecasted for 1986; however, it is unlikely that this type of fuel cell would be used in central station operation. The molten carbonate fuel cell may be preferred. Because of the fuel cell's high operating temperatures, cogenerating waste heat steam boilers could be used. Projected commercial service for installations of this type is 1995 or later (EPRI 1982).

Alternating current transmission voltages of 345, 500, and 765 kV are currently in commercial operation. Higher voltages offer the potential for more economical transmission of very large quantities of energy because of the reduced number of circuits required and possibly reduced environmental impact through smaller land requirements. Circuits in the 1100 kV range are currently being tested by the Bonneville Power Administration; that voltage is considered in this study because of the possibility of commercial applications by 1990.

Direct current transmission is characterized by high terminal costs relative to line costs for distances of several hundred miles or less. Use of two conductors per circuit, in lieu of three as required in alternating current transmission, results in lower line, tower and right-of-way costs, making dc transmission attractive for long distance point-to-point transmission. The advent of solid-state converter technology improves the attractiveness of direct current transmission for applications to systems considered in this study. Voltages up to ± 600 kV are intended for systems currently under construction. Higher voltages (± 750 , ± 800 kV) are under consideration.

This study was limited in several ways because of the complexity of large-scale delivery systems and the multitude of factors affecting implementation of an actual system. In general, the study was an examination of generic coal-based electric energy supply systems. The focus was based on Northern Great Plains coal from Wyoming and Montana for electric power at Midwest and West Coast load centers. Outside of this, no site-specific analysis was performed.

In determining site characteristics that would affect power plant performance, cost of power lines, coal quality or other items, typical values, and assumptions believed to be representative of the region were used.

One serious limitation to construction and operation of such a large-scale (10 GW) energy supply system is the environmental impacts resulting from collocation of energy production and transport facilities. In particular, centrally sited gasification facilities, electric generating plants, and lower voltage transmission lines could cause considerable environmental degradation due to air emissions, water effluents, land use, water consumption, and visual and auditory impacts. This examination of environmental effects is limited to an overview of relevant laws affecting release of pollutants and an accounting of environmental releases from mining, power generation, and delivery systems. Siting regulations and limitations were not examined.

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2.0 WESTERN COAL RESOURCES

The purpose of this chapter is to examine and describe selected Northern Great Plains coal resources that could be used for production of bulk electric power. Our analysis focuses on the extensive subbituminous coal resources of Wyoming and Montana because of their high quality, large deposits, and accessibility for mining. The strippable coal reserves of the Powder River Basin are particularly suitable for mining coal to be used for bulk electric power generation. Although other coal resources of the Northern Great Plains would be suitable for this purpose, we have limited our examination to subbituminous resources of Wyoming and Montana.

This chapter is divided into four sections, each describing an important aspect of Western coal use for electric generation. Coal reserves in Wyoming and Montana and their ability to support 10,000 MW of electrical production are addressed first. Following is a discussion of coal characteristics that outlines the major qualities of coal and their effect on power generation. The third section contains an outline of coal procurement options. Captive mining, contract purchasing, and spot purchasing are described, followed by a discussion of coal price trends. In the last section, Western mining methods and mining regulations are briefly reviewed. Included are evaluations of environmental effects and resource consumption.

2.1 COAL RESERVES IN WYOMING AND MONTANA

The extensive coal resources of Wyoming and Montana account for 35% of the total coal resources in the U.S. Of the estimated 937 billion tons of in-place coal resources in Wyoming, 26.3 billion tons of strippable reserves were thought to be remaining as of January 1, 1978. Because this estimate is based on a limited number of mapped and explored areas, reserves may amount to the ten times this estimate (Keystone 1978).

Although less is known about the potential coal reserves in Montana, an estimated 50 billion tons of strippable subbituminous and lignite coal exist in eastern Montana alone. Total resources in Montana have been estimated at 449 billion tons (Keystone 1978).

Strippable coal reserves in Wyoming and Montana that can be utilized for electric power generation are examined in the following subsections. Scenarios that provide 10,000 MW of electricity are used as a basis for the discussion.

2.1.1 Wyoming

Wyoming's coal fields, containing 24% of the nation's coal resources under less than 6,000 ft of overburden, boast some of the most promising reserves in the U.S. Of the 937 billion tons of in-place resources, 26.3 billion tons are strippable subbituminous reserves. The strippable deposits are the easiest and least costly to remove, making these reserves most desirable to coal producers and electric utilities (Keystone 1978).

The great advantage of Wyoming coal fields is that the stripping ratio (tons of overburden removed per ton of coal removed) is quite low. For example, in northeastern Wyoming the Wyodak seam, which is 70 to 90 ft thick, lies just below the surface. In addition, the sulfur content of Wyoming coal is quite low. Ninety-nine percent of Wyoming coal contains less than 1% sulfur compared to 2 to 5% in most Eastern coals (Decarlo 1976).

Figure 2.1 shows the location of major coal-bearing areas in Wyoming and Montana. These regions are divided into numerous coal fields and specific beds. Table 2.1 gives a detailed breakdown of the remaining strippable deposits in Wyoming by major coal regions and coal beds. Over 70% of these deposits are contained in the Wyodak bed in the Powder River basin.

The quality of Wyoming coal varies among regions and beds. The main parameters that determine the quality and that influence the price of coal are as follows:

- heat value (Btu/lb)
- sulfur content (%)
- ash content (%)
- moisture content (%)
- grindability (Hardgrove index).

The ranges of values for the above parameters are listed in Table 2.2 for four geographic regions in the state. The five major quality parameters and other attributes are discussed in Section 2.2.

FIGURE 2.1. Wyoming and Montana Coal-Bearing Areas (Keystone 1978)

The delivery to a load center of 10 GW of electric power at a 90% load factor would require 45 million tons of coal^(a) annually for minemouth power plants (assuming a 92% transmission efficiency) or approximately 42 million tons for load-center power plants. This amounts to a total lifetime consumption of 1.3 to 1.4 billion tons of coal for a 30-year system life.

As Table 2.1 indicates, only the Powder River basin and Green River Region can support the coal requirements for a one-site, 10,000 MW production scenario if coal is to be supplied exclusively by surface mining. If a two-site

(a) Based on 9100 Btu/lb average coal heat value and 9700 Btu/kWh power plant heat rate.

TABLE 2.1. Strippable Coal Reserves of Wyoming (January 1, 1978)(a)

Coal Bearing Region	Strippable Deposits	Coal Bed(s) (Average Thickness in ft)	Acreage Estimate	Original/ Estimated Reserves to 1/1/69	Production and Mining Losses Since 1/1/69	Remaining Strippable Reserves to 1/1/78
Power River Coal basin	Acme-Kleenburn ^(b)	Monarch and Dietz No. 3 (23 ft)	2,029.0	39,300,000	12,000,000	27,300,000
	Clear Creek	Canyon (11.2 ft)	9,337.6	184,900,000	--	184,900,000
	Dave Johnston	School (38 in)	2,418.0	126,200,000	26,900,000	108,800,000
		Badger (16 ft)	390.0	9,500,000	--	
	Dry Cheyenne	F (7.6 ft)	13,260.8	179,500,000	--	179,500,000
	Lake DeSmet	Healy (163 ft)	3,520.0	1,000,000,000	--	1,000,000,000
	Spotted Horse	Felix (12.5 ft)		480,700,000	--	480,700,000
		Smith (10.0 ft)		178,000,000	--	178,000,000
		Local (10.0 ft)	36,736.0	58,300,000	--	58,300,000
	Sussex	Wasatch Fm. Coal (11.8 ft)	651.0	13,600,000	--	13,600,000
	Wyarno-Verona ^(b)	PK (11 ft)		200,000,000	--	200,000,000
		Ulm 2 (20 ft)		990,000,000	--	990,000,000
		Ulm 1 (30 ft)		543,000,000	--	543,000,000
		Other Wasatch coals (10 ft +)		67,000,000	--	67,000,000
	Wyodak	Wyodak-Anderson (71 ft); Anderson (D) and Canyon (E)	115,282.0	19,000,000,000	45,300,000	18,954,700,000
		SUBTOTAL	223,624.4+	23,070,000,000	84,200,000	22,985,800,000
Green River Coal Region	Black Buttes	Almond, Lance, Ft. Union and Wasatch Fm. coals (12 ft)	3,889.0	82,600,000	--	82,600,000
	Creston-Cherokee ^(b)	Upper Cherokee (B) (11 ft); Lower Cherokee (C) (25 ft); Other Ft. Union Fm. coals	4,204.0+	360,000,000	--	360,000,000
	Jim Bridger	Deadman (30 ft)	4,708.0	250,000,000	14,000,000	236,000,000

TABLE 2.1. (contd)

Coal Bearing Region	Strippable Deposits	Coal Bed(s) (Average Thickness in ft)	Acreage Estimate	Original/ Estimated Reserves to 1/1/69	Production and Mining Losses Since 1/1/69	Remaining Strip- pable Reserves to 1/1/78
	Leucite Hills ^(b)	Ft. Union Fm. coals		168,000,000	--	168,000,000
	Northern Little Snake River ^(b)	Ft. Union Fm. coals (15 ft); Lance Fm. coals (8 ft); Mesaverde Fm. coals (6 ft)	15,901.0+	269,600,000	--	269,600,000
	Red Desert	Battle 2 & 3 (7 ft)	2,938.0	38,100,000	--	38,100,000
		Sourdough, Monument, and Tierney (6.8 ft)	27,469.0	458,900,000	--	458,900,000
		Hadsell 2 (7.7 ft)	2,874.0	39,800,000	--	39,800,000
		Creston 2 & 3 (14 ft)	3,846.0	125,600,000	--	125,600,000
		Latham 3 & 4 (5.7 ft)	6,893.0	70,700,000	--	70,700,000
	Salt Wells ^(b)	Mesaverde Group coals		60,000,000	--	60,000,000
		SUBTOTAL	72,722.0+	1,923,300,000	14,000,000	1,909,300,000
Hams Fork Coal Region	Adaville	Adaville Fm. coals (44 ft)	12,800.0	1,000,000,000	30,000,000	1,034,800,000
	South Haystack ^(b)	Adaville Fm. coals (40 ft)	1,544.0	64,800,000	--	64,800,000
		SUBTOTAL	14,344.0	1,064,800,000	30,000,000	1,034,800,000
Hanna Coal Field	Carbon Basin ^(b)	Finch (10 ft); Johnson (10 ft); Other Hanna Fm. coals	2,725.0+	79,000,000	--	79,000,000
	Hanna Basin	Hanna, Ferris & Medicine Bow Fm. coals (21 ft)	8,400.0	313,000,000	65,100,000	247,900,000
		SUBTOTAL	11,125.0	392,000,000	65,100,000	326,900,000
Bighorn Coal Basin	Grass Creek	Mayfield (35 ft)	97.0	18,600,000	--	18,600,000
		SUBTOTAL	97.0	18,600,000	--	18,600,000
		GRANDTOTAL	321,912.4+	26,468,700,000	193,300,000	26,275,400,000

(a) (Keystone, 1978).

(b) Includes new reserve base derived from company reports and/or government publications.

TABLE 2.2. Wyoming Coal Characteristics^(a)

Geographic Area	Rank	Bed Thick- nesses (ft)	Moisture ^(b) (%) (AR) ^(c)	Ash ^(b) (%) (AR)	Sulfur ^(b) (%) (AR)	Heat Value ^(b) (Btu/lb) (AR)	Hardgrove ^(b) Grindability Index
Northeastern Wyoming	Lignite	Max: 220	Range: 20.3	Range: 4.4	Range: 0.45	Range: 7,550	Range: 30
	Subbituminous ^(b)	Range: ^(b) 12-100	to 29.8	to 11.4	to 0.6	to 9,700	to 53
	Bituminous	Ave.: ^(b) 70	Avg.: 26.3	Ave.: 7.9	Ave.: 0.54	Ave.: 8,300	Avg.: 45
Southern Wyoming	Subbituminous ^(b)	Max: 50	Range: 10.2	Range: 4.2	Range: 0.4	Range: 9,270	Range: 45
	Bituminous ^(b)	Range: ^(b) 4-35	to 20.5	to 12.2	to 0.9	to 11,700	to 80
		Avg.: ^(b) 16.5	Avg.: 12.4	Avg.: 7.1	Avg.: 0.52	Avg.: 10,500	Avg.: 49
Western Wyoming	Subbituminous ^(b)	Max: 110	Range: 20.4	Range: 3.0	Range: 0.6	Range: 9,500	Range: 53
	Bituminous	Range: ^(b) 5-20	to 20.9	to 4.8	to 0.7	to 10,200	to 57
		Avg.: ^(b) 16.5	Avg.: 20.8	Avg.: 4.5	Avg.: 0.6	Avg.: 9,600	Avg.: 54
Northcentral Wyoming	Subbituminous ^(b)	Max: 50	Range: 10.7	Range: 5.0	Range: 0.3	Range: 10,730	Range: 30
	Bituminous	Range: ^(b) 5-20	to 12.8	to 9.4	to 0.6	to 11,246	to 80
		Avg.: ^(b) 13	Avg.: 12.3	Avg.: 7.4	Avg.: 0.4	Avg.: 10,970	Avg.: 49

(a) Keystone 1978. Table compiled by Geological Survey of Wyoming, March 1978.

(b) Beds currently mined.

(c) AR = As received.

(5000 MW each) production scenario were implemented, any combination of Powder River Basin, Green River Region, and Hams Fork Region sites could satisfy the coal requirements. A third scenario of five 2000 MW production sites can be satisfied with any combination of regions from Table 2.1 except the Bighorn basin, which only has 18.6 million tons of strippable reserves. In this third scenario, one region would require two sites.

These production scenarios are feasible only for coal reserves. Constraints caused by geography, mining equipment capabilities, water availability, environmental laws, and state and federal regulations can render any particular site infeasible.

2.1.2 Montana

The coal reserves in Montana are less well known than those in Wyoming, even though coal fields cover over one third of the land mass of the state. Total coal resources in Montana are estimated at 449 billion tons by the U.S. Geological Survey. Of this total, 35 billion tons are strippable subbituminous reserves and 15 billion tons are strippable lignite reserves (Keystone 1978).

The bulk of Montana's coal is contained in the Fort Union formation in the eastern portion of the state (Figure 2.1). This area contains the second and third largest producing mines in the U.S., with a combined annual output of over 20 million tons in 1977 (Keystone 1978). This figure is about half of the coal required annually for the production of 10,000 MW.

At least six coal fields in Montana have enough strippable deposits to support the one-site, 10,000 MW production scenario. The six fields are listed in Table 2.3 along with the ash, sulfur and heat content of the coal. Several more fields could support the two-site (5000 MW each) and five-site (2000 MW each) production scenarios.

Montana's coal resources are being developed somewhat slower than Wyoming's. In 1977 Montana mines produced 29.3 million tons compared to Wyoming's 44.5 million tons (Keystone 1978). This difference is partially due to the easily accessible and slightly higher quality coal in Wyoming. In addition, Montana has a 30% severance tax on all coal that leaves the state compared with 17% for Wyoming (Western Energy Update 1980).

TABLE 2.3. Selected Strippable Subbituminous Deposits in Montana^(a)

Field	Coal Bed	Estimated Reserves (millions of tons)	Ash Content ^(b) (%)	Sulfur Content ^(b) (%)	Heat Content ^(b) (Btu/lb)
Ashland	Knobloch	2696	4.8	0.15	8421
Decker	Anderson- Dietz 1&2	2240	4.0	0.40	9652
Otter Creek	Knobloch	2070	4.7	0.36	8468
Canyon	Wall	2884	4.6	0.30	9088
Hanging Woman Creek	Anderson	1583	4.9	0.29	8496
Colstrip	Rosebud	1439	8.5	0.75	8750

(a) Keystone 1978.

(b) "As received" basis.

2.2 COAL CHARACTERISTICS

The efficiency, reliability and cost of power generation depend on, among other factors, the qualities and characteristics of the fuel that is used. Coal quality can vary among regions, within a region, within a field, and even within seams and beds.

Coal qualities that can affect the cost of power generation are outlined below. Some qualities have a significant impact on costs and are easily quantifiable. Others, however, have indirect or unquantifiable impacts but are included here for completeness.

2.2.1 Heat Value (Btu/lb)

The most important factor in determining the price of coal is the heat value. Heat value is a measure of coal's potential heat energy expressed in Btu/lb. Other factors being equal, the higher a coal's heat value the higher price it will bring. Coal is classified by the American Society for Testing Materials (ASTM) into four "ranks", generally based on heat energy:

- anthracitic
- bituminous (high, medium and low volatility)

- subbituminous
- lignitic.

The distinction between low- and medium-volatile bituminous and anthracite coal is made by the fixed carbon content. The distinction among high-volatile bituminous, subbituminous and lignite coal is made by heat value. High-volatile bituminous coal ranges from 10,500 to 14,000 Btu/lb; subbituminous coal ranges from 8300 to 11,500 Btu/lb; and lignite contains less than 8300 Btu/lb. Table 2.4 shows the complete ASTM classification of coals by ranks.

Most strippable reserves in Wyoming and Montana are classified as subbituminous. Coal deposits found in this area generally range from 8500 to 10,000 Btu/lb. Existing mines in the region produce coal toward the higher end of this range (Keystone 1980).

2.2.2 Sulfur Content (% by Weight)

Sulfur content is important because coal combustion releases sulfur compounds that may cause human health effects when released to the atmosphere. The U.S. Environmental Protection Agency (EPA) has set maximum sulfur dioxide (SO_2) emission standards for new fossil-fired power plants. Because the standards are based on pounds of SO_2 emitted per million Btu, the level of SO_2 removal needed to comply with EPA's New Source Performance Standards (NSPS) for new coal-fired plants varies depending on the heat value and sulfur content of the coal being burned. Coal is classified into three categories, described below by the New Source Performance Standards (Allen and Kaslow 1979):

- Category 1 - Use of coal producing uncontrolled SO_2 emissions that are equal to or less than $2 \text{ lb}/10^6 \text{ Btu}$ requires removal of 70% of potential SO_2 emissions.
- Category 2 - Use of coal producing uncontrolled SO_2 emissions between $2 \text{ lb}/10^6 \text{ Btu}$ and $6 \text{ lb}/10^6 \text{ Btu}$ requires SO_2 emissions to be limited to $0.6 \text{ lb}/10^6 \text{ Btu}$. Therefore, the percent removal required for coals in this category will vary depending on their potential uncontrolled emissions.

TABLE 2.4. Classification of Coals by Rank^(a) (ASTM D 388)^(b)

Class	Group	Fixed Carbon Limits, % (Dry, Mineral- Matter-Free Basis)		Volatile Matter Limits, % (Dry, Mineral-Matter Free Basis)		Calorific Value Limits, Btu/lb (Moist, ^(c) Min- eral-Matter-Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	--	--	2	--	--	Nonagglomerating
	2. Anthracite	92	98	2	8	--	--	
	3. Semianthracite ^(d)	86	92	8	14	--	--	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	--	--	Commonly agglomerating ^(f)
	2. Medium volatile bituminous coal	69	78	22	31	--	--	
	3. High volatile A bituminous coal	--	69	31	--	14,000 ^(e)	--	
	4. High volatile B bituminous coal	--	--	--	--	13,000 ^(e)	14,000	
	5. High volatile C bituminous coal	--	--	--	--	11,500 10,500 ^(f)	13,000 11,500	
III. Subbituminous	1. Subbituminous A coal	--	--	--	--	10,500	11,500	Nonagglomerating
	2. Subbituminous B coal	--	--	--	--	9,500	10,500	
	3. Subbituminous C coal	--	--	--	--	8,300	9,500	
IV. Lignitic	1. Lignite A	--	--	--	--	6,300	8,300	Nonagglomerating
	2. Lignite B	--	--	--	--	--	6,300	

(a) (Babcock and Wilcox 1978).

(b) This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free Btu/lb.

(c) Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

(d) If agglomerating, classify in low-volatile group of the bituminous class.

(e) Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

(f) It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

- Category 3 - Use of coal producing uncontrolled SO_2 emissions between $6 \text{ lb}/10^6 \text{ Btu}$ and $12 \text{ lb}/10^6 \text{ Btu}$ requires removal of 90% of potential SO_2 emissions. The absolute upper limit for all coals is $1.2 \text{ lb}/10^6 \text{ Btu}$. Therefore, coals with potential SO_2 emission above $12 \text{ lb}/10^6 \text{ Btu}$ may not be burned unless SO_2 removal exceeds 90% and the $1.2 \text{ lb}/10^6 \text{ Btu}$ limit is met.

Much of the strippable coal found in Montana and Wyoming falls into Category 1, requiring 70% SO_2 removal. Although this coal has an economic advantage over most Eastern coal (which requires 90% removal at a greater cost), it is not sufficient to offset the high transportation cost of the long west-east coal haul to Eastern coal-fired plants.

2.2.3 Moisture Content (% by Weight)

Moisture in coal exists in two forms: surface moisture and inherent moisture. Surface moisture can cause problems in handling coal at the coal bunker, feeder and pulverizer.

Coals having high inherent moisture (reported as the moisture content) can ball up in the pulverizer and inhibit grinding. Therefore, coal must be dried in the pulverizer by preheated air. This reduces the power requirements for the pulverizer and increases the fineness of the coal particles used in combustion. However, inherent moisture, whether evaporated in the pulverizer or in the furnace, causes a reduction in combustion efficiency.

Western coal generally has higher inherent moisture than Eastern coals. Wyoming and Montana coals have moisture contents of 10% to 30% (by weight) compared to 1% to 4% for coals found in Pennsylvania and West Virginia (Keystone 1979).

Although the greater inherent moisture in Western subbituminous coal reduces boiler efficiency, it also reduces nitrogen oxide (NO_x) emissions (Heil and Durrant 1978). This condition is reflected in the NSPS for NO_x , which is stricter for subbituminous coals than for bituminous coals.

2.2.4 Ash Content (% by Weight)

Ash content affects generation costs because residual ash must be removed and disposed of after combustion. In pulverized coal-fired units, about 80% of the coal ash is captured as fly ash suspended in the flue gases. The other 20% appears as bottom ash in the boiler. In cyclone coal-fired units this ratio is about 30% fly ash/70% bottom ash (in slag form) (Babcock and Wilcox 1978). These boiler types are described in Chapter 5.

Ash may be sold to cement manufacturers or used in highway construction if these markets are near power plants. However, in many cases ash must be disposed of as waste. For coal-fired plants with SO₂ scrubber systems, the ash and scrubber sludge are disposed of together. In 1978, capital costs for disposal of ash and scrubber sludge for a 1000 MW coal-fired plant burning Western coal were estimated at \$6.7 to \$29.4/kW (Jones et al. 1978).

The ash content of Western subbituminous coals ranges from about 4 to 10% by weight, while Eastern bituminous coals are generally higher with about 6 to 26% ash (Keystone 1979). As a result, ash disposal costs for Western coals are slightly lower.

Several constituents in coal ash affect boiler efficiency and generation costs. Among the more important elements in coal ash are sodium and calcium. Fouling, the accumulation of combustion wastes on boiler components, has been linked to the sodium content of coal ash. A Foster Wheeler Corporation report noted that reduction in operating reliability can be expected when the amount of sodium in coal ash exceeds 4% (Nelken and Altman 1975). However, fouling is also related to coal rank. Some research indicates that lignite ash may foul three to four times as much as subbituminous coal ash having similar sodium content. Wyoming and Montana subbituminous coals have been classified as having low to medium fouling potentials in pilot plants tests (Tufte et al. 1976).

Calcium, which has been observed in large amounts in some Wyoming coals, can be used to supplement alkali requirements in SO₂ removal processes. As a result, limestone requirements for SO₂ removal systems may be reduced, lowering operating costs.

Ash fusion temperatures of coal are one of the main determinants of slagging potential in low rank coal. (Slagging is the formation of ash deposits on boiler walls.) Lower ash fusion temperatures result in higher slagging potential. By properly sizing a boiler to burn a specific grade of coal and by properly locating soot blowers, slagging problems due to low ash fusion temperatures can be reduced.

2.2.5 Grindability Index (Hardgrove)

Grindability is a measure of how well a coal will perform in a pulverizer. Coals of low rank, such as lignite, have low grindabilities and require larger pulverizers that result in high preparation costs. Bituminous coals have high grindabilities and therefore low preparation costs.

Subbituminous coals found in Wyoming and Montana have low to medium grindabilities and usually require larger pulverizers than Eastern coals. Figure 2.2 shows the general relationship between coal rank and grindability. These characteristics may vary for individual coals.

FIGURE 2.2. Grindability Versus Coal Rank

2.2.6 Reference Coal

For the purposes of performing technical and economic analysis, a reference coal has been specified, as shown in Table 2.5. This coal is representative of those found in Wyoming and Montana coal fields and provides the basis for further analysis in this report. It has a heat content of 9100 Btu/lb, contains 10% ash, 0.8% sulfur, 20% moisture and has a Hardgrove grindability of 50.

TABLE 2.5. Reference Coal Analysis - Wyoming Subbituminous

Heat Content	9100 Btu/lb
Sulfur Content	0.8%
Moisture Content	20%
Fixed Carbon	38%
Volatile Matter	32%
Ash Content	10%
Grindability (Hardgrove)	50
<u>Ash Analysis</u>	<u>% by Weight</u>
SiO ₂	30.5
Al ₂ O ₃	15.7
Fe ₂ O ₃	6.6
CaO	25.5
MgO	3.7
Na ₂ O	0.3
K ₂ O	0.5
TiO ₂	0.6
P ₂ O ₅	0.4
SO ₃	16.4
<u>Fussion Analysis</u>	<u>°F</u>
Initial Deformation Temperature	2260
Softening Temperature	2600
Hemispherical Temperature	2640
Fluid Temperature	2700

2.3 COAL PROCUREMENT OPTIONS^(a)

The coal mining industry has been characterized as being highly competitive. Even though the top 15 companies accounted for about 40% of all coal produced in 1977, no single company was able to influence coal prices. Furthermore, the portion of coal produced by the top 15 companies dropped by 3.9% from 1976 to 1977 (Keystone 1978). While it can be argued that regional markets could upset competition (especially in the West), the existence of captive mines has prevented this situation. Although entering the mining industry requires considerable financial, management and technical expertise, large coal users often have these skills in-house. For example, electric utilities, steel companies, and oil companies have successfully entered the coal mining industry.

The major coal procurement options available to electric utilities are outlined below. Emphasis will focus on procurement practices common to the Western coal-producing region of the U.S.

2.3.1 Captive Mines

Steel companies or electric utilities may enter coal production to supply inputs for their mills or generating plants. This backward integration of coal-consuming industries offers several advantages. A utility mining its own coal secures a future supply of fuel and is thereby protected from possible shortages. In addition, coal cost will directly reflect production cost and thus insulate the utility from market instabilities. On the open market ("spot market"), the price of coal may reflect prices of fuel substitutes, such as oil, in addition to the mining costs of the coal. Coal price increases paralleled those of oil during the 1973-74 oil embargo, but this price link has not been observed in more recent oil price increases (Mann and Heller 1979).

Electric utilities traditionally have been less active in captive production than steel companies due to the good availability of steam coal from many sources. Steel companies, which require specific grades of coal, often seek to secure future supplies of coking coal by operating captive mines.

(a) This section draws heavily from a 1977 report prepared by Charles Rivers Associated, Inc., entitled Coal Price Formation.

Electric utilities may directly own a captive mine or may organize a separate subsidiary to handle mining operations. The latter option allows the utility to operate at optimal production levels and to take advantage of favorable market conditions by selling surplus coal on the spot market.

Public utilities have been restricted somewhat from becoming directly involved in coal production by the Public Utilities Holding Company Act. Theoretically, coal mined by a utility should be used by that utility for the generation of power. Conceivably, though, utility-mined coal could be sold on the open market if appropriate adjustments were made in the utility's rate structure to account for revenues received from the sales. A subsidiary, however, probably would not be bound by those restrictions.

In 1977, 17 utilities or their subsidiaries produced more than 68 million tons of coal from captive mines, accounting for 14% of the total coal consumed by the industry. This trend toward captive production is especially prevalent in Wyoming and Montana where in 1977 an estimated 31 million tons were produced from captive mines by public utilities (Keystone 1978).

The decision of a utility to mine its own coal usually depends on its assets, its managerial and technical capability, and potential and existing contractual arrangements with existing mining companies.

2.3.2 Contract and Spot Coal

While captive mines supply about 14% of the coal consumed by utilities, the balance is obtained from the commercial market. The two commercial coal procurement options by which utilities obtain commercial coal are to contract for coal or to buy it on the spot market.

Contracts between utilities and mining companies can extend from a few years to more than thirty years. A contract specifies the quality of coal to be purchased and includes a penalty system for Btu content below contract specification. Likewise, bonuses may be given for Btu content above the specified quality.

Spot coal is obtained from the open market. Coal producers who work contract mines can sell their surplus on the spot market. In fewer instances coal producers will operate mines solely for spot sales. These are typically

marginal mines, which operate only when spot prices are high. Due to potential market instabilities, financing for totally spot mines is more difficult to obtain than financing for contract mines. As a result, coal producers have opted for some combination of spot and contract production. A representative of one coal producer has stated that his firm likes to have at least 75% of the reserves from a new mine committed to long-term contracts (McDoulett 1980).

In a study done by the MITRE Corporation, 15 out of 22 utilities preferred a large portion of contract coal and a small portion of spot coal to meet their requirements (Lethi 1975). Four companies opted for totally contracted coal, one company preferred all spot, one preferred large percent spot/small percent contract, and one preferred half from subsidiaries/half from spot. Large utilities almost unanimously prefer contract coal over spot coal. This decision is based on reliable supply considerations, as well as price stability.

Although long-term contracting for coal purchases is a fairly recent phenomenon, it is now the main type of procurement used by utilities. From the utilities' viewpoint, contracting will secure coal supplies (possibly for the life of the plant) at a quality and price that will roughly reflect mining costs plus some return on the producer's investment. Provisions are usually included that allow for escalation or renegotiation based on mining costs and national price trends. Long-term, fixed-price contracts are virtually nonexistent.

Contracting coal is also favorable to producers since they can secure long-term sales and thereby protect their investment. Also, financing is obtained relatively easily if long-term contracts can be secured. Producers can also sell surplus coal in the spot market, which allows for optimal mine production levels.

The degree to which a utility is tied to a specific mine or mining company usually depends on the utility's location relative to other coal suppliers and alternative fuel sources. Contractual ties between minemouth utilities and their supplier are usually very strong since investments in special coal handling equipment may be needed. Furthermore, if the minemouth plant is in a

remote location, both supplier and consumer will have limited trade options. Eastern utilities, by contrast, have many supply options within a small geographic area.

The contract price of coal has traditionally been below the spot price, although in recent years spot prices have been suppressed by large stock-piles. The price gap between contract and spot prices is expected to narrow, mainly due to increasingly complex contracts that include many clauses permitting price increases.

Usually a large utility decides what fraction of coal requirements should be met by spot coal (if any) and whether to own a captive mine as opposed to contracting for coal. Although slightly lower costs may be realized through captive mine operations, some utilities noted greater control over supplies as a more important factor in choosing captive coal over contract coal. Contract mines provide assured supplies but offer little flexibility to load changes at the plant. As a result, utilities that contract for coal usually purchase a small percentage of spot coal to meet their total coal requirements. In times of peak demand, spot purchases will increase and at times of plant outages, spot purchases will drop off. A representative of a major coal-based utility has stated that his firm tries to purchase about 10% to 15% of its coal on the spot market to provide flexibility for dealing with short-term demand fluctuations (Lavallet 1980).

The majority of coal needed to bulk electric power production would be obtained from captive mines or long-term contractual arrangements. This would be especially true of plants located in Wyoming and Montana and using locally mined coal. Of the largest 25 coal mines in the U.S. in 1978, 13 are located in Wyoming and Montana (Keystone 1979). The large mines and limited transportation network in this area make spot purchasing impractical for the production of bulk electric power.

2.3.3 Coal Price Trends

It is believed that the coal industry will remain mostly competitive although some regional oligopolies may emerge temporarily as coal reserves are depleted. Improvement in transportation facilities (e.g., unit trains) has helped to dismantle regional market barriers and to keep the industry competitive.

Stable prices and reliable sources are incentives to utilities to operate captive mines. With utilities consuming over 75% of the coal mined in 1977, the incentive for commercial producers to operate efficiently and competitively is strong (Keystone 1979).

In the MITRE survey cited above, utility representatives outlined several elements that can affect spot and contract coal prices. Supply and demand seem to be the sole determinants of prices on the spot market. At times of over-supply, producers may sell their coal below production costs. At times of shortages, the producer will charge the maximum price that the market will bear. Many marginal mines operate only when spot prices are high.

Prices on the contract market tend to be a function of the following factors:

- prevailing market conditions at the time the contract is signed
- the type and complexity of escalation and renegotiation clauses in the contract
- coal quality and transportation costs.

Average contract prices are the best indicators of long-term prices, whereas the spot market reflects short-term market conditions. For example, in the Mountain region, which includes Wyoming and Montana, the spot price of coal was over three times the contract price of \$9.74/ton in June 1978 (Coal Week January 22, 1979). However, in April 1979, the spot price dipped below the contract price of \$9.75/ton for coal in that region (Coal Week April 9, 1979).

Although spot prices have essentially no upper limit, the lower limit is somewhat determined by the contract price. When spot prices fall below the contract price, utilities with contracts buy up the spot coal until prices rise again above the contract price. However, spot prices have remained below the contract price for as long as several months.

Historically, escalation of contract prices has mainly been determined by three factors (Gordon 1975):

- mining costs (including costs to comply with mining regulations)
- national price and wage trends
- mine productivity.

Mining costs and national prices and wages have been steadily increasing, while mine productivities have been decreasing (Mann and Heller 1979).

Table 2.6 lists the predominant methods used by electric utilities for coal price escalation. Although the factors listed above will probably remain the most important indicators of price escalation, the price adjustment clauses of new contracts are becoming more sophisticated and therefore a greater influence on contract prices.

Projections of net escalation of coal prices have been developed by EPRI for several supply and demand regions of the U.S. (EPRI 1982). These projections are specific to subbituminous coal from the western Northern Great Plains area, which encompasses Wyoming, Montana and northern Colorado. Prices, shown in Table 2.7, are in constant 1981 dollars and do not include general inflationary effects. Price per ton based on a reference coal with 9100 Btu/lb is also given. Projections for 2020 and 2030 are based on a 1.5% annual net escalation after 2010.

TABLE 2.6. Escalation Techniques Used by Electric Utilities in Long-Term Contracts

<u>Method</u>	<u>As % of Burn by Reporting Companies</u>	<u>As % of Industry Burn</u>
Predominantly by national trends	39.6	27.3
Predomonantly by mine costs	20.3	14.0
Predominantly by costs and national trends	18.6	12.8
Predominantly by national trends and mine productivity	17.6	12.1
Combination of national trends, mine costs and mine productivity	3.8	2.6
Total Reporting	100.0	68.8

TABLE 2.7. Projected Real (Net) Escalation of Western Northern Great Plains Coal Prices: 1985-2030^(a,b)

<u>Year</u>	<u>\$/10⁶ Btu</u>	<u>\$/Ton @ 9100 Btu/lb</u>
1981 ^(a)	0.63	11.47
1985	0.64	11.65
1990	0.65	11.83
1995	0.66	12.01
2000	0.73	13.29
2010	0.94	17.11
2020 ^(d)	1.09	19.84
2030 ^(d)	1.27	23.11

(a) EPRI 1982.

(b) Prices are FOB mine, constant 1981 dollars.

(c) Reference year price; slightly higher than actual 1981 coal prices due to depressed market conditions.

(d) Escalated beyond 2010 based on 1.5% annual real escalation suggested by EPRI for Western subbituminous coal.

Typical 1980 contract prices (FOB mine) for Wyoming coal range from \$6.75/ton^(a) to \$16.50/ton^(b) (Coal Week September 15, 1980). Based on the respective heat values of 8100 Btu/lb and 10,500 Btu/lb, the unit price of Wyoming coal ranges from \$0.42/10⁶ Btu to \$0.79/10⁶ Btu. The 1981 coal price of \$0.63/10⁶ Btu, given in Table 2.7, falls within the range of contract prices reported in Coal Week.

2.4 WESTERN COAL MINING

Federal regulations, Western mining methods, resource requirements and environmental effects of Western surface mining of coal are reviewed in this section.

(a) 8100 Btu/lb, 0.5% sulfur, 6.0% ash.

(b) 10,500 Btu/lb, 0.6% sulfur, 8.5% ash.

2.4.1 Federal Surface Mining Regulations

The Surface Mining Control and Reclamation Act of 1977 is the major piece of federal legislation affecting the surface mining of coal by specifying areas unsuitable for surface mining and by establishing requirements for reclamation. The Office of Surface Mining (OSM) is the primary regulatory agency responsible for receiving mining plans and for insuring that rules and regulations established under the Act and concerning land reclamation are enforced. The Act applies to all coal mining operations, establishing a nationwide program to minimize adverse effects from surface mining operations, assuring that the rights of land owners are protected, and assuring that proper reclamation procedures are undertaken as required to reclaim surface areas. Provisions of the Act can be implemented by state agencies under OSM approval. Most states are currently revising their plans to comply with the Act. Wyoming, however, does have an approved plan. State plans may contain land use and environmental controls that are more stringent than the federal guidelines. An approved state plan must include environmental assessment procedures, a reclamation plan and requirements for performance bonds. The permitting process must address such topics as irreparable land degradation, water pollution, disruption of cultural resources, and soil surveys of potential prime farm land (Little and Capehart 1980).

The Surface Mining Control and Reclamation Act also establishes stringent performance standards with which all operators shall comply where any element of the operation is regulated by a state. Two sets of performance standards apply to surface mining operations: general performance standards and special performance standards. These standards are briefly discussed below.

General Performance Standards (30 CFR Part 715)

The major purpose of the general performance standards is to ensure that all surface mining activities are conducted in a manner that preserves and enhances environmental values. The standards are concerned with nine major types of activities:

- postmining use of land
- protection of hydrologic system
- topsoil handling

- use of dams
- use of explosives
- disposal of spoil and waste materials
- backfilling and grading
- revegetation
- use of signs and markers.

Postmining Use of Land. In general, disturbed areas must be restored to conditions that are capable of supporting premining use. Postmining use for land previously mined and not reclaimed is to be judged on the basis of the best use that can be achieved and that is compatible with the area. Land improperly reclaimed following earlier mining activities is to be restored to the land use of nearby properly managed lands.

Operators are required to include an analysis of the postmining land use in the initial application for a mining permit and the use must be given approval prior to starting mining operations. To choose to implement a land use differing from premining use, the operator must perform a feasibility study and show that the new use plans will not delay reclamation work. Alternative use plans must be compatible with adjacent land use and with local, state or federal land use plans. To convert the land to agricultural use, the operator must commit funds to crop management.

Protection of the Hydrologic System. Changes in water quality and quantity caused by mining operations must be minimized. Preventive mining and reclamation techniques are preferred over water treatment facilities. Discharges must meet applicable laws and OSM effluent limitations. Stream channel diversions must be constructed with the best available technology. Fish, wildlife and vegetation of value must be protected. Streams ordinarily will have a protected 100-ft buffer zone. Sedimentation ponds, water monitoring and reporting, burial for acid and toxic material, and replacement of altered water supplies are required. Discharges into underground mines are prohibited.

Topsoil Handling. The topsoil must be segregated, stockpiled and protected from erosion, with soil horizons treated separately. Redistributed soil must be uniform, with erosion minimized, and must support vegetation.

Dams. Waste may generally not be used in new or existing dams. Detailed dam construction and inspection requirements are specified.

Use of Explosives. Blasting that uses more than the equivalent of 5 lb of TNT must be preceded by locally published public notice of the blasting schedule. All state and federal explosive use laws apply.

Disposal of Spoil and Waste Materials. Spoil must be disposed of within a permit area and transported in a controlled manner. Coal processing wastes cannot be dumped in valley or head-of-hollow fills.

Backfilling and Grading. Spoil must be transported, backfilled, compacted and graded. Final graded slopes cannot exceed approximate premining slopes. Some exemptions are available.

Revegetation. Native vegetative cover must be re-established as soon as land is restored. Mulching is required and methods of revegetating are outlined for various postmining uses.

Signs and Markers. Signs and markers must be standardized, durable and easily seen. Blasting signs are always required. Buffer zones must be marked.

Special Performance Standards (30 CFR 716)

All surface mining and reclamation operations subject to the special performance standards shall also comply with the requirements of the general performance standards unless otherwise specifically exempted. The special performance standards apply to the following special circumstances:

- steep-slope mining
- mountaintop removal
- special bituminous coal mines
- anthracite surface coal mining
- anthracite surface mining in Alaska
- surface coal mining on prime farmland.

Steep-Slope Mining. Mining on slopes of more than 20° is subject to special standards unless exempted. Spoil is not allowed to be placed downslope from mining operations. Highwalls must be regraded, and excess spoil and woody materials must be disposed of properly.

Mountaintop Removal. Special standards are listed for mountaintop mining operations. Postmining land use plans must be accompanied by a feasibility study. Permits are reviewed every three years.

Special Bituminous Coal Mines. Bituminous coal surface mines located in Wyoming must be mined according to a special set of criteria. These criteria focus on the excavation of the mine pit, slope specifications and postmining land uses.

Anthracite Surface Coal Mining. Anthracite surface coal mining and reclamation operations in states maintaining approved environmental protection standards shall be regulated by the state. Only a few isolated deposits of anthracite exist in the West.

Surface Coal Mining in Alaska. Surface coal mining operations in Alaska must meet the minimum requirements of special performance standards. These standards may be modified to insure continued operation of the mine. Petitions to modify the standards must comply with certain requirements. The general public may challenge a decision to modify the standards.

Surface Coal Mining on Prime Farmland. Prime farmland, as defined by Department of Agriculture standards, may be mined only under stringent rules, including removal of all soil horizons with replacement required.

States will assume primary responsibility for regulating mining and reclamation operations on nonfederal lands after approval of the state enforcement program by the Secretary of Interior. Standards must be at least as stringent as those in these federal regulations. If no state plan is approved, OSM will enforce the federal regulations until a state plan can be implemented. States may enter into cooperative agreements with the Department of Interior to enforce standards at least as stringent as federal standards on mining federal lands.

Other Regulations

The following are additional federal environmental legislation potentially affecting the surface mining of coal:

- Mine Safety and Health Act of 1977 - sets operational standards for coal mines and requires training for miners.
- Occupational Safety and Health Act - regulates health and safety conditions in the industry.
- Federal Land Policy and Management Act; Minerals Leasing Act; and Coal Leasing Amendments Act of 1976 - establish procedures to control the leasing of federal lands for coal mining.
- Wilderness Act - severely limits coal mining in designated wilderness areas.
- Wild and Scenic Rivers Act - prohibits coal operations from reducing the quality of designated scenic rivers and wildlife habitats.
- Clear Air Act - sets emission limits for particulates from mining operations and establishes ambient air-quality standards, and prevention of significant deterioration requirements.
- Clear Water Act - requires an NPDES permit for coal mine drainage and establishes effluent guidelines and standards for coal mining.
- Resource Conservation and Recovery Act - regulates solid waste disposal from coal mining operations.
- National Environmental Policy Act - requires preparation of an environmental assessment or impact statement for major federal actions potentially having a significant effect on the human environment.

2.4.2 Western Mining Methods

Two main types of surface mining are used in Wyoming and Montana: area strip mining and open pit mining. Both methods use a wide variety of equipment, depending on the physical characteristics of the terrain. For both types of mining methods, reclamation is required.

Area Strip Mining

Area strip mining (Figure 2.3) consists of eight unit operations. Each operation generally corresponds to the use of a particular machine.

AREA-MINING METHOD WITH STRIPPING SHOVEL

2.27

FIGURE 2.3. Area Strip Mining (Skelly and Loy 1975)

Clearing and Grubbing. The removal of trees, bushes, stumps or any large plant life takes place in this operation. Because the Northern Great Plains region is characterized by farmland, pastureland and semiarid range, very little clearing is required. Clearing is accomplished by bulldozers.

Topsoil Removal. When possible, topsoil is removed by pan scrapers prior to overburden removal and placed on previously mined, regraded land in one continuous operation. When this is not possible, topsoil is removed and stored in stockpiles until regrading operations commence.

Overburden Preparation. Overburden preparation usually involves drilling and blasting to break up overlying strata. This procedure is often unnecessary in the Northern Great Plains region due to the unconsolidated nature of the overburden.

Overburden Removal. The removal of overburden is usually accomplished by pan scrapers in conjunction with draglines or power shovels. Removal begins with an initial "box cut." Removal continues in adjacent cuts with the overburden being placed in spoil piles. When the full width of the planned cut is reached, parallel cuts commence with overburden being placed in previous cuts where coal has been removed in a continuous operation (Figure 2.3).

Coal Loading. Coal loading is accomplished by a variety of methods and machines, depending on the characteristics of the mine and the coal. Some blasting of the coal before loading may be necessary, depending on the coal seam. Also, for some thick seams, a form of removal known as "benching" is used, in which coal is removed in steps. The equipment used for coal loading includes front-end loaders and loading shovels.

Coal Haulage. Coal hauling from mine to preparation facility is accomplished by off-highway vehicles. In some cases, conveyors provide supplemental movement. Usually, each mine has its own preparation facility. Therefore, hauling is accomplished by equipment suitable for the distance from mine to preparation plant and matches their capacities. Capacities of off-highway vehicles range from 35 to 200 tons (Skelly and Loy 1975).

Regrading. Regrading involves the replacement of all overburden spoils to the mine. Regrading is usually accomplished by dozers or scrapers that return the land to its approximate original contour. Due to thin overburdens and thick coal seams that are common in Wyoming and Montana, some depression in the original topography will occur.

Revegetation. Much of Wyoming and Montana has a semiarid climate. As a result, revegetation can be extremely difficult. Erosion from the wind can be severe and provisions for moisture retention (in the form of gouging, dozer basins, snow fences, mulches, etc.) must be made. Since extensive strip mining is relatively new to this region, new methods of seeding and irrigation are being tried.

Open Pit Mining

Open pit mining can be applied to either dipping seams or thick seams. Dipping seams are coal seams that extend steeply into the ground. When mining multiple dipping seams by the open pit mining method, overburden is often cast both above and below the strip cut. The overburden placed below the cut partially covers the previous highwall and the overburden placed above the cut is stored above the current highwall. After the coal has been removed, the mine is regraded into an approximation of the land's original contour. Other unit operations in open pit mining of dipping seams are similar to area mining.

Open pit mining of thick seams is a technique that is unique to the Northern Great Plains region (Figure 2.4). This method is used when overburden is very thin and coal seams are thick. In this situation, proper coal removal and loading become more important than overburden removal. Mining of thick seams begins with the removal of overburden to adjacent land or to a storage area by shovel loading and truck haulage rather than draglines. The coal is then removed in a benching operation where several small highwalls will be formed in the shape of steps, as opposed to one large highwall. As mining proceeds and coal is removed, newly stripped overburden is replaced to the pit floor. Since seams in the West may exceed 70 ft in thickness, there is usually a significant change of the original contour after regrading.

OPEN PIT MINING CONCEPT

FIGURE 2.4. Open Pit Mining (Skelly and Loy 1975)

Most of the unit operations in open pit mining are similar to those of area strip mining. One exception is that when mining thick seams, overburden may be hauled to a storage area instead of being placed on adjacent land.

Reclamation Costs

Reclamation includes topsoil removal and replacement, regrading, and revegetation. Proper reclamation appears expensive. Estimates of \$2000 to \$5000/acre have been cited by many companies (Carlson et al. 1977). Because many of the Northern Great Plains coal seams are thick, per-ton reclamation costs are low and reclamation does not add significantly to the cost of coal. A reclamation cost of \$3000/acre only adds 3¢/ton to the cost of coal in a 50-ft seam (Carlson et al. 1977). This figure will vary with the thickness of the seam. However with the extremely low stripping ratios found in Wyoming and Montana and thick seams encountered in the Powder River Basin, reclamation costs for most mines in this area are expected to be low.

2.4.3 Resource Requirements

The principal resources required in Western surface coal mining are auxiliary energy, manpower, land, and water. Other resource requirements include tires for mobile equipment and steel for machinery. A considerable regional and site variation exists in the quantity of a given resource required, depending on stripping ratios, mining methods, seam thickness, terrain features, water availability and types of equipment used.

Auxiliary Energy

Auxiliary energy requirements for surface coal mining consist of diesel fuel and electric power. Diesel fuel and gasoline account for approximately two thirds of the total energy expended in surface mining (Jarmen et al. 1979).

The mobile equipment used in surface mines (e.g., dozers, trucks, loaders) runs primarily on diesel fuel. The estimated diesel fuel consumption for extraction and loading equipment is 0.1 gal/ton of coal extracted (Hittman 1974). Trucks that haul the coal to a preparation plant or transport facility (est 1.5 mi) consume an estimated 0.02 gallons of diesel fuel per ton (Hittman 1974).

Although Western coal usually does not require much preparation, some breaking and sizing is performed at the mine. For this operation, an estimated 0.04 gallons of fuel oil per ton is consumed. Therefore, for each tone of coal extracted, 0.16 gallons of fuel is used (Hittman 1974). This figure, however, is a very rough estimate that may vary significantly for a specific mine.

Electricity is used in both extraction and preparation processes. Draglines and large, immobile equipment are typically electrically powered. In addition, electricity is used for lighting of the mine and for field offices. An estimated 2 kWh/ton are used for extraction (Hittman 1974).

Breaking and sizing plants also use electric power. An estimated 3 kWh/ton are used for breaking and sizing. This brings total electric power use in mining and preparation operations to 5 kWh/ton (Hittman 1974). Another study estimated 2 kWh/ton of coal extracted for surface mines in the Powder River Basin (U.S. DOE 1980).

Manpower

Manpower requirements for construction and operation of a Western surface coal mine includes nonmanual, technical and nontechnical, and manual personnel. Total manpower requirements are estimated at 0.064 man-years/ 10^3 ton coal extraction for construction and operation (Bechtel 1978).

Land

Two types of land are required for a surface mine: 1) the active land area required by the stripping overburden and the actual mining of coal, and 2) the fixed land area required for the permanent facilities at the mine. The amount of land disturbed or required per ton of coal removed depends on the thickness of the coal seam. The fixed and incremental land area for Western surface mining of coal is estimated at 0.0073 acres and 0.033 acres/ 10^3 ton of coal, respectively, for a 30-ft seam (U.S. DOE 1980).

To determine the total acreage of land disturbed by a mining operation, the thickness and density of a coal seam must be known. Table 2.8 shows the number of acres disturbed by strip mining for a given seam thickness. The volume of coal mined that was used for Table 2.8 is equal to the amount of coal consumed by a 1000 MW plant for a 30-year life at 65% capacity factor (97 million tons). The total land disturbed by mining ranges from 8.6 sq mi for a

TABLE 2.8. Land Affected by Surface Mining^(a,b)

	Seam Thickness (feet)			
	10	30	50	70
Land Disturbed ^(c) (Acres)	5498	1833	1100	785
Square Miles	8.6	2.9	1.7	1.2

(a) Based on Hittman (1974).

(b) Assumes a coal density of 81 lb/ft³.

(c) Based on the coal used by a 1000 MW coal-fired power plant in a 30-yr life. Assumptions:

- 9000 Btu/lb subbituminous coal
- 65% capacity factor
- 9700 Btu/kWh heat rate
- 5% rejection of mined coal.

10 ft seam to 1.2 sq mi for a 70-ft seam. Although a much smaller area is potentially affected by thick-seam mining, the topographic impacts are proportionally much more severe.

Water

The two major uses of water in mining operations are for dust control and revegetation. Due to the semiarid climate of Wyoming and Montana, severe dust problems can occur in normal mining operations. Therefore, water trucks are used to control dust, mainly on the haul roads. Estimates of water consumption range from 5 to 12 gallons per ton of coal extracted (Gold et al. 1977 and Carlson et al. 1977).

Revegetation of reclaimed land also requires water. Water consumption for revegetation ranges from 0.5 to 4 acre-ft per acre of reclaimed land (Western States Water Council 1974). This value translates as 57 to 454 gallons of water per ton coal extracted, assuming the active land is reclaimed.

Since water is a scarce resource in many areas of Wyoming and Montana, it could be a constraining factor in large-scale coal extraction. Additional discussion of the use of water in coal extraction is provided by Rogers (1980).

Other Resource Requirements

Other resource requirements include rubber for vehicle tires and steel for vehicles and machinery. Tire cost can account for 20 to 60% of equipment maintenance costs, but this depends on speed, road condition, loading and tire construction and size. Estimates of tire life for mining and hauling equipment ranges from 32,000 to 42,000 miles (Gessel 1978). The amount of steel required for machinery is highly variable, depending on the specific mine layout.

2.4.4 Environmental Effects

The environmental effects of surface mining coal, including land impacts, atmospheric emissions, wastewater discharge, and accident rates, are summarized in this section. The magnitude of these effects depends on the mining method employed and site-specific conditions. Impacts on land are by far the most severe.

Land Impacts

Surface mining of coal results in profound impacts to the land being mined. Premining uses of the land are terminated and existing ecological, cultural and (smaller) hydrologic features of the landscape are eradicated by mining operations. Operators are now required to reclaim affected land to approximate original contour and use, allowing in many cases eventual restoration of premining ecosystems and land use. Many years, however, may be required to restore premining conditions, delaying resumption of land uses, such as grazing, that are strongly dependent upon natural ecosystems.

The predominant land use in Western surface mining areas is grazing of sheep and cattle. In fact, 97% of Western areas disturbed by surface coal mining were used for grazing prior to mining; the remaining 3% was cropland or hayland, and wildlife habitat was negligible (Cook 1979). Some concern naturally exists over the compatibility of coal mining, on a projected large scale, and the existing land use.

Probably the most severe problem in semiarid regions is revegetation of the mined area after regrading. Topsoil must be stored during stripping operations and replaced after regrading of the terrain. During revegetation approximately 0.5 to 4 acre-ft of water is required to establish plant growth for each acre of disturbed land (Western States Water Council 1974). However, even if revegetation is successful, many reclaimed areas require fencing for several years since new grasses and legumes are often destroyed by grazing (Carlson 1977). Some estimate the time required for the land to completely return to its original ecological balance to be as long as 100 years (Hittman 1974).

Another problem associated with reclamation is the radical change in the natural contour of the land that can occur when mining thick seams (some of the coal seams found in the West are over 70 ft thick). When reclaiming the land, not enough overburden exists to return the land to its original contour. This can result in a significant depression in the landscape, and steep slopes, despite attempts to regrade the land into gently rolling terrain. Steep slopes can produce erosion problems from both wind and rainfall if not revegetated

properly. Therefore, revegetation becomes very important under these conditions. When revegetation is impractical, alternate uses, such as the forming of small lakes, are sought.

Aesthetic impacts of surface mining operations may be significant. Although the viewing population is generally low in the region considered by this study, the presence of moderate topographic relief, especially in Wyoming and southeastern Montana, and the general absence of trees will readily expose mining operations to viewers.

Atmospheric Emissions

Potential sources of airborne emissions from surface mining activities include dust and other materials emitted during blasting and materials handling operations, major combustion products released by diesel equipment used in mining operations (i.e., extraction and hauling), and wind-blown dusts from mines and waste piles. The emissions from stripping, loading and haulage equipment are relatively minor and easily quantified. Table 2.9 shows the approximate emissions from mining equipment, based on tons of coal mined.

TABLE 2.9. Air Emissions from Coal Mining Equipment^(a)
(tons/ton of coal extracted)

	Particulates	NO _x	SO _x	Hydrocarbons	CO	Aldehydes
Extraction Equipment	7.2×10^{-7}	1.8×10^{-5}	1.3×10^{-6}	1.8×10^{-6}	1.1×10^{-5}	2.9×10^{-7}
Hauling Equipment ^(b)	1.6×10^{-7}	4.5×10^{-6}	3.3×10^{-7}	4.5×10^{-7}	3.1×10^{-6}	3.7×10^{-8}
TOTAL	8.8×10^{-7}	2.3×10^{-5}	1.6×10^{-6}	2.3×10^{-6}	1.4×10^{-5}	3.3×10^{-7}

(a) (Hittman 1974).

(b) Estimated haul distance is 1.5 mi/load.

Fugitive dust emissions from blasting and materials handling operations and from mines and waste piles from wind erosion is estimated to be 1.4×10^{-5} tons for each ton of coal extracted. This value was calculated by Hittman Associates (1974) on a time-average basis assuming a 6.5×10^{-5} acre-yr/ton

disturbance and a 428 lb/acre-yr erosion rate. These estimates, however, are very uncertain. The West has more potential for fugitive dust emissions than the East due to the drier climate and slower revegetation cycles (U.S. DOI 1979).

Wastewater Discharge

Contamination of groundwater and surface water has long been a problem of coal mining operations. Although Western surface mines do not have the problem of acid mine drainage common to Eastern underground mines, high levels of suspended solids and some dissolved solids may pollute local groundwater that seeps into the mine.

Estimates of groundwater contamination under uncontrolled conditions are given in Table 2.10. Although high concentration of dissolved and suspended solids may be unavoidable, the runoff from the waste piles can be collected in a settling basin. This water can then be used to control dust on haul roads since the quality of the water is unimportant for this use. In this case very little, if any, contamination of local surface water occurs (Hittman 1974). Again, the estimates in Table 2.10 are highly uncertain. The main sources of

TABLE 2.10. Water Effluents in Surface Mining Operations^(a)

<u>Suspended Solids</u>	<u>Tons/Ton of Coal Extracted</u>
Coal Fines	3.0×10^{-5}
Sediment	3.7×10^{-4}
Total Suspended Solids	4.0×10^{-4}
<u>Dissolved Solids</u>	
K and Na	3.8×10^{-6}
Fe	4.6×10^{-7}
Sulfate	7.5×10^{-6}
Ca	1.7×10^{-6}
Mg	2.3×10^{-6}
Total Dissolved Solids	1.6×10^{-5}

(a) Hittman 1974.

wastewater discharge from surface mining activities are refuse pile runoff and mine drainage. In the West, the discharge is typically alkaline (U.S. DOE 1980). When a mine operator employs methods of wastewater treatment, additional solid wastes are produced. However, these wastes are generally returned to the excavated mine.

Groundwater effects from surface mining are not fully understood. Many coal seams are in aquifers, which may be altered by mining operations. Rerouting of groundwater flows and lowering of the local water table have been noted at some mines.

Accident Rates

The accident fatality rate for underground mining of coal is higher than any other occupation examined by the National Safety Council (ANL 1977). However, injuries, deaths and man hours lost due to accidents are considerably lower for surface mining. Accidents from surface mining could result from highwall collapse, heavy equipment haulage, improper use of explosives, mishandling of tools, electrocution, fires, and falling. Fatalities, injuries and man-days lost due to Western coal surface mining are estimated at 1.2×10^{-7} , 5.6×10^{-6} , and 1.7×10^{-3} per ton of coal extracted, respectively (Bliss et al. 1977).

2.5 SUMMARY

Coal production is expected to increase annually in both Wyoming and Montana as the demand for low sulfur coal increases. However, to satisfy the coal requirements for a 10,000 MW electricity production scenario, coal production will have to increase significantly. The combined output of the four largest coal mines in the U.S. in 1977 is approximately equal to the annual coal requirements of a 10,000 MW production scenario (42 million tons).

Coals from Wyoming and Montana have some favorable and some unfavorable characteristics. Favorable characteristics include low sulfur, ash, and sodium content. Unfavorable characteristics include high moisture content, low grindability index, and moderate heat value. Due to low cost and environmental regulations that limit emissions of sulfur oxides, Northern Great Plains coal is favored by many utilities.

Utilities may either buy coal from producers or establish their own mining operation (captive production). Coal bought from producers may be contracted or bought on the "spot" market. Contract coal prices usually reflect mining costs plus a return on investment, whereas spot coal prices are highly influenced by market supply and demand. Elements that affect the long-term price of coal include increases in mining cost, national price and wage trends, and mine productivity.

Western mining is accomplished predominately by strip mining. Strip mining techniques used in Wyoming and Montana include area mining and open pit mining. The most severe environmental problems from Western surface mining include disruption of the land contour and natural vegetation and wildlife populations of the land. Disruption of groundwater hydrology can also be significant in some cases. Wind-blown dust from mines is the greatest air pollution problem, whereas high levels of suspended solids appear to be the greatest water pollution problem. It is optimistic to think that environmental harm from surface mining can be eliminated. However, with proper controls such as regrading, topsoil replacement, revegetation, dust suppression, and settling basins, the environmental effects can be minimized.

Socioeconomic consequences of Western surface mining, including preemption of traditional land uses and effects of population influx, can also be severe; discussion of these, however, is beyond the scope of this report. Federal regulations concerning strip mining set general and special performance standards. These standards establish specific procedures for extraction and reclamation. Although some standards appear strict and costly, reclamation costs for many seams in the West are quite low because of a low overburden-to-seam thickness ratio.

Resources consumed in mining activities include water, diesel fuel, tires and electric power. Of these, water may be a critical resource, depending on location.

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3.0 WESTERN COAL TRANSPORTATION

Technical and economic characteristics, first-order environmental effects, and significant material requirements of long-distance transportation of large quantities of western coal are discussed in this chapter. The major modes of coal transportation currently include rail, slurry pipeline, barge, truck, and conveyor systems. Because of distance and geography, unit train and slurry pipeline are the most feasible methods for transporting large quantities of Northern Great Plains coal to Midwest and West Coast load centers.

This chapter is divided into three sections:

- coal movement
- rail transport
- slurry pipeline transport.

The coal movement section contains an overview of coal transportation alternatives including rail, slurry pipeline, barge, truck, and conveyor. The characteristics of rail transport and slurry pipeline transport are discussed in some detail in the second and third sections. Within each of these two sections are subsections discussing technical characteristics, energy and major material requirements, costs, and environmental effects.

3.1 COAL MOVEMENT

Coal must be moved from the mine to its point of consumption. Long haul transportation of coal is generally accomplished using trains, slurry pipelines, and barges, supplemented by trucks and conveyors for shorter distances.

After mining, coal must be moved to either a processing facility or to the place where it is to be consumed. Transportation efficiency is very important in the coal fuel cycle because of the weight and volume of material that must be moved. A 1000 MWe coal-fired power plant requires about 3.5 million tons of Western coal per year (9600 tons per day), which is roughly equivalent to three million cubic yards. The cost of transportation can amount to 50% or more of the cost of delivered fuel. In 1977 domestic coal deliveries to electric utilities reached 474.8 million tons, representing 77% of the coal consumed that year (Keystone 1978).

An origin-destination map of domestic coal movements in 1976 is shown in Figure 3.1. Two types of coal movement are shown; interregional transport is represented by arrows drawn from supply region centers to the boundaries of demand regions, and intraregional coal transport is indicated by semicircles. The coal volumes transported are represented by the scale size of the respective indicators.

Over the long distances considered in this study large tonnages of coal are transported by rail or slurry pipelines. Coal transportation by barge is competitive with rail and slurry pipelines where navigable waterways exist. However, due to the lack of navigable waterways in the Northern Great Plains area, barge transportation was not considered for this study. Certain Midwest load centers, however, may be economically served by combined rail-barge routes. These options were considered to be beyond the scope of this study.

3.1.1 Rail Movement

Rail is the primary method for coal transportation in the U.S. Coal moved solely by rail totaled over 323 million tons (54% of total) in 1978 (Table 3.1). In addition, barge coal movements via the Great Lakes, rivers, and tidewater are usually supplemented by rail movement. The average rail haul for coal in 1975 was 300 miles; over half of the coal produced in a region was consumed in the same region. The U.S. rail system and regional coal movements by rail are shown in Figures 3.2 and 3.3.

3.1.2 Slurry Pipelines

Two coal slurry pipelines have been built in this country. One is operating; one was shut down by rail competition after several years of operating; and several more are being designed or planned (Figure 3.4). The Black Mesa pipelines, the only operating pipeline in the U.S., carries 4.8 million tons of coal annually from the Kayenta coal mine in Arizona to the Mohave generating station in southern Nevada, 275 miles away. Characteristics of existing and planned coal slurry pipelines are presented in Table 3.2.

FIGURE 3.1. Domestic Coal Movements Between Geographic Division - 1976
(DeSteele et al. 1978)

TABLE 3.1. Coal Transportation by Mode
in United States - 1978^(a)

	<u>1000 tons</u>	<u>Percent</u>
Rail ^(b)	323,500	54
Barge ^(c)	116,289	19
River and Ex-River	(96,301)	(16)
Great Lakes	(16,175)	(3)
Tidewater	(3,813)	(1)
Truck ^(d)	93,530	16
Tramway, private rail, conveyor and pipeline	<u>65,893</u>	<u>11</u>
Total	599,212	100

(a) DOE/EIA 1979.

(b) Some rail shipments are supplemented by truck.

(c) Shipments by barge are usually supplemented by rail transportation, which is not included in the rail tonnage; percentages by water route do not add due to rounding.

(d) Shipments by truck only.

3.1.3 Barge Movement

Barges carry about 12% of the raw coal shipped in the U.S. Barges move on the domestic waterway system, which consists of 25,500 miles of inland channels plus the Great Lakes and intercoastal waterways (Figure 3.5). The average distance coal is shipped on water is 350 miles. Because most coal mines are not close to navigable waters, the coal must be moved to the barge loading facility either by truck or train. Amounts and directions of coal shipped on inland systems for 1976 are indicated in Figure 3.6.

3.1.4 Truck Movement

In 1978 approximately 16% of the total coal shipments were made by truck (DOE/EIA 1979). Truck transportation is the dominant method of shipping coal over short distances; however, it is not significant in cross-country movement

FIGURE 3.2. U.S. Rail System Showing Wyoming-Montana Coal Fields and Western and Midwestern Load Centers

FIGURE 3.3. Coal Movement by Railroad - 1978
(DeSteele et al. 1978)

FIGURE 3.4. Existing and Planned Coal Slurry Pipelines in the United States

of coal.^(a) Trucks are frequently employed for collection operations at mines to deliver to minemouth power stations or to railheads or waterways for transshipment. Both (very large) off-road vehicles and on-road vehicles are used. Small producers and small consumers are often served by truck. While useful for coal collection from dispersed sources and moving headwalls, trucks are not energy efficient in moving large quantities of bulk materials over long distances and contribute significantly to the deterioration of public roads.

3.1.5 Conveyor Movement

In 1973 about 48 million tons of coal were transported by conveyor (Jimison et al. 1976). The conveyor is especially useful for transporting coal across mountainous or rough terrain not suitable for roads but is generally

(a) The average truckload haul of coal is 50 to 75 miles (Jimison et al. 1976).

TABLE 3.2. Existing and Planned Coal Slurry Pipelines
in the United States^(a)

Stage	Pipeline Location	Pipeline System/Developer	Pipeline Length (miles)	Pipe Diameter (inches)	Capacity (10 ⁶ tons/yr dry)	Initial Operation
Constructed	Ohio	Consolidation Coal Co.	108	10	1.3	1957
Constructed	Arizona to Nevada	Black Mesa Pipeline Co.	173	18	4.8	1970
Designed	Utah to Nevada	Nevada Power	180	24	10	1983 ^(b)
Designed	Wyoming to Arkansas	Energy Transportation Systems, Inc.	1036	38	25	--
Planned	New Mexico to Arizona	Salt River System	180	16	4	--
Planned	Colorado to Texas	Houston Natural Gas Co.	1100	28	15	--
Planned	Montana to Texas	Wytex	1260	42	30	--
Planned	Wyoming to Oregon	Northwest Pipeline Gulf Interstate	800	24	10	--

(a) Clark 1979.

(b) Estimated startup date.

FIGURE 3.5. Navigable Inland Waterways of the United States

FIGURE 3.6. Coal Movement by River - 1976
(DeSteele et al. 1978)

limited to short distances.^(a) Although conveyors are commonly used at mines, only large mines can justify the capital investment required for a long-distance belt conveyor.

An example of long-distance conveyor use is found at the Kayenta mine in Arizona. The northern and eastern sides of the 3200-square-mile Black Mesa are almost sheer escarpments of about 1800 feet and a railroad cannot be easily routed to the mine. A six and one-half-mile, three-flight conveyor transfers 1400 tons of coal per hour from the mine to four silos on the valley floor 2000 feet below. An 80-car electric unit train then hauls the coal 80 miles to the Navajo power plant in Page, Arizona.^(b)

3.2 RAIL TRANSPORT

Rail movement of coal may be accomplished via single carload, multiple carloads, trainload volume or unit train. Single carload operations, used for shipment of small quantities of coal to or from dispersed locations, involve movement of individual cars from the mine via freight trains to a nearby terminal or division point. Freight trains then move the coal to the terminal or division point nearest the recipient. Here the cars are moved by freight train to the consignee. The rail cars used are not dedicated and following unloading are returned to a car pool. Because of complex switching and handling requirements and irregular scheduling, carload movement is generally the most expensive method of moving freight.

Multiple carload operations are handled similarly to single carload movements, but several cars are moved together from the same origin to the same distribution with consequent reduction in per-car switching and handling requirements. Because of cost savings resulting from reduced car handling incentive freight rates are generally applicable to multiple carload movements.

Trainload volume service may be used where the volume of freight movement from a given origin to a given destination warrants use of a dedicated train

(a) A conveyor's range is usually between 1 and 10 miles.

(b) At present, the capacity of the Kayenta conveyor is not adequate to serve the unit train and is supplemented by truck transport.

for the run. Trainload volume service draws upon pool railcars and locomotives. When the shipment is ready, a complete train is assembled at a terminal or division point near the origin. This train is dispatched to the origin and loaded and proceeds directly to the destination. The locomotives and caboose are released for alternative service and the railcars are returned to a nearby pool following unloading. Unlike unit train operations, scheduling is irregular and equipment is shared with other operations. Because of more intensive equipment use and reduced yard operation, freight rates for trainload volume service are normally less than for multiple car shipments but greater than for unit train service.

Unit trains are single purpose, dedicated, integrated trains used for scheduled shipment of bulk commodities between a fixed origin and destination. When used for coal transport, they run directly from mine to power plant, are loaded and unloaded mechanically for rapid turnaround and are returned to the origin empty. Unit trains require only a small crew. In 1977 Burlington Northern, one of the largest railroads moving Western coal, moved 88% of their 53.5-million-ton coal volume by unit train (Keystone 1978). Unit train transportation has become a significant advancement in coal movement by rail and depends upon close cooperation among mining companies, railroads, and electric utilities.

A typical coal unit train consists of five 3000 hp locomotives pulling 100 open hopper cars with carrying capacities of 100 tons each. Train speed varies considerably depending on track condition, but 20 to 50 mph is a common range. Roughly twelve such train loads per day are required to deliver 42 million tons of coal per year, the amount required to fuel a 10-GWe generating complex at a 90% load factor.

Large unit trains operate 300 to 340 days per year at an average speed of 22 miles per hour for Western routes (Coal-By-Wire 1979; OTA 1978a). This high usage depends on deployment of up to 20% spare locomotives and 10% spare coal cars when needed. the intensive use of dedicated rolling stock makes unit trains the most economically efficient manner of transporting large quantities of coal by rail.

Successful operation of unit trains requires the train to spend as much time as possible on the road. To do this, high-rate loading and unloading facilities, as well as significant storage capability, must be installed to minimize turnaround time. Despite the heavy investment burden that results from the equipment requirements, the increased costs due to this additional equipment are less than those incurred in the movement of similar but fragmented tonnages picked up and delivered to and from several locations in multiple car lots.

Unit trains can be routed to bypass switching yards to avoid the cost and delays involved. With one cargo, one origin, one destination, rapid loading and unloading, and no yard time or train makeup time, unit trains may average over 800 miles per day. Conventional freight trains average 60 miles per day, although distances are highly dependent on track conditions.

3.2.1 Technology Description

A complete unit train coal-delivery system includes three major components:

- rolling stock
- track and roadbed
- coal-handling terminals.

Rolling Stock

Rolling stock refers to the unit train's components: locomotives, coal cars, and caboose. A typical unit train may consist of 5 locomotives, 100 coal cars and 1 caboose.

Locomotives used in long-distance unit train service usually weigh about 185 tons, are about 67 feet long and are powered by 3000 to 3600 hp motors. These locomotives use either a two-stroke or four-stroke cycle, turbocharged diesel engine. A loaded 100-car unit coal train using five 3600 hp locomotives would result in a hp/ton ratio of about 1.25.

Coal cars are simple box-shaped cars with open tops. The capacity of these cars can range from 50 to 140 tons, but the typical capacity rarely exceeds 100 tons. The typical coal car weighs 31 tons, is 50 feet in length, and has a 100-ton capacity.

Coal cars come in two types: the gondola car and the hopper car. The main difference between the two types is in the coal discharging method. Bottom-dump hopper cars discharge coal through hatches in the bottom of the car. These hatches are opened manually or automatically as the train passes over a trestle above the coal pile. The lower portion of bottom-dump cars has sloped sides so that the coal flows out easily (Figure 3.7). Gondola cars, having open tops and solid bottoms, require rotary dumping in which cars are positioned in a rotary dumper and are inverted and dumped while remaining coupled to the train (Figure 3.8). Coal cars used in rotary-dump operations are equipped with rotary couplers on one end so that dumping may take place while the train is coupled. Hopper cars may also be used for rotary dumping if they have a rotary coupler.

In addition to locomotives and coal cars, unit trains have a single caboose coupled at the rear of the train. Unit trains use standard railroad cabooses.

The expected life of rolling stock is about 15 to 20 years with proper maintenance. Cabooses generally last about 25 years. However, due to the intensive use of the rolling stock in dedicated unit train service, a 15-year life is more likely.

To determine the rolling stock required to transport a given volume of coal over a given distance, the tonnage to be moved, the tonnage per train load and round trips per year of each train must be known.

$$UT_i = \frac{TPY_i}{(CAPT)(RTY_i)} \quad (3.1)$$

where

- UT_i = number of 100-car unit trains required for run_i
- TPY_i = tons per year for run_i (tons)
- $CAPT$ = capacity of each unit train (tons)
- RTY_i = round trips per year for each unit train operating on run_i .

FIGURE 3.7. Bottom-Dump Hopper Car (McGraw 1979)

FIGURE 3.8. High-Side Gondola Car (McGraw 1979)

The number of round trips per year is

$$RTY_i = \frac{h (AT)}{t_i} \quad (3.2)$$

where

h = hours in a year (8760 hr)

AT = availability of the track (fraction)

t_i = hours per round trip on run_i (hours).

The hours in a round trip on run_i are

$$t_i = \frac{2M_i}{\bar{S}_i} + t_{mlu} \quad (3.3)$$

where

M_i = the one-way mileage on run_i (miles)

S_i = the average speed of trains on run_i

t_{mlu} = time needed for maintenance, loading, and unloading (hours).

The average speed of trains on run_i is

$$\bar{S}_i = \frac{2 (S_l)(S_u)(S_b)}{2 (S_l)(S_u)(b_i) + (1-b_i) (S_u + S_l) S_b} \quad (3.4)$$

where

b_i = portion of run_i containing bottlenecks (fraction)

S_b = speed of train in bottlenecks (mph)

S_l = speed of train in loaded run (mph)

S_u = speed of train in unloaded run (mph).

The time required for maintenance, loading, and unloading is

$$t_{mlu} = t_l + t_u + t_m \quad (3.5)$$

where

- t_l = time needed for loading (hours)
- t_u = time needed for unloading (hours)
- t_m = time needed for routine maintenance (hours).

Rewriting RTY_i

$$RTY_i = \frac{h(AT)}{(2M_i/\bar{S}_i) + t_{mlu}} \quad (3.6)$$

Rewriting UT_i

$$UT_i = \frac{TPY_i [(2M_i/\bar{S}_i) + t_{mlu}]}{CAPT(h)(AT)} \quad (3.7)$$

Finally, UT_i reveals the number of unit trains required for run_i . Assuming that unit trains are comprised of 100 cars with 100-ton capacities, the fractional portion of UT_i will reveal the number of additional cars that must be apportioned to the 100-car unit trains. For example, on run_A if $UT_i = 15.3$, then fifteen 100-car unit trains are needed with 30 (0.3×100 cars) excess cars. Assuming each train can handle 10 additional cars without a significant reduction in speed, then 15-unit trains are needed for run_A consisting of 102 cars each. Rolling stock requirements may be determined as follows

$$\text{Locomotives: } L_i = (LT)(IUT_i)(1 + R_l) \quad (3.8)$$

where

- L_i = total locomotives required on run_i
- LT = number of locomotives per train
- IUT_i = integer portion of unit trains required on run_i
- R_l = reserve margin of locomotives.

$$\text{Coal cars: } C_i = (CT)(UT_i)(1 + R_c) \quad (3.9)$$

where

C_i = total coal cars required on run_i

CT = number of coal cars per train

UT_i = unit trains required on run_i

R_C = reserve margin of coal cars.

$$\text{Cabooses: } W_i = IUT_i (1 + R_w) \quad (3.10)$$

where

W_i = total cabooses required on run_i

R_w = reserve margin of cabooses.

Once the total rolling stock requirements are determined, the capital investment may be calculated by multiplying L_i , C_i , and W_i by their respective costs.

Track and Roadbed

Several elements make up the railway. The roadbed refers to the base constructed to support the track. The track itself consists of ballast, ties, and rail. A traffic control signaling system and grade crossing signals are often provided, especially on intensively used rail lines.

Unit train speed on long-distance coal hauls is mainly dependent on track conditions, characteristics and capacity but averages about 20 to 50 mph. For coal hauls from Western coal fields to Midwest markets, the average round trip speed is 22 mph (OTA 1978b). However, with appropriate upgrading of track, higher speeds are achievable.

One factor that affects train speeds is the grade. For a given grade, a certain horsepower per ton (HP/T) ratio is required to maintain a certain speed (Figure 3.9). As the grade increases, train speed decreases for a particular HP/T ratio.

Another factor affecting average train speed is bottlenecks. Bottlenecks are portions of the track where train speeds may be as slow as 10 to 20 mph due

FIGURE 3.9. Horsepower Requirements by Speed and Grade
(Rieber and Soo 1977)

to track congestion. Populated areas, major traffic centers, and weather conditions are often causes of bottlenecks. On a long haul, as much as 10% of the route may contain bottlenecks.

Track condition also has an impact on train speed. With good track conditions train speed may be increased, which in turn lowers the round-trip cycle time and rolling stock requirements. Some experts feel that good track conditions are the major factor in the financial success of unit train operations (Low-Beer 1979).

Coal Handling Terminals

Coal loading at most Western mines is accomplished by flood loading. In this method, a unit train passes through an opening in the coal storage silos at a constant speed (approximately 0.5 to 1.25 mph). Chutes above the train

fill the coal cars at a rate of about 3500 to 4000 tons/hour. A flood loading facility can load an entire unit train in as little as 2.5 hours, although 4 hours is a more typical loading time.

At the power plant, coal is unloaded by either the bottom-dump method or the rotary-dump method. The bottom-dump method involves moving the unit train on a trestle over a coal pile. Coal is dumped through cars via hatches that are tripped manually or automatically. The bottom-dump method is capable of unloading a 100-car unit train in 30 minutes. However, the bottom-dump method results in higher maintenance costs and higher initial investment than unloading by the rotary-dumping method. In rotary dumping, hopper or gondola cars are positioned and then turned over, individually or in pairs, while remaining coupled to the unit train (Figure 3.10). The rotary-dump method is capable of dumping one car every 100 seconds; just under 3 hours for an entire unit train. However, up to 4 hours is allowed for unit train unloading.

Rotary dumping is often favored as a coal unloading method because it can accept a combination of bottom-dump and nonbottom-dump coal cars and because it can handle frozen coal more effectively during the winter months.

FIGURE 3.10. Rotary Car Dumper Unloading Facility (McGraw 1979)

3.2.2 Resource Requirements

Energy, manpower, and major material requirements for rail transportation of coal are discussed below. Methods for estimating energy and material resource requirements for a unit train coal-delivery system and the primary efficiency of transporting the coal are also addressed in this section.

Energy

The energy used in unit train operations is dependent on the fuel consumption of locomotives (gal/mile), the number of locomotives per train, and the heat value of the fuel used (Btu/gal). Locomotives use diesel fuel Type R-R, which is roughly equivalent in heat value to distillate fuel oil (approximately 138,000 Btu/gal).

Fuel consumption is a function of speed, grade, number of curves, and power-to-weight ratio (hp/ton). Therefore, unless detailed information about characteristics of a specific route is available, the fuel consumption must be approximated. Based on information contained in Coal-By-Wire (1979) and OTA (1978B), an average fuel consumption of 3.4 gal/locomotive-mile is assumed.

The total annual energy consumed on run_i can be calculated as

$$TAE_i = (LT)(LFC)(H)(2 M_i)(RTY_i)(IUT_i) \quad (3.11)$$

where

TAE_i = total annual energy consumed on run_i (Btu/year)

LT = locomotives per train

LFC = locomotive fuel consumption (gal/locomotive-mile)

H = heat value of fuel (Btu/gal)

M_i = one-way distance of run_i (miles)

RTY_i = round trips per year per unit train on run_i

IUT_i = number of unit trains on run_i.

Using the values assumed above, for a five-locomotive unit train this expression can be reduced to

$$TAE_i = 2.346 \times 10^6 (2M_i)(RTY_i)(IUT_i) \quad (3.12)$$

In addition to the energy required for locomotive operations, coal is lost due to blowoff of fine coal dust out of open coal cars while the train is in transit. Little data exist as to the amount of coal lost due to blowoff. One estimate by Resources for the Future is that 0.1% of the total tonnage transported by rail is lost in loading, transit, and unloading activities. However, this figure is not precise and most likely will vary. Still, the primary efficiency of transporting coal by unit train is most likely between 99% and 100%.

Manpower

Bechtel (1978) estimated that operation of a unit train to transport 10^{12} Btu of coal equivalent would require approximately 7.02 man-years. This value translates to 1.28×10^{-4} man-years/ton coal transported.^(a)

Major Materials

Numerous materials are used in a unit train coal-delivery system. Steel is required for rail, locomotives, coal cars, cabooses, loading facilities, and unloading facilities. Wood is required for ties, and crushed rock is required for ballast. In addition, many other types of materials are needed in this delivery system; however, the analysis in this study will be confined to the requirement of the major material types identified above.

Steel requirements can be characterized by the steel needed for track, rolling stock and coal-handling facilities. Due to a lack of available data, the steel requirements for coal-handling facilities were not determined. The steel requirements for track and rolling stock are discussed below.

The amount of steel needed for rail includes the steel required for new or initially upgraded track and the steel required for track that is replaced because of wear during the life of the project. For 132 lb rail, which is the normal type used for heavy rail traffic, 242 tons of steel are required for each mile of single track. Therefore, the initial amount of steel required for a specific run_i is

(a) Assuming 9100 Btu/lb of coal.

$$ISR_i = 242 (M_{ni} + M_{ui}) \quad (3.13)$$

where

ISR_i = initial steel required for run_i (tons)

M_{ni} = distance of new track required for run_i (miles)

M_{ui} = distance of upgraded track required for run_i (miles).

To determine the amount of steel required for rail that is replaced over the project lifetime, the annual rail replacement rate must be known.

Annual rail replacement rate is based on rail life, which is governed by aggregate loading. One railroad company has observed the rail life under 60-ton capacity cars to be 400 million gross tons on curves and 650 million gross tons on straightaways (OTA 1978c). A value of 500 million gross tons was chosen to represent the average rail life when 100-ton capacity cars are used (OTA 1978c).

Each round trip of a unit train involves one loaded and one empty pass of the one-way route distance. Assuming the use of 100-ton capacity coal cars, the gross weight of a loaded train is

$$\text{Loaded Train Weight} = (W_l)(LT) + 131 \text{ CT} + W_c \quad (3.14)$$

where

W_l = weight of each locomotive (tons)

LT = number of locomotives per train

131 = gross weight of a loaded 100-ton hopper car (31 tons tare + 100 tons of coal) (tons)

CT = number of coal cars per train

W_c = weight of caboose (tons).

The total load (W_t) exerted by a unit train per round trip would be

$$W_t = 2 (W_l)(LT) + 162 \text{ CT} + 2 W_c \quad (3.15)$$

where

162 = a 31-ton car moving round trip and 100 tons of coal moving one way.

The rail replacement rate would therefore be $W_t/500 \times 10^6$. To calculate the annual replacement rate, the number of trips per year and number of unit trains must be added to the equation

$$Rr_i = \frac{RTY_i (IUT_i)(W_t)}{500 \times 10^6} \quad (3.16)$$

where

Rr_i = the annual rail replacement rate for run_i
 RTY_i = the number of round trips per year per unit train on run_i
 IUT_i = number of unit trains on run_i.

Finally, the amount of steel needed for rail replacement can be expressed as

$$ASR_i = 242 Rr_i M_i \quad (3.17)$$

where

ASR_i = annual steel requirements for rail on run_i (tons)
 M_i = total one-way distance on run_i (miles).

The total steel required for the life of a project is then

$$TSR_i = (PL) (ASR_i) + ISR_i \quad (3.18)$$

or

$$TSR_i = 242 ((PL)(Rr_i)(M_i) + M_{ni} + M_{ui}) \quad (3.19)$$

where

TSR_i = total steel requirements for rail on run_i (tons)

PL = life of coal delivery project (years).

To determine the steel required for locomotives, coal cars, and cabooses, the total amount of rolling stock must be known. Using the methodology for determining rolling stock requirements (Equations 3.1 to 3.10), the following relationship can be applied:

$$RSSR_i = L_i (LS) + C_i (CS) + W_i (WS) \quad (3.20)$$

where

$RSSR_i$ = rolling stock steel requirements for run_i (tons)

L_i = total locomotives required for run_i

LS = amount of steel used in a locomotive (tons)

C_i = total coal cars required for run_i

CS = amount of steel used in a hopper car (tons)

W_i = total cabooses required for run_i

WS = amount of steel used in a caboose (tons).

Coal cars weigh about 31 tons and are essentially 100% steel. Locomotives are about 85% steel and would therefore require 157 tons of steel. Cabooses require about 26 tons of steel. The total steel required for rolling stock can be rewritten as

$$RSSR_i = 157 L_i + 31 C_i + 26 W_i \quad (3.21)$$

If a coal delivery system lasts for 30 years, two purchases of rolling stock will be required, or $2 RSSR_i$ for the total life of the project.

The preceding calculation of steel requirements for rail and rolling stock accounts for the total steel required for a hypothetical rail system. No allowances are made for the scrap steel from replaced track and retired rolling stock. However, scrap steel from such a system would be significant since replaced rail is only about 5% consumed. Therefore, a complete accounting of steel usage would need to include any recycling of steel.

In addition to steel, crushed rock for ballast and wood for ties are required for all sections of track. Single track requires 2700 tons of crushed rock and 138,000 board-feet of wood per mile of track. Using Equation 3.19, the total crushed rock and wood requirements for a coal delivery system can be expressed as

$$TCR_i = 2700 [(PL)(Rr_i)(M_i) + M_{ni} + M_{ui}] \quad (3.22)$$

and

$$TWR_i = 138,000 [(PL)(Rr_i)(M_i) + M_{ni} + M_{ui}] \quad 3.23)$$

where

TCR_i = total crushed rock required for run_i (tons)

TWR_i = total wood required for run_i (board-ft).

3.2.3 Unit Train Economics

The cost of unit train transportation is complex. Some variable costs and some fixed costs, such as rolling stock, fuel, and rolling-stock maintenance, can easily be attributed to a specific coal movement. Other costs, such as new track and initial upgrading of track to handle a new coal movement, are not so clearly attributable. The total direct costs required to provide unit train service for a new coal movement (regardless of who actually pays) are examined in this section.

Unit train costs are very difficult to estimate for two reasons. First, cost information is proprietary and difficult to obtain from railroad companies and manufacturers. The little published data that exist have been escalated to 1981 dollars using the AAR Railroad Cost Recovery Index (AAR 1982) and are somewhat speculative. Second, a large portion of railroad transport costs are joint and common and are difficult to allocate to specific movements. Due to the dedicated use of rolling stock for coal movement considered in this study and the intensive use of a selected way, many costs can be allocated to the coal movement. However, certain costs such as overhead, administration, and insurance must still be allocated.

The following discussion examines the direct costs associated with a dedicated unit train coal-delivery system. Actual rail rates charged for a coal movement could be in the range of 160% of variable costs, based on interpretation of the Staggers Rail Act of 1980 (McGraw 1981). However, according to the ICC, there is no set rule as to how railroads should allocate indirect fixed costs to certain coal movements.

Capital Costs

Five categories of capital costs were identified for unit trains:

- rolling stock
- new track
- initial upgrading of existing track
- loading facilities
- unloading facilities.

Each category is discussed below.

Rolling stock capital costs include the cost of locomotives, coal cars, and cabooses. Based on information obtained from the railroads (McGraw 1981; AAR 1982), rolling stock components have the following costs (1981 dollars):

locomotive	\$790,000
coal car	\$ 45,000
caboose	\$ 70,000

When these costs are multiplied by rolling stock requirements for the corresponding car type, the total rolling stock investment cost can be determined. Since the life of the rolling stock is assumed to be 15 years for all car types, two of the above investments must be made over the project life of 30 years.

New track is needed for rail spurs from a main line to a power plant or mine. In addition, new track, which improves average speeds and reduces impacts of unit train operations, may be required to bypass congested areas. New track is defined here as a totally new way that includes right-of-way, clearing and excavating, roadbed, ballast, ties, rail, and signalling system.

The cost of new track varies greatly depending on soil and subgrade characteristics, terrain, climate, expected traffic volume, and the size and weight of trains. Also, new track costs are difficult to obtain since very little new main line track has been constructed for several decades. One exception is a recently constructed line that links two main lines in the Powder River Basin of Wyoming and which will carry unit train coal traffic. The 127-mile link, which extends from Gillette to Orin, averaged just under one million dollars per mile. For this study, \$1.1 million/mile (1981 dollars) is assumed for new track construction. This value represents the upper range of new track costs as presented in some recent studies (OTA 1978b; Means 1978; Rieber and Soo 1977; Ebeling and Dalsted 1979).

In addition to new track, existing main line track must often be upgraded to handle the weight and density of unit train traffic. Upgrading involves replacing rail, ties, and ballast over existing roadbed. Upgrading costs cited in several studies generally range from \$200,000 to 300,000/mile. For this study, \$300,000/mile is assumed for upgrading costs (1981 dollars). This value was confirmed by railroad companies as being a representative average cost. When the cost of new track and upgraded track are multiplied by their respective mileage, the total investment cost for track may be determined.

Cost information pertaining to loading facilities and reported in the available literature is fragmentary. With one exception, loading-facility cost information is reported for specific case examples, if at all. The OTA (1978b) report, however, listed generic cost information based on annual coal output. This information has been escalated to 1981 dollars and is presented in Table 3.3.

An average mine size of 5 million tons per year has been assumed. This size is representative of large-scale surface mines occurring in the Powder River Basin in Wyoming. When annual coal requirements exceed 5 million tons per year, multiple mines may be required.

As with loading facility costs, unloading facility cost information is scarce. Table 3.4 shows generic unloading facility costs obtained from the OTA (1978b) study, escalated to 1981 dollars.

TABLE 3.3. Coal Loading Facility Capital Costs^(a)

Annual Capacity (million tons)	Facility Cost ^(b)	Rail Cost ^(c)
2.0	3,500,000	2,200,000
3.5	7,000,000	2,200,000
4.3	7,300,000	2,200,000
5.0	7,500,000	2,200,000
5.3	7,700,000	2,200,000
8.5	8,300,000	2,200,000
9.0	8,500,000	2,200,000

(a) OTA 1978a.

(b) Using the Handy-Whitman Index (Whitman, Requart, and Associates 1982), costs were escalated to 1981 dollars.

(c) Using the AAR Railroad Cost Recovery Index (1982), costs were escalated to 1981 dollars.

TABLE 3.4. Coal Unloading Facility Capital Costs^(a)

Annual Capacity (million tons)	Facility Cost ^(b)	Rail Cost ^(c)
3.4	14,900,000	1,500,000
3.6	16,000,000	1,500,000
5.6	20,200,000	1,500,000
6.0	20,300,000	1,500,000
7.0 ^(d)	20,600,000	1,500,000

(a) OTA 1978b.

(b) Using the Handy-Whitman Index (Whitman, Requart, and Associates 1982), costs were escalated to 1981 dollars.

(c) Using the AAR Railroad Cost Recovery Index (1982), costs were escalated to 1981 dollars.

(d) Estimated based on 5.6 and 6.0 million ton facility costs.

Two 1000-MW coal-fired units operating at 75% capacity factor require about 7 million tons of subbituminous coal per year. Both units are assumed to share one unloading facility with 7 million ton per year capacity. An unloading facility, including rail loop, of 7 million ton per year capacity costs \$22.1 million (1981 dollars) using OTA data (1978b).

Operating Costs

Five categories of operating costs were identified:

- labor and materials for rolling stock maintenance
- fuel and crew costs for unit train operation
- labor and materials for track maintenance
- labor and materials for loading facilities operation and maintenance
- labor and materials for unloading facilities operation and maintenance.

Each category is discussed below.

Costs of maintaining rolling stock can be estimated on a cents-per-mile basis for each car type. Based on data from McGraw (1979), OTA (1978b), and White et al. (1980), the following maintenance costs were established for rolling stock:

coal car	6.4¢/mile
caboose	3.0¢/mile
locomotive	52¢/mile

Total annual maintenance cost for a complete unit train coal-delivery system may be calculated by multiplying the above costs by annual mileage and number of cars (exclusive of reserves).

Fuel costs can be highly variable and therefore difficult to estimate without a precise description of a specific route. Fuel consumption varies according to grade, train speed, number of curves, and power-to-weight ratio of the train. Based on an average fuel consumption of 3.4 gallons/locomotive-mile, fuel costs may be calculated (OTA 1978b; Coal-By-Wire 1979). Using the

relationship for calculating total annual energy consumption for a unit train delivery system (Equations 3.11 and 3.12), the following equation will provide annual fuel costs:

$$AFC_i = \frac{FC (TAE_i)}{10^6} \quad (3.24)$$

where

AFC_i = annual fuel cost on run_i (\$)

FC = cost of fuel (\$/10⁶ Btu)

TAE_i = total annual energy consumption on run_i (Btu/year).

Based on Equation 3.12, which assumes five locomotives per unit train, the above relationship can be rewritten as

$$AFC_i = 2.346 (2M_i)(RTY_i)(IUT_i)(FC) \quad (3.25)$$

where

M_i = one-way distance on run_i (miles)

RTY_i = round trips per year per unit train on run_i

IUT_i = number of unit trains on run_i.

Crew costs were estimated based on information in OTA (1978b) to be \$590 for each 100 miles of travel. Therefore, crew costs may be expressed as

$$ACC_i = 5.9 TMY_i \quad (3.26)$$

where

ACC_i = annual crew costs on run_i (\$)

TMY_i = total miles per year traveled on run_i (miles).

The cost of maintaining track should theoretically be apportioned to the traffic that uses the track. Intensive unit train traffic causes track to deteriorate more rapidly than does normal freight. Therefore, coal unit trains should be burdened with track maintenance costs that are proportionate to their contribution to track wear.

Track maintenance costs reflect maintenance of way, as well as replacement of worn rail. Maintenance of way costs have been estimated by White et al. (1980) at \$0.49/gross ton-mile (GTM). Escalating this cost by the AAR Cost Index (1982) to 1981 dollars results in \$0.54/GTM. The following equation estimates annual track maintenance cost based on the rail replacement rate (Equation 3.16), total gross ton miles, and component cost factors.

$$TMC_i = Rr_i(M_i)(TRC) + 2M_i(RTY_i)(UT_i)(W_t)(MOWC) \quad (3.27)$$

where

TMC_i = annual track maintenance cost on run_i (\$)

Rr_i = annual rail replacement rate on run_i (fraction)

M_i = one way distance on run_i (miles)

TRC = track replacement cost (\$/mile)

UT_i = number of 100 car unit trains required for run_i

$MOWC$ = maintenance of way cost (\$/gross ton-mile)

W_t = total load exerted by a unit train per round trip (tonnes).

The cost of operating and maintaining loading facilities was estimated based on information from OTA (1978b). Table 3.5 shows O&M costs of loading facilities taken from OTA and escalated to 1981 dollars.

For a 5-million ton per year mine and loading facility, a total annual cost (1981 dollars) of \$1,040,000 would be needed for operation and maintenance.

The costs of operating and maintaining unloading facilities were estimated based on information from OTA (1978b). Table 3.6 shows O&M costs for unloading facilities based on OTA information and escalated to 1981 dollars.

Assuming a 7 million ton unloading facility for two 1000 MW plants, about \$2.23 million dollars would be required for operation and maintenance. In actuality, these costs would be included in the O&M costs for the generating facilities. However, in comparing the cost of transportation alternatives, these costs must be included.

TABLE 3.5. Coal Loading Facility O&M Costs^(a)

Annual Capacity (million tons)	Facility Cost ^(b)	Rail Cost ^(c)
2.0	470,000	40,000
3.5	920,000	40,000
4.3	970,000	40,000
5.0	1,000,000	40,000
5.3	1,040,000	40,000
8.5	1,220,000	40,000
9.0	1,250,000	40,000

(a) OTA 1978b.

(b) Using the Handy-Whitman Index (Whitman, Requart, and Associates 1982), costs were escalated to 1981 dollars.

(c) Using the AAR Railroad Cost Recovery Index (1982), costs were escalated to 1981 dollars.

TABLE 3.6. Coal Unloading Facility O&M Costs^(a)

Annual Capacity (million tons)	Facility Cost ^(b)	Rail Cost ^(c)
3.4	1,520,000	27,000
3.6	1,600,000	27,000
5.6	2,090,000	27,000
6.0	2,120,000	27,000
7.0 ^(d)	2,200,000	27,000

(a) OTA 1978b.

(b) Using the Handy-Whitman Index (Whitman, Requart, and Associates 1982), costs were escalated to 1981 dollars.

(c) Using the AAR Railroad Cost Recovery Index (1982), costs were escalated to 1981 dollars.

(d) Extrapolated based on 5.6 and 6.0 million ton facility costs.

3.2.4 Environmental Effects

The principal environmental effects associated with rail transport of coal are atmospheric emissions, noise, and accident rates.

Increased unit train operation will have the greatest environmental consequence for communities through which the trains pass. Many towns, especially in the West, have been built around the railroads, and rights-of-way often divide major portions of towns. Additional unit train operations will increase the volume of traffic and disrupt local transportation, land use and social patterns of the residents. Measurable aspects of community disruption include increases in grade crossing accidents, noise levels and air pollutant, and dust emissions. Social impacts, however, are difficult to measure or estimate.

Atmospheric Emissions

Particulates account for most of the air pollutants emitted by unit train transport of coal. Particulate emissions are produced during loading, in transit, and during unloading of coal cars. The quantity of coal lost during transport will vary from region to region, depending on train speed, type of coal, windspeed, condition of rolling stock, moisture, and initial quantity of fuels. Estimates of quantity losses range between 0 and 1% of total coal shipped; however, one estimate reached as high as 5% (U.S. DOE 1980). Estimates for particulate emissions during loading and unloading can range from 0.2 lb per ton for controlled facilities and 0.4 lb per ton for uncontrolled facilities (U.S. DOE 1980). Assuming 0.25% loss in transit, and 0.2 lb per ton loss during both loading and unloading, a total of 5.2 lb per ton of coal transported will be emitted as particulate matter. Fugitive emissions from unit train transport of coal could present some air-quality concerns, depending on the location of the track and loading and unloading facilities.

At modern train loading facilities, water jets are used to suppress coal dust. Dust emissions are confined to an area extending a few feet from the silo exit and entrance and do not pose a community air pollution problem. The extent of windage losses in transit is controversial (Chironas 1978). Reduction in windage losses can be accomplished, if required, by water or fuel oil sprays, latex sealants, windguards, or closed cars.

Diesel-electric locomotives emit carbon monoxide (CO, hydrocarbons (HC), nitrogen oxides (chiefly nitric oxide, NO), particulates, and other pollutants. The amount of each pollutant emitted depends upon several factors, including fuel composition and heating value, load, grade, and abatement equipment. Table 3.7 presents emissions in terms of pounds of pollutants emitted per 1000 gallons of diesel fuel consumed.

The environmental impact of these pollutants is difficult to assess. They represent a source of increased air emissions, yet they are neither from a stationary source, such as a power plant, nor from a continuous mobile source, such as continuous automobile passage. Train passage is a relatively isolated event, with opportunity for pollutant dispersal during intervals between train passages. The impact of emissions from unit train operations cannot be compared in any meaningful manner to stationary source emissions associated with Coal Slurry pipeline operation. Pipeline-related emissions are from central power plants that produce the electric energy for pipeline uses, whereas unit train emissions are dispersed over the length of the rail route.

TABLE 3.7. Diesel Locomotive Emissions, lb/1000 Gal Fuel Consumed^(a)

Pollutant	Engine Type		
	2-Stroke Supercharged Road	2-Stroke Turbocharged Road	4-Stroke Road
Carbon monoxide	66	160	180
Hydrocarbons	148	28	99
Nitrogen oxides (NO _x as NO ₂)	350	330	470
Particulates ^(b)	-- ^(c)	25 ^(d)	--
Sulfur oxides	--	57 ^(d)	--
Aldehydes (as HCHO)	--	5.5 ^(d)	--
Organic acids	--	7 ^(d)	--

(a) OTA 1978c.

(b) Based upon highway diesel emissions; no actual locomotive particulate emission test data available.

(c) Indicates data not available.

(d) Based upon national distribution of engine types.

Noise

Another impact of increased train traffic is noise. The principal sources of noise are the diesel engines and electric traction motors, the interaction between wheels and rails, and the vibrations of hopper cars. Maximum train sound levels range between 80 and 100 decibels (dBA) at a distance of 50 feet, but the perception of sound is subjective and may be reduced by landforms, thick vegetation, and buildings. The day-night average sound, L_{dn} , is a noise-exposure measure weighted more heavily for nighttime than for daytime. The Environmental Protection Agency has judged the level of 55 dBA to be the maximum allowable L_{dn} . Table 3.8 identifies EPA recommended noise levels.

TABLE 3.8. Summary of Noise Levels Identified by EPA as Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety^(a)

<u>Effect Protected Against</u>	<u>Recommended Noise Level</u>	<u>Areas</u>
Hearing loss	$L_{eq}(24)^{(b)} \leq 70$ dBA	All areas.
Outdoor activity interference and annoyance	$L_{dn} \leq 55$ dB	Outdoors in residential areas and farms and other outdoor areas where people spend widely varying amounts of time and other places in which quiet is a basis for use.
	$L_{eq}(24) \leq 55$ dBA	Outdoor areas where people spend limited amounts of time, such as schoolyards, playgrounds, etc.
Indoor activity interference and annoyance	$L_{dn} \leq 45$ dBA	Indoor residential areas.
	$L_{eq}(24) \leq 45$ dBA	Other indoor areas with human activities such as schools, etc.

(a) OTA 1978c.

(b) L_{eq} is the constant A-weighted sound level that conveys an equivalent amount of sound energy as does an A-weighted time-varying sound over a given time period. $L_{eq}(24)$ is the L_{eq} of a 24-hr period.

The effects of unit train traffic on L_{dn} noise levels are presented in Figure 3.11. For a given volume of train traffic, L_{dn} may be predicted based on distance from the track. To determine the population affected by excessive train noise (as determined by the EPA guidelines), the population density within a given distance of the track must be known. Using Table 3.8 and Figure 3.11, the population exposed to excessive noise may be determined.

The impact of increased noise on the lives of the affected people is difficult to assess because noise impacts depend heavily upon subjective factors, which vary from individual to individual. Several factors may influence individual perception of noise:

- length and speed of the train
- time of day noise occurs (this is considered in estimating the L_{dn} value)

FIGURE 3.11. Effects of Unit Train Volume on L_{dn} Noise Levels

- whether building windows are opened or closed
- background noise level when trains are not present
- presence of particularly disturbing or pleasing sound frequencies (i.e., some people may enjoy the sound of a train horn in the night, while others may dislike it)
- history of prior exposure to train noise
- history of noise exposure in general.

The number of people impacted by train noise would be greatest in urban areas. Background noise and noise tolerance may well be highest in these areas, however, thereby minimizing the subjective response to the increased train noise. Methods for predicting railside noise contours were developed for the OTA study (1978c) based on earlier work by Swing (1975).

Accident Rates

Accident rates identified with rail transport of coal include rail-highway grade crossing accidents and occupational accidents.

In the period 1965 to 1974, an annual average of approximately 5000 accidents occurred at rail-highway grade crossings in the U.S. On the average, approximately 1950 fatalities per year resulted from these accidents (OTA 1978c). Accident rates are a function of crossing protection, number of tracks, number of trains and vehicles per day, time of day, and whether the setting is rural or urban. Analysis of 3870 grade crossings in 21 states clearly indicates that increases in unit train operation will result in increased accidents (OTA 1978c); however, the increase is not directly proportional to the increase in freight volume. Grade-crossing accidents can be mitigated by providing signals at grade crossings, automatic crossing gates and grade separations. Given rail and highway traffic and crossing characteristics, models have been developed for predicting grade crossing accidents. The Coleman-Stewart model (Coleman and Stewart 1977) and the Florida Department of Transportation model (Lavette 1977) are summarized in the OTA study (1978c). For example, using accident prediction models, the OTA-sponsored study estimated that for the Gillette, Wyoming - Houston, Texas route, a 90%

increase in rail operations would result in a 21% increase in deaths and injuries attributable to grade crossing accidents.

Increased train traffic in communities that are divided by railroad tracks without grade separations could delay emergency fire, medical, or police vehicles from reaching emergency situations, as well as increase traffic congestion on busy arterials. Grade separations and community bypasses could be considered where delays and congestion are significant. Increased rail traffic could also interfere with farming operations on land bisected by rail rights-of-way.

Estimated occupational accident rates involving rail transport of coal are 1.1×10^{-6} fatal injuries and 1.1×10^{-5} nonfatal accidents (with 59.5 man-days lost per occurrence) for every ton of coal shipped (Bliss et al. 1977).

3.3 SLURRY PIPELINE TRANSPORT

Slurry pipelines are in operation throughout the world. Operating in Tasmania, South Africa, Japan, and North and South America, slurry pipelines carry a wide range of commodities including limestone, iron, copper, zinc-concentrate, kaoline, and coal. The world's longest and largest coal slurry pipeline is the Black mesa line, which began operation in 1970. This 18-in. diameter pipeline moves over 5-1/2 million tons of coal per year from the Kayenta coal mine in Arizona to the Mohave generating station in southern Nevada, 273 miles away.

Over particular routes the Coal Slurry pipeline has several advantages over other forms of coal transportation. For example, the Black Mesa coal mines are located 120 miles north of the nearest railroad and the receiving station is located 30 miles north of the nearest railroad. Had the coal been shipped by rail, the total distance would have been 400 miles (including 150 miles of new rail facility), 127 miles more than the pipeline.

Slurry pipelines offer the potential for economic, environmentally sound transportation of large quantities of coal. Although the pipelines have had only limited applications so far (only two lines have been built in the U.S. and only one is presently operating), the technology has been fully developed

and several lines are in the design or planning phase. As indicated by Figure 3.4, several proposed lines originate in Western coal fields. One of the more formidable problems facing pipeline planners is water availability in the semi-arid West.

The purpose of this section is to describe the technology, resource commitments, economics, and environmental effects of coal slurry pipelines. The technology of coal slurry pipeline transportation consists of mixing crushed coal with water, pumping the slurry through a pipe, and separating the coal from the water at its destination. These processes will be described in detail in the first part of this section. In addition to water, resources that must be committed to a pipeline include steel, concrete, and energy. The quantities required for large pipelines (greater than 20 million tons per year) are estimated in the second part of this section. The costs of slurry pipeline transportation are dominated by construction costs, which complicate financing but have the advantage of relative immunity to inflation. The third part of this section describes cost parameters and provides generic cost estimates. The major environmental effects associated with slurry pipelines occur during the construction phase, but minor and potential environmental problems exist during operation. These effects are addressed qualitatively in the fourth part of this section.

Much controversy has surrounded coal slurry pipeline developments. Proponents include environmentalists, utilities, and construction companies, while opponents include environmentalists and railroads. The first line in the United States was built in Ohio in the 1950s as a response to increasing rail tariffs. The 108-mile pipeline operated for only a few years because the railroad developed the unit train concept, which allowed them to lower their tariff. Slurry pipelines do not yet have the right of eminent domain and railroads can refuse to allow pipelines to cross their rights-of-way. This obstacle may soon be eliminated as Congress is considering granting eminent domain to slurry pipelines, and one pipeline company has successfully challenged the railroad's refusal for passage in 65 lawsuits.

Environmentalists are split on the issue of Coal Slurry pipelines. Some object to all energy developments due to aesthetic reasons and particularly to slurry pipelines because of their use of water. Other environmentally conscious individuals support slurry pipelines because they believe that development of Western coal is inevitable and should be accomplished in the most environmentally sound manner. This report will not deal any further with these controversies, but the reader should be aware of these differing viewpoints.

3.3.1 Technology Description

Operating a coal slurry pipeline involves crushing coal, mixing it with water, pumping it to its destination, and dewatering it. All of the components required are presently in widespread use in other applications. Coal crushers are employed extensively in coal-fired power plants; solid/liquid slurries are mixed and pumped every day from mines and industrial plants, and sludge dewatering is a common practice at water and waste water treatment plants. A schematic of a coal slurry pipeline is shown in Figure 3.12.

Slurry Preparation

Coal is assembled from a mine or group of mines at a single point where the slurry is prepared. Preparation begins with impact crushing followed by the addition of water and further grinding. Coal particles should be uniformly graded with at least 20% smaller than 325 mesh and the largest in the 14 to 20 mesh range (Herbich 1977). Water is then added to form a mixture that is about 50% dry coal by weight.

Slurries with other relative proportions are technically feasible, but the 50/50 mixture has been found to be near optimal. As shown in Figure 3.13, higher coal concentrations result in increased energy costs, whereas lower coal concentrations result in higher construction costs (Palmer, James and Hirsch 1977). Other fluids besides water can be used as the transport medium. Oil or alcohol refined from coal offer the technical advantage of eliminating the dewatering process and the psychological advantage of eliminating the water export from semi-arid regions (although the coal liquefaction process would probably require more water than a water slurry). However, the consensus among experts is that the technology of producing and burning such slurries is not yet commercially available (Papamarcos 1979).

FIGURE 3.12. Schematic of a Hypothetical Coal Slurry Pipeline

FIGURE 3.13. Unit Transportation Costs as a Function of Percent Solids in Slurry

Pipeline Transmission

The slurry is pumped from agitated storage tanks into a steel pipeline with positive displacement pumps. Pump stations are located approximately every 50 to 150 miles, depending upon terrain, pipe size, and other design considerations. Slurry pumps that handle up to 3 million tons of solids per year are commercially available, and larger pumps are being designed (Anderson 1979).

The critical velocity of slurry is between four and seven feet per second (NGPRP 1974). Below this range coal tends to settle and drag along the pipe invert, causing localized abrasion. At higher velocities, the slurry becomes abrasive on all pipe surfaces and friction losses become prohibitive. The Black Mesa line operates at about 5.5 feet per second. Another velocity constraint limits the slope of the pipeline to 16% (Anderson 1979).

Once started, the flow must be maintained or the coal will settle and possibly plug the pipe. Considerable controversy surrounds the likelihood of this event and the problems of restarting the pipeline following shutdown. To

prevent this type of settling, the operating pipeline at Black Mesa has ponds in which to empty the pipe's contents in the event of a flow stoppage.

Dewatering and Delivery

At the downstream terminal of the pipeline, the slurry must be dewatered. Dewatering may be accomplished by natural settling, vacuum filtration, centrifugation, or chemical flocculation. Typically, a combination of these processes would be employed as indicated in Figure 3.12. After additional drying by the application of heat, the coal can be stored, transported further by other modes, or used directly at a power plant. The reclaimed water could be used as makeup for an electric-generating station's cooling system.

3.3.2 Resource Requirements

Energy, manpower, land, water, and major material requirements of slurry pipeline transport of coal are discussed below. End uses of these resources are identified, and generic level estimates of the quantities required of each are provided. The limited literature available on this technology constrains the accuracy and credibility of these estimates.

Energy

Energy is required during both the construction and operating phases of a pipeline development. During construction, petroleum distillates are used to operate machinery such as bulldozers and backhoes. Estimated quantities of gasoline and diesel fuel are shown in Table 3.9.

The operational phase uses energy for coal crushing, slurry pumping, and coal separation. The largest use is for pumping, however. Frictional head losses in a coal slurry pipeline have been calculated (Herbich 1977). Assuming a pump efficiency of 70%, 4.6 hp per million ton-miles of annual capacity would be required to overcome friction losses. Coal crushing, cleaning, and slurry preparation would require about 1000 hp per million tons of coal annual capacity (OTA 1978b). The energy required at the downstream terminal would depend on the type of dewatering equipment employed. Gravity thickening would require about 50 hp; vacuum filtration or centrifugation would require about 5000 hp; and chemical clarification would require about 25 hp per million tons of coal

TABLE 3.9. Estimated Energy Requirements for Pipeline Construction^(a)

<u>Pipeline</u>	<u>Gasoline</u>	<u>Diesel</u>
Average fuel consumption for construction of five example pipelines (gal/mile)	3.1×10^3	5.8×10^3
Heat value (Btu/gal)	125×10^3	140×10^3
Energy equivalent (Btu/mile)	380×10^6	790×10^6
Total energy consumption (Btu/mile)	1200×10^6	
<u>Pumping Stations</u>		
Estimated fuel consumption for construction of one pumping station (gal/station)	60.7×10^3	111×10^3
Heat value (Btu/gal)	125×10^3	140×10^3
Energy equivalent (Btu/pumping station)	7400×10^3	$15,200 \times 10^6$
Total energy consumption (Btu/pumping station)	$22,600 \times 10^6$	

(a) Adapted from OTA 1978C.

annual capacity (Wesner et al. 1978). Pumping groundwater from a depth of 4000 ft with 60% efficient pumps would require 750 hp per million tons of coal annual capacity. In addition to the electric demands listed above, gas may be required to dry the coal prior to combustion. Estimates of the heat-rate penalty due to moisture in the coal range from as low as 2% (Anderson 1979) to 20% (PEDCO 1978). Because of this penalty, the coal slurry pipeline option requires more coal to be mined than other transportation options.

A fairly wide range of estimates exists concerning energy requirements for slurry pipeline transport of coal. One report estimates the auxiliary energy requirements of a slurry pipeline for a distance of 273 miles at 1.29×10^5 Btu per ton of coal transported (Faddick 1979). Another study estimated 1.23×10^6 Btu/ton for the same distance, and 6.24×10^5 Btu/ton for a distance of 1000 miles, using a more advanced technology (Bank 1979).

Manpower

The manpower requirements for construction and operation of a slurry pipeline are considerably less than for a unit train. A report by Faddick (1979) estimated 1.5×10^{-5} man-years per ton coal would be required for a slurry pipeline 1000 miles in length.

Land

Facilities associated with slurry transport of coal include the pipeline itself and associated right-of-way, pumping stations, slurry separation terminal and slurry dewatering terminal. The terminals of a coal slurry pipeline are major industrial complexes. The upstream terminal must include coal storage, water storage, cleaning and crushing facilities, slurry storage, and a pumping station. The downstream terminal must include slurry separation facilities, and coal storage and handling areas. Both terminals must have miscellaneous facilities such as offices and parking spaces. Depending on the plant's proximity to neighbors and local environmental ordinances, the largest land use may be for a buffer area to reduce noise and visual pollution. The total land requirement for each terminal of a 10-GWe pipeline could range from 100 to 200 acres.

The pipeline itself would require a right-of-way of up to 100 feet. Typically, the land is not purchased by a pipeline company; rather, the land owner is paid a one-time fee for an easement to build on his land. A 100-foot right-of-way would require a commitment of about 12 acres per mile. However, after construction the land may be reverted to agricultural or other nonstructural use.

Depending on terrain and design considerations, pump stations are required every 50 to 150 miles. The size of the pump building itself could be quite small--probably less than one acre. The station would require a buffer zone to reduce noise and emergency storage ponds to contain the pipeline contents in the event of a shutdown. If the stations were situated 50 miles apart, about 3 acre-feet of storage capacity would be required at each station per million tons of annual capacity. The total land area of each pumping station could be up to 40 acres.

Water

The water used in a coal slurry pipeline is "consumed" in the sense that it is not returned to its place of origin. The quantity of water necessary to operate a coal slurry pipeline is determined by two factors: annual throughput and solids concentration (Faddick 1979). The concentration of water to coal may vary between 40 to 60%, usually averaging just over 50% water by weight.

The largest end use of water is for the transport medium. Small quantities of water are also required for cleaning and crushing the coal and for domestic use. For a 50/50 slurry mixture by weight, about 750 acre-feet of water is required to transport 1 million tons of coal. Some of this could be provided by moisture contained naturally in the coal but other water requirements would roughly equal that quantity. Therefore, the water required to operate a coal slurry pipeline is estimated to be 750 acre feet per million tons of coal or 245 gallons of water per ton of coal.

Major Materials

The largest end use of steel is for the pipe itself, but steel is also used for concrete reinforcement and in all the pumps, motors, and miscellaneous equipment used in the pipeline operation.

The wall thickness of the pipe would be dependent on specific design parameters, but a 48-inch diameter pipe with a one-half-inch-thick wall would weigh approximately 260 lb per foot.^(a) A 1000 mile pipeline would, therefore, require about 690,000 tons of steel for the pipe itself. When all the pumps, motors, machinery, and miscellaneous steel uses are accounted for, the total resource commitment of a 1000 mile, 48-inch coal slurry pipeline could be over one million tons of steel. For pipelines greater than 20 million tons per year, the steel requirements can be estimated by

$$S = 25 \text{ MT} \quad (3.28)$$

(a) The 48-inch TAPS oil line has wall thickness ranging from 0.462 to 0.562 inches (U.S. Senate 1977).

where

S = tons of steel

M = length (miles)

T = capacity (tons per year).

Concrete is required for the foundations of buildings and facilities at the terminals and pump stations and may be required for other parts of the structures (such as walls or beams) or to support the pipe at difficult locations such as river crossings. Because the quantity required is very dependent on the specific design, generic estimates are inevitably imprecise. For large pipelines, each terminal would probably require about 100,000 cubic yards and each pump station may require about 10,000 cubic yards of concrete.

3.3.3 Coal Slurry Pipeline Economics

The largest component of slurry pipeline costs is the amortization of the construction cost. Therefore, fixed costs are relative high compared with those of other transportation options. This provides advantages and disadvantages to coal slurry pipeline operators. An advantage is relative immunity to the effects of inflation, but a disadvantage, is the problem of financing during periods of high interest rates.

Because a detailed cost analysis is beyond the scope of this generic study, cost data provided by other generic analyses have been extrapolated and escalated to 1981 dollars using the OGJ-Morgan Oil Pipeline Cost Index published in the Oil and Gas Journal (Morgan 1982). Because so few large slurry pipelines have been analyzed, detailed cost information on site-specific slurry pipelines is virtually nonexistent. Generic cost studies that have been generally accepted include those done by Bechtel Corporation for Brookhaven National Laboratory (Hogle et al. 1976) and General Research Corporation for the Office of Technology Assessment (OTA 1978b). Bechtel's estimates have been criticized by some as being unreasonably low (Sargent 1976). Therefore, the cost figures in this report are based primarily on the OTA report.

Capital cost consists of four main components including upstream terminal, downstream terminal, pump stations, and pipeline. Each component is described below.

Upstream Terminal

At the upstream terminal coal is washed, crushed, mixed with water to form a slurry, and pumped into the pipeline. An itemized cost breakdown for 24 components of the 5-million-ton-per-year Black Mesa line is listed in Table 3.10. Economies-of-scale exist up to a capacity of between 15 and 20 million tons per year. Costs for larger terminals increase linearly with capacity because multiple units are employed. The total capital cost of a large upstream terminal is estimated to be \$2.9 million per million tons of annual capacity.

Downstream Terminal

The major cost component at the downstream terminal is the dewatering equipment. Other cost components include coal handling facilities and water treatment equipment. An itemized cost breakdown of six components of the Black Mesa line is shown in Table 3.11. Economies-of-scale are not as great for downstream terminals as for upstream terminals, but they do exist up to about 15 million tons per year. The total capital cost of a large downstream terminal is estimated to be \$4.6 million per million tons of annual capacity.

Pump Stations

Pump stations are required at regular intervals to overcome pressure losses due to friction. Depending on the terrain, pipe diameter, steel strength, and other design parameters, pump stations are required every 50 to 150 miles. The capital cost of a pump station displays economies-of-scale up to about 10 million tons per year; at larger capacities, capital costs tend to increase linearly. The total capital cost of a large pump station is estimated to be \$0.5 million per million tons annual capacity.

Pipeline

The cost of installing a pipeline is dependent on the terrain through which it travels. Because of variable terrain, unit pipeline costs are quite variable. Large pipelines are estimated to cost \$0.029 million per mile per million tons of capacity. Analysis of 20 oil and gas pipelines installed in 1978 and 1979 agrees closely with this estimate (Oil and Gas Journal August 13, 1979).

TABLE 3.10. Itemized Capital Costs of the Upstream Terminal
of the Black Mesa Coal Slurry Pipeline^(a)

<u>Upstream Terminal</u>	<u>Million Dollars (1975)</u>
1. Transport from mine	1.5
2. Truck hopper	0.05
3. Initial crushing and cleaning	1.0
4. Stocking conveyor	0.2
5. Inactive storage	1.0
6. Raw storage	0.68
7. Active storage	1.0
8. Dozers and scrapers	0.6
9. Conveyor transfer tower	0.2
10. Transfer tower	0.3
11. Conveyor to bunkers	0.15
12. Bunkers and feeders	0.15
13. Operating plant	1.0
14. Vibrator	0.2
15. Impactor	0.5
16. Rod mill	1.5
17. Vibrator	0.15
18. Slurry holding tank	0.6
19. Slurry test loop	0.05
20. Land	0.05
21. Wells and water pumps	1.25
22. Water working storage	0.35
23. Water reservoir and pipe	0.3
24. Waterpiping and rust inhibitor injectors	<u>0.1</u>
Total	12.88

(a) Reiber and Soo 1977.

TABLE 3.11. Itemized Capital Costs of the Downstream Terminal of the Black Mesa Coal Slurry Pipeline^(a)

<u>Downstream Terminal</u>	<u>Million Dollars (1975)</u>
1. Permanent storage	4.8
2. Holding tanks	2.1
3. Dewatering centrifuges	4.0
4. Pulverizers	0.9
5. Flocculating tanks	0.7
6. Piping	<u>0.15</u>
Total Downstream	12.65

(a) Reiber and Soo 1977.

Total Capital Costs

Of the four capital cost components described above, two are independent of the pipeline length, whereas the other two are quite dependent on the length. The cost of the terminals depends only on their capacity, but the cost of the pipe itself depends on its length, and the total cost of pumping stations depends on the number of stations required. For generic estimates the capital cost of a coal slurry pipeline with a capacity greater than 20 million tons per year could be expressed as follows:

$$C = 7.5T + 0.029MT + 0.5PT \quad (3.29)$$

where

C = capital cost (millions of 1981 dollars)
T = capacity of line (million tons per year)
M = length of line (miles)
P = number of pump stations.

Operating and Maintenance Costs

Operating and maintenance costs of Coal Slurry pipelines include the costs of power, labor, materials and supplies, chemicals, and general administration. Almost no economies-of-scale exist for power and chemicals; small

economies-of-scale exist for labor and materials; and significant economies-of-scale exist for administration.

Based on the installed horsepower requirement estimated in the energy resource commitment part, the annual energy cost of a large coal slurry pipeline would be as follows:

$$EC = 3.0 \times 10^4 (PC)(T)(M) + 4.5 \times 10^7 (CF) \quad (3.30)$$

where

EC = energy cost (dollars per year)

PC = power cost (dollars per kWh)

CF = capacity factor.

Labor costs are split almost evenly between the upstream and downstream terminals with pump stations being only minor contributors. The total annual labor cost of a large pipeline is estimated to be \$0.23 million per million tons of annual capacity (OTA 1978b).

materials and supplies for a large pipeline are estimated to cost \$0.11 million at the upstream terminal, \$0.17 million at the downstream terminal, and \$0.02 million at each pump station per million tons of annual capacity (OTA 1978b).

Chemicals are used at the downstream terminal to separate the slurry and to treat the water. The total annual chemical cost of a large pipeline is estimated to be \$0.29 million per million tons of annual capacity (OTA 1978b).

Administration costs are split between the terminals. The total administration cost of a large pipeline is estimated to be \$0.11 million per million tons of annual capacity (OTA 1978).

Total operation and maintenance costs for a coal slurry pipeline can therefore be estimated as follows:

$$OM = EC + T(910,000 + 20,000 P) \quad (3.31)$$

where OM is operation and maintenance costs (dollars per year).

Total Slurry Pipeline Transportation Costs

Several other studies have been identified with published slurry pipeline cost estimates, but these are typically reported on the basis of cents or mill per ton-mile (Armbruster and Candela 1976; Campbell and Katell 1975; Hyde 1979; Sargent 1976) or on the basis of dollars per year for a given pipeline length and capacity (Anderson and Rogozen 1977). Cost estimates from these sources for a 1000-mile, 25-million-ton-per-year coal slurry pipeline are compared with those provided by Equations 3.29 and 3.31 in Table 3.12. Analysis of this table indicates a range of estimated pipeline costs, with this study's estimate toward the high end of this range.

3.3.4 Environmental Effects

The primary environmental effects of coal slurry pipeline construction and operation discussed in this section are waste water discharges and accident rates. Other environmental effects associated with slurry pipelines are those relating primarily to activities during construction.

TABLE 3.12. Comparison of Various Coal Slurry Pipeline Cost Estimates

<u>Source</u>	<u>Cost Year</u>	<u>Cost-Year Cents/Ton Mile</u>	<u>Cost-Year \$10/year</u>	<u>1981^(a) \$10/Year</u>
Anderson and Rogozen ^(b)	1977	0.73	180	250
Armbruster and Candela	1976	0.51 ^(c)	130	180
Campbell and Katell ^(d)	1975	0.3 to 0.7	80 to 170	125 to 250
Hyde	1979	0.51 ^(c)	130	150
Sargent	1976	0.51 ^(c)	130	180
Equations 3.29 and 3.31 ^(b,e)	1981		250	250

(a) Adjusted using Oil and Gas Journal Oil Pipeline Cost Index.

(b) Assumes fixed cost rate of 0.15.

(c) Presumably these estimates were derived from the same source.

(d) Maximum capacities of 6 million tons per year considered for this study.

(e) Assumes 15 pump stations; power cost of 30 mills/kWh; capacity factor of 100%.

As with any development, some environmental effects are associated with coal slurry pipeline construction. The land requirements for the pipeline right-of-way were reviewed in the previous section. Construction activities require the removal of vegetation, trenching, destruction of wildlife habitat possibly affecting local animal populations, and increased traffic by trucks and construction equipment hauling and stringing the pipe. Exhaust emissions from equipment and wind-blown dust from exposed soil contribute to air pollution. Erosion from exposed soil and burial beneath river beds causes siltation in waterways, which can have harmful effects on fish and other aquatic wildlife. Construction activities create noise and detract from the aesthetic quality of the immediate vicinity. All of these problems are short-lived; because construction moves quickly, the pipe is buried and the exposed soil is revegetated. Most of the environmental effects from construction can be reduced or eliminated if proper precautions are taken and if mitigating strategies are employed.

In normal operation, coal slurry pipeline imposes far less impact on the environment than do unit trains. During the operational phase the most severe environmental problem is the potential for a pipe rupture, which would spill slurry onto productive farmland or sensitive ecological areas. The chances of such an event occurring and the area affected are both small. The most significant operational environmental effect is water use. Without water, a water-coal slurry cannot be produced and pipeline transport cannot proceed. Water requirements are discussed in the preceding section. Water availability could be a limiting factor in the development of coal slurry pipelines in the semi-arid West. Rogers (1980) addresses the problems of water use and coal slurry pipelines in more detail.

Other operational environmental effects of coal slurry pipelines include noise and aesthetic degradation from terminals and pump stations. However, these effects would be minor if the facilities were located in remote areas. Indirect environmental effects of Coal Slurry pipeline operation include increased air and water pollution at electrical power plants that supply the power for pipeline operations.

Wastewater Discharge

The coal slurry must be dewatered at the power plant terminal. The water extracted from the slurry must be treated to achieve acceptable water quality prior to discharge. Also, potential water quality problems must be resolved prior to discharge. A portion of the slurry water may be used as part of the makeup water at the power plant.

Accident Rates

Coal slurry pipelines are safer than rail transport even when accidents occurring during pipeline construction are considered. Estimated accident rates for slurry pipeline transportation of coal are 3.45×10^{-8} fatalities and 5.8×10^{-8} nonfatal injuries (with 0.24 man-days lost per occurrence) for every ton of coal transported (Bliss et al. 1977).

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4.0 COAL-BASED GASIFICATION SYSTEMS FOR ELECTRIC POWER PRODUCTION

One option for producing electric power from coal is to convert the coal to a clean gaseous fuel and then use the gas for power production. This option has several potential advantages. The gas produced from coal is, in many ways, superior to coal as a fuel. The gas is cleaner and easier to use and in some cases cheaper to transport. In addition, using the gas has much greater flexibility than using coal. For example, fuel gas produced from coal can be used to power gas turbines or fuel cells, whereas the raw coal cannot be used in these devices.

The gasification option involves several technologies, including gasification, pipeline transport of the gas, and use of the gas in power production. In the following sections, each of these technologies will be addressed. Gasification in a facility dedicated to that purpose will lead the discussion. This will be followed by discussions of pipeline transport, use of the gas in a combined-cycle power plant and the combination of gasifier and power plant in an integrated gasifier - combined-cycle power plant. Each section contains a brief introduction to the technology and a discussion of economic, environmental, and resource factors.

4.1 COAL GASIFICATION FACILITY

Coal gasification provides a method of converting coal from a relatively dirty and cumbersome solid fuel into a clean, convenient gaseous fuel. In the coal gasification process, fuel gases are produced by partial oxidation and/or hydrogenation of the solid coal at elevated temperature and usually at elevated pressure. After purification, the gas may be used directly as a fuel or chemical feedstock, converted to an upgraded gaseous or liquid fuel, or used to produce electric power. Although coal gasification has been practiced commercially for many years, only a few small-scale plants are presently operating in the United States. The gasification process is described in the following sections.

4.1.1 Coal Gasification Process

Commercially available coal gasification processes operate by reacting the coal with steam and oxygen (or air) at elevated temperatures (above 1300°F). The reactive portion of the coal consists primarily of carbon with lesser amounts of hydrogen, oxygen, sulfur and nitrogen. These components are converted to a gas by oxidation, hydrogenation and thermal cracking. Many reactions may occur during gasification. A consideration of the reactions of carbon gives some insight into the thermodynamic constraints that govern the gasification process.

Carbon may be oxidized by O_2 , H_2O or CO_2 via the following reactions:

Carbon can also be converted to methane (CH_4) by reaction with hydrogen or steam:

Because of the heat absorbed by reactions (4.3) and (4.4), usually heat must be supplied by adding oxygen, which promotes exothermic reactions (4.1) and (4.2).^(a) If dilution of the product gas with nitrogen is acceptable for a given application, the oxygen can be supplied as air; if not, an air separation

(a) In some developmental processes, this requirement has been eliminated either by suppressing the endothermic reactions or by using other sources of heat.

plant is typically required to supply pure oxygen. High-molecular-weight hydrocarbon constituents decompose at high temperatures producing light hydrocarbons, tars, oils, CO_2 , H_2O , char, and other products. The hydrogen, oxygen, sulfur and nitrogen in the coal also react, producing H_2S , COS , CO_2 , NH_3 , HCN , H_2O , and other trace components.

If air is used, a low-grade gas is produced with a heating value of approximately 100 to 150 Btu per standard cubic foot (scf). This gas is generally referred to as low Btu gas (LBG). If oxygen is used, the gas heating value is higher at 250 to 350 Btu/scf. This gas is commonly referred to as intermediate Btu gas (IBG). The fuel value of the gas results primarily from the H_2 , CO and CH_4 content with some contribution from other light hydrocarbon gases.

Heating values and typical gas concentrations of the primary fuel gas constituents are shown in Table 4.1. Most of the gas heating value results from the H_2 and CO , which have a relatively low heating value per unit volume. Methane (CH_4) and ethane (C_2H_6) have much higher heating values, but their concentrations are relatively low. The heating value per unit volume of the gas can be substantially increased by converting the H_2 and CO to methane ("methanation") by the following reaction:

These reactions are typically carried out at 500 to 900°F in the presence of a catalyst. If, as is usually the case, the gas does not contain sufficient hydrogen for reaction (4.7), additional H_2 is produced by reaction (4.8), the water gas shift reaction (again in the presence of a catalyst).

By using reactions (4.7) and (4.8) nearly all of the H_2 and CO content of the gas can be converted by CH_4 , steam and CO_2 . The steam and CO_2 can be removed by condensation and absorption, respectively. The remaining gas will

TABLE 4.1. Heating Values of Primary Fuel Gas Constituents

Typical Fuel Gas Properties			Typical Concentration Mole (Dry Basis)	
Gas Component	HHV ^(a) Btu/scf	LHV ^(b) Btu/scf	Air Blown(%)	Oxygen Blown(%)
H ₂	343	289	8-20	24-40
CO	339	339	4-30	15-65
CH ₄	1069	961	trace-4	trace-10
C ₂ H ₆	1890	1727	1	trace-1
CO ₂	0	0	3-12	3-30
N ₂	0	0	45-60	trace-2

- (a) Higher heating value (gross heating value): heat of combustion, including heat released by condensing the water vapor produced. Basis 359 scf/lb Mole.
- (b) Lower heating value (net heating value): heat of combustion, excluding heat released by condensing water vapor produced.

be principally CH₄^(a) with small amounts of H₂, CO, CO₂, N₂, light hydrocarbon gases and sulfur compounds. This gas has a heating value of approximately 1,000 Btu/scf and, with adequate water, CO, CO₂, and sulfur compound removal, it is directly interchangeable with natural gas.^(b) This high heating value gas is generally referred to as high Btu gas or substitute natural gas (SNG).

When the product gas must be transported over long distances prior to use, the high energy concentration in SNG gives it a significant advantage over LBG and IBG. Another advantage of SNG is its direct interchangeability with natural gas; it can be used in the existing pipeline transmission and distribution network and in end-use equipment designed for natural gas.

Whereas SNG is a preferred fuel product for some applications, conversion of IBG to SNG adds considerably to the cost of the product gas. If reactions (4.7) and (4.8) are used, 23% of the net heating value of the H₂ and CO is converted to heat. Much of this heat can be recovered and used. However, the

(a) Assuming oxygen-blown gasification.

(b) See Detman (1976) p. 8 and pp. 24-29 for pipeline gas specifications.

overall effect is to reduce thermal efficiency and to increase capital and operating costs. Additional gas cleanup costs are incurred in producing SNG because of the very low sulfur concentration required to avoid poisoning the methanation catalyst. Additional purification is also required to remove CO_2 from the gas.

In many of the advanced gasification processes being developed for SNG production, an effort is made to increase the concentration of CH_4 in the raw gas produced by the gasifier, thereby reducing the amount of waste heat produced. Increasing the CH_4 produced also reduces the oxygen consumption in the gasifier. Methods used to increase the CH_4 yield include increased pressure, reduced temperature, and rapid heating of pulverized coal in the presence of hydrogen.

In addition to the primary product (i.e., gaseous fuel), coal gasification processes produce several by-products. The number and quantity of by-products produced depend on the particular process and coal used. Possible by-products include elemental sulfur or sulfuric acid, ammonia, tars, oils, phenols, char, steam, and electric power.

Although many coal gasification processes exist, most have a similar sequence of process steps. Major steps in the coal gasification process include coal preparation, coal feeding, gasification, gas cooling, gas purification, waste water treatment, by-product separation and recovery, steam generation, and oxidant feed. These steps are illustrated for IBG and LBG in Figure 4.1. General descriptions of the major process components required for low, intermediate and high Btu gas production are presented in the following section.

Coal Preparation

Coal preparation consists mainly of crushing, grinding and sizing operations and, in some cases, drying. Requirements vary greatly depending on the type of gasifier used. Typical gasifier feed requirements range from 1-1/2 in. x 1/8 in. undried coal for the Lurgi fixed-bed gasifier to predried coal

FIGURE 4.1. Low and Intermediate Btu Gas General Process Flow Sheet

pulverized to 70% passing a 200 mesh for entrained-flow gasifiers. Some bituminous coals tend to swell and become sticky when heated. Agglomeration of these sticky coal particles can cause serious operating problems with certain gasifiers. To avoid these problems, the coal sometimes must be preheated to reduce its tendency to agglomerate.

Coal Feeding

Dry feeding is generally accomplished using a double-valved lockhopper. With the discharge valve closed, the lockhopper is charged with coal. The coal feed valve is then closed, and the hopper pressurized with a purge gas. The bottom (discharge) valve is then opened, allowing the coal to flow out. The bottom valve is then closed, the hopper depressurized, the top valve reopened and the hopper recharged with coal. The coal may fall directly into the gasifier or may fall into a feed hopper. From the feed hopper the coal can be fed into the gasifier with a screw feeder or pneumatic feeder.

Slurry feeding may also be used, particularly at higher pressures. Coal is slurried with water or a recycle oil and pumped into the gasifier.

Gasification

Types of gasification reactors used for coal include fixed (or slowly moving) bed, fluidized-bed, entrained-flow, "fast fluid-bed," tumbling-bed, and molten-bath. In short, virtually every reactor type imaginable for carrying out a gas/solid reaction has been tried for coal gasification. It is not the purpose of this study to discuss the details of the various gasifier types. The interested reader should consult the voluminous literature available for more details on this subject (for example, Dravo 1976 or Lowery 1963).

In general the purpose of the gasifier is to convert the fuel value of coal from solid to gaseous form. This is usually accomplished by reaction with steam and oxygen. In some processes oxygen is not used, in which case steam, hydrogen, and/or carbon monoxide are reacted with the coal (e.g., Exxon catalytic gasification process (Epperly and Siegel 1976) or CO₂ acceptor process (Dravo 1976)].

Depending on the gasification process, reaction temperatures may range from about 1,300 to over 3,000°F. At the lower temperatures (less than about 1,700°F) tars and oils are produced. At the higher temperatures (greater than about 2,200 to 2,500°F depending on feed coal) the ash fuses, forming a liquid slag. Operating pressures vary between atmospheric and 1,000 psi or more. Elevated pressure tends to increase methane production and to reduce equipment size. Operation at elevated pressure is also desirable when the product gas is required to be at an elevated pressure (e.g. as feed to a gas turbine or to a pipeline).

An example of a commercially available gasification reactor is the Lurgi gasifier shown in Figure 4.2. This gasifier is classified as a high-pressure (300 to 500 psig) fixed-bed, nonslagging gasifier. It is a double-walled pressure vessel with the walls forming a water jacket for protection of the outer pressure vessel wall from high-reaction temperatures. Some steam is also produced in the jacket and can be used elsewhere in the process. Feed coal enters at the top through a lockhopper system and is distributed on top of the bed by

FIGURE 4.2. Lurgi Gasification Reactor

a rotating arm. Near the bottom of the inside shell a grate supports the coal bed. The coal gradually moves downward as steam and oxygen (or air) flow upward through it. The grate rotates, allowing spent fuel (ash) to fall into a lower lockhopper, from which it is subsequently discharged.

Combustion and gasification reactions occur in the bottom portions of the bed. Sufficient steam is added to prevent melting or clinkering of ash in this zone. Drying and pyrolysis occur in upper portions of the bed as the coal is heated by hot gases. Crude gas leaves the gasifier at 750 to 1100°F and is scrubbed in a washer/cooler with recycled gas liquor.

The Lurgi gasifier has been available commercially since 1936. Several Lurgi gasification plants are operating worldwide, although none exist in the United States. A typical 12 ft ID gasifier can process approximately 800 tons/day of coal.

The BGC slagging gasifier is similar to the Lurgi design except that the bottom has been modified to allow operation with molten ash (slag). Much lower steam rates are used, allowing the temperature near the bottom of the gasifier to increase to about 3,500°F. This reactor is not commercially available at present but has undergone successful pilot tests. The BGC slagging gasifier is but one of many advanced gasifiers being developed to improve the economics of coal gasification. Major advantages of the BGC gasifier include higher reaction rates and higher capacity per gasifier, low steam consumption, modest oxygen consumption and low water content in the product gas, which reduces the amount of condensate requiring treatment.

Gas Cooling

Prior to purification, gas must be cooled from the gasifier outlet temperature (750 to 1800°F or higher) to the operating temperature of the scrubber systems used for cleaning the gas (250°F). The type of cooling used depends primarily on the tar content of the gas. If significant quantities of tar are present, recycled condensate is injected to rapidly cool or "quench" the gas. The quench condenses heavy tars and removes most of the particulate matter. The gas may then enter a waste heat boiler to produce low-pressure steam or may be subjected to a lower temperature quench or scrubbing step. If the raw gas from the gasifier is free of tars, most of the sensible heat of the gas may be recovered by waste heat boilers, producing high-pressure steam. After the gas has been partially cooled by heat exchange, it is scrubbed with water. This completes the cooling and removes particulate and other impurities.

Gas Purification

The extent of gas purification required depends on the downstream process and end-use requirements. If gas is to be upgraded to SNG, the sulfur content must be reduced to a low level to avoid damage to the conversion catalyst. Use in gas turbines requires a very low level of particulate and alkali metals. Environmental regulations will typically require removal of at least some of the sulfur compounds and ammonia from the gas to minimize release of SO₂ and NO_x, respectively.

In a typical purification process, particulate, condensible organic (principally tars, oils and phenols), and condensate water are removed first. The majority of the particulate may be removed dry using a cyclone or it may all be removed with the liquids. Various impurities are dissolved or suspended in the condensate water. These impurities may include phenols, organic acids, CN^- , CNS^- , inorganic salts, trace metals and dissolved gases (NH_3 , H_2S , CO_2 , etc.).

Ammonia is removed from the gas by countercurrent scrubbing with water. The water used may be a recycled process condensate. The sour water stream produced may be processed for anhydrous ammonia production.

After ammonia removal, sulfur compounds (and in some cases CO_2) are removed from the gas. Production of LBG or IBG gas for direct fuel use generally requires a relatively modest sulfur removal efficiency (~90%), and CO_2 removal is not usually required (although a portion of it is unavoidably removed in many sulfur removal processes). If the gas is to be subsequently upgraded to SNG (or liquid fuels), the sulfur removal requirement is much more stringent (typically 99.9%), and CO_2 must also be removed.

Sulfur compounds (principally H_2S and COS) are removed by scrubbing the gas with either a solvent that dissolves the gases (physical absorption processes) or with a chemical solution that reacts with the gases (chemical absorption processes). In most processes at least some of the CO_2 is also removed. Processes for removal of H_2S and CO_2 are collectively referred to as "acid gas removal processes." Most of the many processes available for this application can reduce the H_2S concentration to low levels. However, removal efficiency for COS and other sulfur compounds varies considerably.

Typical solvents used in physical absorption processes include methanol (Rectisol process), polyethylene glycol dimethyl ether (Selexol process), and propylene carbonate (Fluor solvent process). Typical active solutes used in chemical absorption processes include mono and diethanol amines, other alkanol amines, and potassium or sodium carbonate. The solutions are regenerated by stripping, heating, and/or pressure reduction, or in some cases by oxidation of the sulfur content to elemental sulfur, which is removed as a froth. The product gas from solvent regeneration contains a high concentration of H_2S .

This stream can be fed to one of several available sulfur recovery processes that oxidize H_2S to water and elemental sulfur. Tail gas from sulfur recovery may require additional cleanup and conversion of residual tracts of sulfur compounds to SO_2 (by incineration), after which the remaining gases are vented. For processes that require a very low residual sulfur content in the product gas, a bed of zinc oxide may be used after the primary sulfur removal step. This absorbent is not regenerable and therefore requires periodic replacement. Several publications give details of acid gas and ammonia removal processes for coal gasification applications: Dravo 1976; Ghassen 1978a, 1978b; Murthy et al. 1977; and Fleming and Primak 1977.

After purification, the gas is generally ready for end use, distribution or upgrading. In some cases, additional process steps might be required (e.g., drying or pressure adjustment to suit a particular end-use or distribution system requirement).

Upgrading to SNG

Many of the process steps required for SNG production are identical or very similar to those required for LBG or IBG gas production, as described above. A generalized flowsheet for SNG production is shown in Figure 4.3. This flowsheet fits all conventional and most advanced processes. The major differences between this flowsheet and Figure 4.1 (flowsheet for LBG, IBG) are the shift conversion step and the methanation step. In the shift conversion step the H_2/CO ratio is adjusted to approximately 3.5:1 as required for the methanator feed. A small excess of H_2 is used, resulting in a low residual CO concentration (0.1 mole %) required by pipeline gas specifications. In the methanation reactor H_2 and CO are converted to methane. Some other process steps may be modified somewhat for SNG production. The gas purification system must provide more efficient sulfur compound removal and CO_2 removal is also required. The gasifier design may be modified to increase methane yield.

4.1.2 Coal Gasification Economics

Due to the early development stage of coal gasification in this country, system costs are difficult to estimate accurately. Commercial coal gasification plants are limited to a few foreign operations that typically serve a

FIGURE 4.3. SNG Production From Coal - Generalized Flow Sheet

different purpose than is under consideration here (e.g., production of a synthesis gas for fertilizer or chemical production). A few units are operating in this country, but they are very small and bear little resemblance to commercial operations that are required to economically produce utility fuel gas.

The ability to provide a generic cost or performance estimate for coal gasification plants is hampered by the many different systems available or proposed, different types of feed coal, and various site-specific factors that can have a significant effect. Rather than provide a generalized cost figure, published capital and operating cost estimates were compiled for several systems for comparison. Most of these estimates were made using factored cost-estimating techniques. The level of detail in these studies is somewhere between the "preliminary estimate" and "study estimate" as defined by Peters and Timmerhaus (1968, pp. 95-99). The accuracy of this type of estimate is typically no better than ± 20 to 30%. In the case of developmental processes where little data are available, estimates may not even be that good.

Another problem with evaluation of coal gasification economics is the production of substantial quantities of by-products. The marketability and value of these by-products are uncertain. This uncertainty makes standardized comparisons based on capital and operating cost per unit of output more difficult to make and less meaningful.

Low and Intermediate Btu Gas

To obtain approximate costs for LBG and IBG gas production, several recent design studies were reviewed. Table 4.2 gives a summary of published economic and operating parameters for several of the processes covered by these design studies. Columns 1 through 5 give results of studies performed by Fluor and sponsored by the Electric Power Research Institute (EPRI). Columns 6 and 7 give results of a DOE-sponsored study, published by Stanford Research Institute, and Columns 8 and 9 give results of a study made by Dravo Corporation.

In addition to these studies, various "typical gas costs" are quoted by several sources. Examples include \$3.75 to \$4.50/10⁶ Btu quoted by DOE (Bardos et al. 1978), \$4.00/10⁶ Btu quoted by Memphis Light, Gas, and Water (Gray 1978) and \$3.25 to \$3.75 reported by the National Research Council (NRC 1977a).

TABLE 4.2. Low and Intermediate Btu Gas, Published Economic and Operating Characteristics Summary

Reference	1 (Chandra et al. 1978a)	2 (Chandra et al. 1978a) (Kimmell et al. 1976)	3 (Chandra et al. 1978a) (Kimmell et al. 1976)	4 (Chandra et al. 1978a) (Kimmell et al. 1976)	5 (Chandra et al. 1978a) (Kimmell et al. 1976)	6 (SRI 1978)	7 (SRI 1978)	8 (Ferretti 1976b)
Gasifier Type	Fixed Bed Slagging	Fixed Bed	Fixed Bed	Fluid Bed	Fluid Bed	Advanced Technology High Pressure	Advanced Technology High Pressure	
Gasifier Make Status	B.G.C. Pilot	Lurgi Commercial	Lurgi Commercial	U-Gas Pilot	U-Gas Pilot			
Gas Produced	Intermediate Btu	Intermediate Btu	Low Btu	Intermediate Btu	Low Btu	Intermediate Btu	Intermediate Btu	Intermediate Btu
Gas Heating Value	379	302	179	323	158			310
<u>Coal Feed</u>								
Coal Type	Bituminous	Bituminous	Bituminous	Bituminous	Bituminous	Sub-Bituminous	Bituminous	
Coal Feed Rate (Ton/Day)	10,000	10,000	10,000	10,000	10,000	9700	7950	14,200
Coal Feed HHV -	244.7	244.7	244.7	244.7	244.7	160	171	
Coal Sulfur Content	3.7%	3.7%	3.7%	3.7%	3.7%	Low	High	
<u>Products</u>								
Product Gas HHV - (10 ⁹ Btu/Day)	197	132	134	201.4	184.9	120	120	250
Oil and Tar (Ton/Day)	0	21.9x10 ⁹	21.9x10 ⁹	0	0	ND	ND	
Phenols (Ton/Day)	0	Btu/Day	Btu/Day	0	0	ND	ND	
Ammonia (Ton/Day)	111	111	111	6	10	ND	ND	
Sulfur (Ton/Day)	284	278	269	304	305	ND	ND	
Byproduct Power (MW)	12.8	63.7	76.4	50.2	72.5	ND	ND	
Other								
<u>Water Requirements</u>								
Raw Water Feed Ton/Day	13,000	44,400	39,700	23,000	31,700	ND	ND	
Raw Water Feed Acre Ft/Yr								
<u>Published Economics</u>								
Cost Base Date	Mid-1976	Mid-1976	Mid-1976	Mid-1976	Mid-1976	Mid-1976	Mid-1976	1975
Capital Cost \$10 ⁶	303	550.5	454	356.7	368	ND	ND	
Total Capital								
Excluding Coal	392	705	584	460	475	275.5	306.3	
Operating Cost -								
Excluding Coal \$10 ⁶ /yr	23.8	45.9	35.2	28.5	29.4	31.5	34.7	
Byproduct Credit	7.5	21.1	24.5	13.6	19.8	ND	ND	
Calculated Gas Cost -								
Excluding Coal \$/10 ⁶ Btu	1.20	2.67	2.01	1.31	1.38	1.91	2.12	~1.25
Assumed Coal Cost \$/10 ⁶ Btu HHV	1.00	1.00	1.00	1.00	1.00	0.605	0.929	~1.00
Calculated Gas Cost								
Including Coal	2.44	4.26	3.57	2.52	2.70	2.72	3.45	2.70
Thermal Efficiency ^(a)	8.3%	68.3%	70.4%	85.1%	79.7%	75%	70%	~70%

(a) [Prod. Gas HHV + Prod. Liquid HHV + Net Electric Production (9000 Btu/kWh)] ÷ (Feed Coal HHV)

Where sufficient information is given in the published reports, the data shown in Table 4.2 are relatively consistent. In some cases all of the assumptions used in making cost estimates were not reported. All feed and product rates shown are design basis or 100% operating rate basis. The cost figures are based on average annual production at 90% of design (i.e., 90% capacity factor). In some cases the economics are also presented at other capacity factors in the original references (e.g., 70% in the Fluor-EPRI studies). Figures given as "capital cost" are total estimated design and construction costs, including general and offsite facilities. The total capital required includes the capital cost plus sales tax, working capital, startup costs, interest during construction, and initial catalyst and chemical requirements. Operating costs include labor, materials (other than coal), utilities, various overheads, and in some cases other miscellaneous costs (e.g., ash disposal charge). The calculated gas cost shown in Table 4.2 is as reported in the original reference and may not be directly comparable among different authors.

The information presented in Table 4.2 has several limitations. The various studies assume plants of different size, so capital and operation costs between studies are not directly comparable. The amount of by-products produced varies considerably among processes, so direct comparison among different processes with the same design basis gas production rate or coal feed rate may be somewhat difficult. Researchers may treat these problems in various ways that can affect the bottom line gas cost. Besides the effect of plant capital and operating costs, calculated gas cost can be altered substantially by changing financial assumptions and assumed average operating rate.

In the Fluor-EPRI studies, by-products are handled in two ways (Chandra et al. 1978a, 1978b; Coleman et al. 1979). The value of the ammonia and export power produced is treated as credits against operating costs. Tars, oils and phenols produced are treated as a fuel product with the same value as the gas produced. A fixed charge rate of 15.6% was used in the Fluor-EPRI studies. This is the annual capital recovery required to cover depreciation, bond interest, return on investment, and income taxes. A fixed charge rate of 16% was used in the SRI study; however, this rate also includes local taxes and insurance. Local taxes and insurance were included in the operating costs of the Fluor-EPRI studies and were calculated as 2.5% of capital cost or approximately

2% of total capital required. Therefore, on a basis comparable to the Fluor-EPRI studies, the capital charge rate on the SRI studies is 14%. Local taxes and insurance at 2% of total capital have been subtracted from operating costs reported by SRI and are shown as a separate item in Table 4.2.

Calculated gas costs shown in Table 4.2 vary between $\$1.20/10^6$ Btu and $\$2.67/10^6$ Btu, not including the cost of feed coal. With delivered coal costs of $\$1.00/10^6$ Btu, calculated gas costs increase to $\$2.44$ to $\$4.26/10^6$ Btu. The higher costs shown are for the commercially available process, whereas the lower costs shown are for the development processes. There is a fair agreement among authors, although costs predicted by SRI and Dravo appear to be a little higher and lower, respectively, than those reported in the Fluor-EPRI studies. These cost figures also show that for the large integrated plants assumed in these studies, the use of oxygen rather than air blown gasification has only a small effect on gas cost because the cost of the oxygen plant is partially offset by reductions in gas cleanup and compression costs.

To reduce the cost data into a useful form for this study, several economic and operating factors were calculated from data in Table 4.2 and are listed in Table 4.3. Information on costs and feed rates are given per Btu of product or per annual Btu capacity. For these calculations, by-products are handled in the same way as the Fluor-EPRI studies. All costs except the by-product credit have been escalated to 1981 dollars using the Chemical Engineering plant cost index. The by-product credit is as originally reported.

Total capital costs include plant capital costs, interest and escalation during construction, working capital, startup costs and initial charge of catalysts and chemicals. Interest and escalation during construction was based on a three-year construction period, 12.5% interest, 8.5% escalation and a payout schedule of 25%, 50%, 25% for years 1, 2, 3, respectively. Due to the lack of accurate information on working capital, startup costs, and initial charge of catalysts and chemicals, these costs were collectively estimated at 6% of plant capital costs.

Several conclusions can be drawn from inspecting the figures listed in Table 4.3. Examination of cost components shows that nearly all of the product gas cost results from capital charges and feed coal cost. With the selected

TABLE 4.3. Low and Intermediate Btu Gas - Standardized Unit Cost and Performance Summary

Column No. Reference	1 (Chandra et al. 1978a) F.B. Slagging Bituminous	2 (Chandra et al. 1978a) (Kimmell et al. 1976) Lurgi-O ₂ Sub-Bituminous	3 (Chandra et al. 1978a) (Kimmell et al. 1976) Lurgi-Air Bituminous	4 (Chandra et al. 1978a) (Kimmell et al. 1976) U-Gas-O ₂ Bituminous	5 (Chandra et al. 1978a) (Kimmell et al. 1976) U-Gas-Air Bituminous	6 (SRI 1978) Advanced Subminous	7 (SRI 1978) Advanced Bituminous	8 (Ferretti 1976b)
Gasification Process Coal Type								
Rates Based on Fuel Produced (Gas and Liquid Hydrocarbons)(a)								
Coal Feed Btu/Btu Prod.	1.242	1.590	1.570	1.215	1.323	1.333	1.429	~1.43
Raw Water Feed Ton/10 ⁹ Btu Prod.	66	288	255	114	171	ND	ND	
Oil, Tar and Phenols, Btu/Btu Prod.	0	0.14	0.140	0	0	ND	ND	
Capital and Operating Costs at 90% Operating Rate (1981 \$) (b)								
Capital Cost \$/10 ⁶ Btu Prod./yr	6.79	15.78	10.76	7.81	8.77	ND	ND	
Total Capital \$/10 ⁶ Btu Prod./yr(c)	9.62	22.36	15.25	11.07	12.43	10.14	11.26	
Operating Cost \$/10 ⁶ Btu Prod.(d)	0.533	1.316	0.835	0.625	0.702	1.158	1.275	
By-Product Credit \$/10 ⁶ Btu Prod.(e)	0.176	0.417	0.401	0.206	0.326	ND	ND	
Capital Charge @ 15.3%/yr \$/10 ⁶ Btu Prod.	1.472	3.421	2.333	1.694	1.902	1.551	1.723	
Contribution of Coal Cost to Gas Cost								
Coal Cost @ \$0.50/10 ⁶ Btu, \$/10 ⁶ Btu Prod.	0.621	0.795	0.785	0.608	0.662	0.667	0.715	
Coal Cgst @ \$1/10 ⁶ Btu, \$/10 ⁶ Btu Prod.	1.242	1.590	1.570	1.215	1.323	1.333	1.429	
Coal Cgst @ \$1.50/10 ⁶ Btu \$/10 ⁶ Btu Prod.	1.863	2.385	2.355	1.823	1.985	2.000	2.144	
Total Gas Cost with Selected Cost Factors: Capital Charges @ 15.3%/yr and Coal @ \$1/10 ⁶ Btu								
Total Gas Cost \$/10 ⁶ Btu	3.13	5.91	4.34	3.33	3.60	4.04	4.43	

(a) All rates based on higher (gross) heating value.

(b) All costs escalated 1981 dollars using the Chemical Engineering plant cost index. All costs assume a 90% operating rate.

(c) Total capital includes plant capital cost, interest during construction, escalation during construction, working capital, startup costs, and initial charge of catalyst and chemicals.

(d) Operating costs include labor, materials (except coal), utilities, ad valorem taxes and insurance, and miscellaneous charges and overhead.

(e) By-product credit has been treated as a saleable item and credited against operating costs in calculation of total gas cost.

ND No data or insufficient data.

capital charge rate of 15.3% and coal at \$1/10⁶ Btu, these two factors account for about 80% of total gas cost in most cases. Total gas cost estimates range from \$3.13 and \$5.91/10⁶ Btu. If this gas were used for power production, the cost of fuel alone would contribute between 31.3 and 59.1 mills/kWh to the total power generation cost, using the selected cost assumptions and assuming a heat rate of 10,000 Btu/kWh. Transportation costs will increase this further. Comparison of this cost with total cost of power generation by conventional coal-fired systems shows that use of the gas to produce electricity will be a relatively expensive option unless the heat rate can be reduced to well under 10,000 Btu/kWh.

Substitute Natural Gas

Accurate estimation of capital and operating costs for SNG production is hampered by the same problems encountered with LBG and IBG (i.e., lack of large-scale commercial experience and sketchy performance data on developing gasification processes). In addition, advanced reactor designs that yield the lowest cost estimates are more complicated than the advanced designs for IBG production. Because of this, technical problems and scaleup uncertainties are greater and hence the accuracy of the estimate may be lower than for IBG processes. The increased complexity and more severe conditions to which materials and equipment are exposed in the advanced processes may affect the maximum attainable capability factor. The capacity factor is a key factor in total gas cost because of high fixed costs of SNG production. Because a relatively high level of interest has existed in SNG production within both the government and industry, many design studies that contain cost information are available. A summary of selected published cost and performance estimates for large coal-based SNG plants is shown in Table 4.4.

Columns 1 through 10 and 16 in Table 4.4 give information for plants using Western subbituminous coal or lignite, while columns 11 through 15 pertain to high sulfur bituminous coals. The majority of these studies were performed by C. F. Braun and Co. under joint DOE/American Gas association sponsorship; others were performed by C. E. Lummus, Argonne National Laboratory, and Wyoming Coal Gas Co. Figures recently quoted by the Gas Research Institute (GRI) are given in column 17. No information was provided for the basis of the GRI figures.

TABLE 4.4. High Btu Gas Production - Summary of Published Performance and Cost Estimates

Column No. Gasifier Type Gasifier Make Status Location Assumed	1 Fixed Bed Lurgi Commercial West	2 Fixed Bed Lurgi Commercial Wyoming	3 Fixed Bed Lurgi Commercial N. Dakota	4 Fixed Bed Lurgi Commercial N. Dakota	5 Fluid Bed Hygas-O ₂ Pilot West	6 Fluid Bed Hygas-Fe Pilot West	7 Entrained Bigas Pilot West	8 Fluid Bed Synthane Pilot West	9 Fluid Bed CO ₂ Acceptor Pilot West	10 Fluid Bed CO ₂ Acceptor Pilot N. Dakota	11 Fluid Bed Lurgi Commercial East-Central	12 Fluid Bed Hygas-O ₂ Pilot East-Central	13 Fluid Bed Hygas-Fe Pilot East-Central	14 Entrained Bigas Pilot East-Central	15 Fluid Bed Synthane Pilot East-Central	16 Fluid Bed Synthane Pilot ND	17 ND ND ND
Coal Feed																	
Coal Type	Sub-Bitum.	Sub-Bitum.	Lignite	Lignite	Sub-Bitum.	Sub-Bitum.	Sub-Bitum.	Sub-Bitum.	Sub-Bitum.	Lignite	Bituminous	Bituminous	Bituminous	Bituminous	Bituminous	Rosebud	Coal
Coal Feed Rate (ton/day)	24,300	27,200	30,500	38,800	20,470	22,830	23,000	27,860	20,700	27,800	18,300	15,900	21,444	14,960	18,140	26,000	NO
Coal Feed HHV (10 ⁹ Btu/day)	431	460	409	529	360	402	399	491	386	375	454	393	532	371	450	430	ND
Coal Sulfur Content	0.66%	ND	0.8%	1.6%	0.66%	0.66%	0.66%	0.66	0.66	0.8%	4.4%	4.4%	4.4%	4.4%	4.4%	0.8%	ND
Products																	
Product Gas HHV (10 ⁹ Btu/day)	250	250	250	283	250	250	250	250	250	250	250	250	250	250	250	250	250
Oil and Tar (ton/day)	1,360	808	982	1,246	631	354	0	721	0	0	232	415	341	0	600	0	ND
Phenols (ton/day)	140	115	103	144	ND	ND	0	ND	0	0	44	0	0	0	0	0	ND
Ammonia (ton/day)	140	101	184	269	89	105	92	86	70	98	123	92.4	139	110	161	180	ND
Sulfur (ton/day)	96	62	125	594	100	90	108	119	101	120	696	610.8	668	674	701	173	ND
Electric Power (MW)	0	0	0	0	0	193	0	0	60.5	0	0	0	645	0	0	0	ND
Other Amount								Char 1,840 ton/day							Char 1,024 ton/day	Char 1,277 ton/day	
Water Requirements																	
Raw Water (ton/day)	14,600	19,860 to 32,400	43,930	72,000	11,400	20,344	12,940	13,060	13,630	32,270	66,420	49,700	70,524	44,270	47,000	76,800	23,460
Raw Water (acre ft/yr)																	
Published Economics																	
Cost Base Date	1/76	ND	1/76	1975	1/76	1/76	1/76	1/76	1/76	1/76	1/76	1/76	1/76	1/76	1/76	1977	1978
Capital Cost, \$10 ⁶	1,047	ND	1,030	878	870	1,280	1,030	1,150	890	930	1,170	930	1,260	880	1,010	987	ND
Interest During Con- struction, \$10 ⁶	165	ND	173.81	77.0	137.02	201.60	162.22 ^(a)	181.12 ^(a)	140.18 ^(a)	156.94	197.44 ^(a)	156.94 ^(a)	212.63 ^(a)	148.50 ^(a)	170.44	155.5	ND
Startup Costs, \$10 ⁶	55	ND	41.93	120.2	34.98	49.64	40.47	41.08	41.47	36.25	76.44	52.33	71.52	52.51	57.52	33.31	ND
Working Capital, \$10 ⁶	26	ND	22.44	120.2	20.46	28.99	23.85	26.86	22.97	21.86	33.73	27.58	37.18	26.06	30.38	22.08	ND
Total Capital Required, \$10 ⁶	1,293	ND	1,268	1,076	1,065	1,564	1,257	1,399	1,098	1,145	1,478	1,167	1,581	1,107	1,268	1,198	ND
Operating Cost Excluding Coal, \$10 ⁶ /yr	65.9	ND	47.01	52.0 ^(a)	49.69	83.18	58.06	58.18	76.97	62.63	57.75	57.3	54.82	40.70	41.95	60.94	ND
By-Product Credit, \$10 ⁶ /yr	44	ND	35.5	ND	28.9	24.9	5.0	22.4	8.9	6	20.5	25.1	151.34 ^(c)	10.8	35.2	11.8	ND
Local Taxes and Ins., \$10 ⁶ /yr	88.3	ND	15.45	ND ^(b)	23.49	34.56	27.81	31.05	24.03	13.95	17.55	13.95	18.90	13.20	15.15	26.65	ND
Assumed Capital Charge, Rate/yr	12%	ND	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	ND
Calculated Gas Cost Excluding Coal, \$/10 ⁶ Btu	2.49	ND	2.18	--	2.10	3.15	2.82	2.86	2.72	2.54	2.83	2.10	1.37	2.14	2.13	2.67	ND
Assumed Coal Cost, \$/10 ⁶ Btu	0.425	ND	0.369	--	0.425	0.425	0.425	0.425	0.425	0.369	1.007	1.007	1.007	1.007	1.007	0.425	ND
Total Gas Cost, \$/10 ⁶ Btu	3.22	ND	2.79	2.74 ^(a)	2.71	3.83	3.50	3.70	3.38	3.10	4.66	3.69	3.51	3.64	3.94	3.40	3 to 6
Thermal Efficiency	71.7%	ND	71.1%	ND	78%	70%	64%	56.4%	67%	67.4%	60.3%	69.2%	60.6	70.1	66.1%	ND	ND

1. At 85.5% operating rate.
2. Included in operating costs.
3. Assumes 2.5¢/kWh credit for by-product power.

Notes: All feed and product rates 100% operating rate basis. Cost calculations assume 90% operating rate unless otherwise noted.

References: Col. 1 - Braun 1976; Col. 2 - Wyo. Coal Gas 1974; Col. 3 - Braun 1978b; Col. 4 - ANL 1977; Cols. 5-9 - Braun 1976; Cols. 10-15 - Braun 1978a; Col. 16 - Lummus 1977; Col. 17 - GRI 1979.

The capital cost listed in Table 4.4 is the total construction cost, including design and engineering costs, general facilities, contractor's fee and contingency. The total capital required includes capital cost plus working capital, startup costs, initial charge of catalysts and chemicals and interest during construction. Operating costs include labor, materials (except coal), utilities, and various overheads and miscellaneous items.

All feed and product rates are based on 100% operating rate. In the table, gas costs are calculated on a 90% capacity factor basis in all cases where this factor was reported, except the ANL study (column 4). The calculated gas costs shown are as reported in the original reference unless otherwise noted. Based on the fixed charge rate assumed in the individual studies, total gas cost varies between \$2.71 and \$4.66/10⁶ Btu, while overall thermal efficiency varies between 56.4 and 78%.

Based on published data shown in Table 4.4, standardized production costs were calculated and are presented in Table 4.5. All costs have been escalated to 1981 dollars using the Chemical Engineering plant cost index. A fixed charge rate of 1.53%/yr has been used (these include taxes and insurance). Total capital costs include plant capital cost, interest and escalation during construction, working capital, startup costs, and initial charge of catalysts and chemicals. Interest and escalation during construction was based on a three-year construction period, 12.5% interest, 8.5% escalation and a payout schedule of 25%, 50%, 25% for years 1, 2, 3, respectively. Due to the lack of accurate information on working capital, startup costs, and initial charge of catalysts and chemicals, these costs were collectively estimated at 6% of plant capital costs.

Examination of data shown in Tables 4.4 and 4.5 shows that the required capital investment is quite large. With coal at \$1/10⁶ Btu, capital charges typically account for 60 to 75% of total gas cost. Approximately 20% of production costs are due to the feed coal cost in most cases. Total estimated gas costs range from \$6.42 to over \$9.00/10⁶ Btu. Use of this gas for power production would be very expensive. The cost of fuel alone would contribute 64 to over 90 mills/kWh to total power production costs, assuming a heat rate of

TABLE 4.5. High Btu Gas Production - Unit Cost and Performance Summary^(a)

Column No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Gasification Process Coal Type	Lurgi Sub-Bitum.	Lurgi Sub-Bitum.	Lurgi Lignite	Lurgi Lignite	Hygas-02 Sub-Bitum.	Hygas-Fe Sub-Bitum.	Bigas Sub-Bitum.	Synthane Sub-Bitum.	CO ₂ Acceptor Lignite	CO ₂ Acceptor Bitum.	Lurgi Bitum.	Hygas- O ₂ Bitum.	Hygas- Fe Bitum.	Bigas Bitum.	Synthane Bitum.	Synthane Rosebud	ND ND
Coal Feed Btu/Btu Product	1.724	1.840	1.636	1.869	1.440	1.608	1.596	1.964	1.544	1.500	1.816	1.572	2.128	1.484	1.800	1.720	ND
Raw Water Feed (ton/10 ⁹ Btu prod.)	58	70 to 130	176	254	46	812.4	52	52	55	129	266	199	282	177	188	307	286
Oil, Tar, and Phenols (ton/10 ⁹ Btu gas)	6.0	3.7	4.3	4.9	2.5	1.4	0	2.88	0	0	1.104	1.66	1.364	0	2.40	~0	ND
<u>Capital and Operating Costs at 90% Operating Rate (1981 \$)</u>																	
Capital Cost \$/10 ⁶ Btu Prod/yr	19.05	ND	18.70	16.19	15.80	23.25	18.70	20.88	16.17	16.88	21.25	16.88	22.88	15.98	18.34	15.34	ND
Total Capital \$/10 ⁶ Btu Prod/yr. ^(b)	31.88	ND	31.70	27.10	26.44	38.92	31.30	34.94	27.06	28.25	35.57	28.25	38.29	26.75	30.69	25.67	ND
Operating Costs \$/10 ⁶ Btu Prod. ^(c)	1.72	ND	1.13	1.09	1.33	2.14	1.56	1.62	1.83	1.40	1.37	1.04	1.34	0.98	1.04	1.50	ND
By-Product Credit \$/10 ⁶ Btu Prod. ^(d)	0.536	ND	0.432	ND	0.352	0.303	0.061	0.273	0.108	0.073	0.250	0.306	1.843	0.132	0.429	0.144	ND
Capital Charge @ 15.3%/yr \$/10 ⁶ Btu	4.88	ND	4.79	4.15	4.05	5.95	4.79	5.35	4.14	4.32	5.44	4.32	5.86	4.09	4.70	3.93	ND
<u>Contribution of Coal Cost to Gas Cost</u>																	
Coal @ \$0.50/10 ⁶ \$/10 ⁶ Btu Prod.	0.862	0.92	0.818	0.935	0.720	0.804	0.798	0.982	0.772	0.750	0.908	0.786	1.064	0.742	0.900	0.860	ND
Coal @ \$1.00/10 ⁶ Btu \$/10 ⁶ Btu Prod.	1.724	1.84	1.636	1.869	1.440	1.608	1.596	1.964	1.544	1.500	1.816	1.572	2.128	1.484	1.800	1.720	ND
Coal @ \$1.50/10 ⁶ Btu \$/10 ⁶ Btu Prod.	2.586	2.76	2.454	2.804	2.160	2.412	2.394	2.946	2.316	2.250	2.724	2.358	3.192	2.226	2.700	2.580	ND
<u>Total Gas Cost with Selected Cost Factors: Capital Charges 15.3 and Coal at \$1/10⁶ Btu</u>																	
Total Gas Cost (mills/kWh)	7.78	ND	7.12	7.11	6.47	9.40	7.89	8.66	7.41	7.15	8.38	6.63	7.49	6.42	7.11	7.01	3 to 6 ^(e)

(a) All rates based on higher (gross) heating value. All costs except by-product credit escalated to 1981 dollars using Chemical Engineering plant cost index. All costs assume 90% operating rate.

(b) Total capital includes plant capital cost, interest and escalation during construction, working capital, startup costs, and initial charge of catalysts and chemicals.

(c) Operating costs include labor, materials except coal, utilities, ad valorem taxes and insurance, and miscellaneous charges and overheads.

(d) By-product credit has been treated as a saleable item and credited against operating costs in calculation of total gas cost.

(e) Gas cost is \$6 in first year of operation and decreases to approximately \$3 as capital is recovered.

ND No data or insufficient data.

References: Col. 1 - Detman 1976; Col. 2 - Wyo. Coal Gas 1974; Col. 3 - Detman 1978b; Col. 4 - Samsa et al. 1977; Cols. 5-10 - Detman 1976; Cols. 11-15 - Detman 1978a; Col. 16 - Weiss and Lumms 1977; Col. 17 - Linden et al. 1979.

10,000 Btu/kWh. Comparable costs for power generation in conventional coal-fired plants are significantly lower. A heat rate well below 10,000 Btu/kWh and an inexpensive method of producing power from the gas are required to make this option competitive.

Comparison of Table 4.5 with Table 4.3 shows that compared to LBG and IBG, SNG processes require more capital and coal per unit of output; operating costs are also higher. The Lurgi process is the only gasification process shown in both tables. Comparison of these (column 2 Table 4.3 with column 11, Table 4.5) shows an increase in capital, operating and coal cost per unit of output. Overall, the cost of SNG production is estimated to be about 40% more expensive than IBG production using the Lurgi process. This increased cost amounts to over \$2/10⁶ Btu. Because these two studies may not have been made using the same design or costing assumptions in all cases, the comparison should be considered indicative rather than quantitative. In any case, SNG production will be more expensive than IBG production because of the required additional process steps that increase capital and operating costs and decrease thermal efficiency.

4.1.3 Resource Requirements

The primary resource requirements of coal gasification are auxiliary energy, manpower, land, water, and major materials for construction and operation. Small quantities of other material resources necessary to operate the plant are not considered in this study.

Auxiliary Energy

The prevalent energy requirement for a coal gasification facility is coal. Other energy requirements may include steam or electricity, depending on the process. Steam is generated from coal but electricity may have to be purchased if the gasifier is not integrated with a power plant. The quantity of coal consumed in a gasification facility depends on the size of the facility, type of coal, type of gas produced and process technology employed, in addition to other site-specific conditions. Process efficiency determines the quantity of energy expended in gas production. Energy is required for coal preparation and pretreatment, boiler operation, cleanup and disposal, and other necessary auxiliary operations.

Manpower

A 243×10^9 Btu/day SNG plant has been estimated to require 750 employees for operation and maintenance. Construction of the plant is estimated to require 6580 man-years of effort (Samsa et al. 1977). Another estimate of manpower required for a 238×10^9 Btu/day SNG gasification facility is 10,781 man-years for construction and 589 workers per year for operation (U.S. EPA 1979).

Land

Land is required for both the gasification facility and disposal of solid wastes. In some cases, however, solid wastes may be returned to the mine for disposal. One study estimates that 400 acres are required for a Lurgi gasification facility (238×10^9 Btu/day SNG) and 25 to 30 acres/year for solid waste disposal (U.S. DOE 1980a). Another report estimates that a Lurgi SNG facility at Colstrip, Montana (also 238×10^9 Btu/day), would require a total of 800 acres of land (U.S. EPA 1979).

Water

Water requirements for a coal gasification plant are estimated to range between 1/2 and 4 tons per ton of coal feed or 45 to 300 tons per 10^9 Btu of product gas. The lower end of the range incorporates extensive water recycling and use of dry cooling where possible. Water is required primarily for three main purposes: cooling, process steam, and exhaust gas scrubbing, plus several minor purposes. Estimates for a 250×10^6 scf/day plant range from 1,400 to 3,600 acre-ft/yr for cooling, 3,900 to 5,800 acre-ft/yr for process steam and 1,500 to 6,000 acre-ft/yr for exhaust scrubbing of Western coal (Rogers 1980). Other estimates are projected as low as 2,300 acre-ft/yr and as high as 49,000 acre-ft/yr for the total coal gasification requirements.

Major Materials

The major materials for construction and operation of a coal gasification plant are structural steel, piping, and concrete. A 250×10^6 scf/day Lurgi gasification plant at Colstrip, Montana, would require 14,000 tons of structural steel, 58,000 tons of piping and 180,000 tons of concrete (U.S. EPA 1979).

Certain gasification processes have additional feedstock requirements, such as limestone (CO_2 acceptor process), potassium carbonate (Exxon process), and iron oxide (Hygas steam-iron process). Significant quantities of other raw materials may be required for auxiliary operations. Examples include make-up solvent for the acid gas removal system, chemicals used in water treatment, limestone for stack gas treatment, and replacement catalysts. Additional raw material requirements for a 243×10^9 Btu/day SNG plant are presented in Table 4.6.

4.2 USE OF COAL-DERIVED GASES TO PRODUCE ELECTRIC POWER

Fuel gases produced by coal gasification could provide a clean burning and convenient fuel for electric power generation. Gas-fired power plants do not require extensive solid fuel handling facilities, ash handling facilities, flue gas desulfurization equipment, and fly ash removal equipment required for coal-fired plants. In short, a gas-fired plant will be more compact, simpler, cleaner, and cheaper than a coal-fired plant. Use of coal-derived fuel gas for power production, however, has two serious and fairly obvious drawbacks: it

TABLE 4.6. Miscellaneous Raw Materials Requirements for a 243×10^9 Btu/Day SNG Plant (Samsa et al. 1977)

<u>Material</u>	<u>Use</u>	<u>Consumed/yr</u>
Methanol	Acid gas removal	---
Isopropyl ether	Phenol recovery	1,160 tons
Sulfuric acid	Water treatment	11,160 tons
Caustic soda	Water treatment	20,160 tons
Lime	Water treatment	3,000 tons
Limestone	Stack and tail gas treatment	40,220 tons
Desiccant	Oxygen plant	30 tons
Bauxite	Sulfur recovery	45 tons
Catalyst	Sulfur recovery	312 ft ³
Catalyst	Shift conversion	17,160 ft ³
Catalyst	Methanation	Regenerated

requires a relatively complicated and expensive plant to convert coal to gaseous fuel, and a significant fraction (~20 to 30%) of the feed coal heating value is lost in the conversion process.

Coal-derived fuel gas can be burned in a conventional boiler producing steam for power generation. However, because the gas is a clean fuel, it may be used in other systems that operate more efficiently than conventional steam plants. Several processes are currently under development that could potentially convert low or intermediate Btu gas to electricity at heat rates of 7,000 Btu/kWh or less, compared with approximately 10,000 Btu/kWh for conventional coal-fired plants. A committee of the National Research Council recently published an evaluation of the various advanced systems for utility power production (NRC 1977b). They concluded that gas turbine combined-cycles (GCC) are the most promising advanced system, considering efficiency, cost, and state of development. Gas turbine combined-cycles consist of an open-cycle gas turbine combined with a steam turbine that operates off steam produced using waste heat from the gas turbine. The technology and performance of GCC systems are discussed in the following section. Although several other advanced systems are under development (e.g., fuel cells, MHD generators, metal vapor topping cycles, etc.), only the GCC system will be discussed in this study.

4.2.1 Gas Turbine Combined-Cycle Systems for Power Generation

Gas turbine combined-cycle power generation systems (GCC) provide an attractive means of producing power from clean liquid and gaseous fuels. A few of these systems are currently in use in base and intermediate load utility applications. Present systems use natural gas or oil, and a major impediment to wider use of GCC systems is the lack of an adequate suitable fuel supply (Bennett, Riedel and Krack 1978). Units currently in operation produce electricity at heat rates on the order of 9,000 Btu/kWh or less (Allison and Berman 1976; Todd and Sanesi 1975). However, advanced systems currently under development will reduce heat rates significantly, potentially to 7,000 Btu/kWh or less. If these high efficiencies are achieved, production of baseload electric power from coal-derived fuel gas may become economically competitive with power produced by direct combustion of coal in a conventional steam boiler.

Several gas turbine combined-cycle configurations could be used to produce power from coal-derived fuel gas. The primary configuration of interest here consists of an open-cycle combustion gas turbine and a conventional steam turbine. The hot exhaust gases from the gas turbine pass through a heat recovery steam generator that supplies steam for the steam turbine.

The main components of the gas turbine are the combustor, expander and compressor. Fuel gas is fed to the combustor at elevated pressure (typically 8 to 16 atm) where it is mixed with compressed air from the compressor and combusted. The hot combustion gases expand through nozzles that reduce the pressure and increase the velocity of the gases. The gases then flow through the expander where they impinge on several stages of rotating and stationary blades, which reduces the pressure to approximately atmospheric. The gases then flow to the heat recovery steam generator. The force of the gases on the blades causes the turbine rotor to spin, driving both the compressor and an electric generator; the gases do work on the rotor, which reduces their temperature. The temperature of the exhaust gases depends mainly on the inlet temperature, inlet pressure, and type of cooling. A typical example is an advanced air-cooled turbine with inlet temperature and pressure of 2,400°F and 12 atm; for one such design the outlet temperature is calculated to be 1184°F (NRC 1977b).

The temperature of the gases flowing from the combustor to the first stage of the expander is controlled by addition of excess air. The primary emphasis in development of advanced turbines is to increase the allowable inlet temperature, which improves the overall cycle efficiency. The type and amount of cooling required also affect efficiency. Ceramic blades, which do not require cooling, could provide substantial improvements in efficiency. Estimates of advanced combined-cycle system efficiencies vary considerably depending on inlet temperature and cooling requirements. For example, Robson et al. (1975) predicts station efficiencies varying between 44% for a 2,200°F expander inlet temperature with "conventional cooling" and 48% for a 2,600°F inlet temperature with ceramic vanes and blades. Another study (Strong 1976) predicts combined-cycle efficiencies for a 2,600°F inlet temperature varying between 53.3% for a cooling air flow of 5% of total compressor flow and 49.9% for cooling air flow of 20%. Because currently available turbines for power plant applications are

limited to inlet temperatures less than 2,000°F, some of the systems under consideration probably will require a very substantial advance in the state-of-the-art. However, reduction of heat rates to the range of 7,500 to 8,000 Btu/kWh will require only a modest advance.

The heat recovery steam generator/steam turbine system is similar to conventional steam systems and will not be described here. In advanced combined-cycle systems the steam turbine will typically produce less than half of the total power. The overall cooling water requirements for combined-cycle systems is much lower than for systems using only steam turbines. This difference occurs because the gas turbine will require little or no cooling water and the steam turbine will require less than half that of conventional systems.

4.2.2 Power Production with Integrated Coal Gasification Combined-Cycle Systems

By integrating a GCC system with a coal gasification plant, cost savings can be made and overall thermal efficiency can be improved compared to separate gasification and power plants. Several studies have been published on these systems; the general conclusions reached in these studies are that integrated gasification combined-cycle systems (IGCC) can potentially produce electric power at lower cost and higher thermal efficiency than conventional coal-fired systems with stack gas scrubbers (Chandra et al. 1978b; Jones and Donahue 1977; Robson, Belcher and Colton 1976). The IGCC systems are also expected to have lower air emissions and water requirements.

The greatest cost savings in integrating the gasification plant with the power plant comes from use of the power plant's heat recovery steam generator to supply the steam requirements of the gasification plant. A separate gasification plant would require boilers fired with coal or product gas for steam production. Use of the heat recovery steam generator to produce steam for the gasification plant essentially amounts to "cogeneration" and can improve overall thermal efficiency and reduce costs. In some cases the air compressor for the gas turbine may also supply compressed air for gasification. Other areas of the plant that may be integrated beneficially include process waste heat utilization, cooling water system, and general facilities.

Precise definition of coal gasification economics is difficult. Commercial coal gasification plants are limited to a few foreign operations that typically serve a different purpose than is under consideration here (e.g., production of a synthesis gas for fertilizer or chemical production). A few units are in operation in this country, but they are all very small and bear little resemblance to the large integrated operations that are required to economically produce utility fuel gas.

In addition to the general lack of commercial experience with coal gasification, the large number of systems available or proposed, different types of feed coal, and various other site-specific factors can significantly affect the economics. Rather than provide a single generalized cost figure, several published capital and operating cost estimates were compiled for comparison. Most of these estimates have been made using factored cost estimating techniques. The level of detail in these studies is somewhere between the "preliminary estimate" and a "study estimate" as defined by Peters and Timmerhaus (1968, pp. 95-99). The accuracy of this type of estimate is typically no better than ± 20 to 30%. In the case of developmental processes where little data are available, the estimates may not even be that good.

Among the various design studies that have been published, those published by Fluor Engineers and Constructors under EPRI sponsorship appear to be the most up-to-date (Chandra 1978a, 1978b; Coleman et al. 1979). The results of the Fluor-EPRI studies are also well suited for use in this study because important assumptions are clearly spelled out and process designs and cost breakdowns are given in sufficient detail to allow comparison among this study and others.

In the Fluor-EPRI studies, several IGCC process designs were evaluated. For each design, major equipment was sized and costed and an estimate of plant performance was made. Overall plant capital and operating costs were then estimated and the total cost of power was calculated using specified assumptions. Plant designs studied include adiabatic combustor combined cycles integrated with several different gasification processes and a conventional coal-fired power plant with stack gas scrubber for comparison. Summaries of the results of the Fluor-EPRI studies are reported as columns 1 through 7 of Table 4.7. The plant design using Lurgi gasification was based on use of

TABLE 4.7. Integrated Gasification Combined-Cycle Power Generation - Published Plant Performance and Cost Estimates(a)

Column No. Gasifier Type	1 Fixed Bed	2 Fixed Bed Slagging B.G.C.	3 Entrained (Air) Foster-Wheeler Bituminous	4 Entrained (O ₂) Foster-Wheeler Bituminous	5 Entrained Comb. Egg. Bituminous	6 Entrained Texaco Bituminous	7 (b) (b) Bituminous
Gasifier Make Coal Type	Lurgi Sub-Bituminous	Lurgi Bituminous	Foster-Wheeler Bituminous	Foster-Wheeler Bituminous	Comb. Egg. Bituminous	Texaco Bituminous	Bituminous
Coal Feed Rate (Ton/Day)	13,900	10,000	10,000	10,000	10,000	10,000	
Coal Feed Rate (10 ⁹ Btu/Day)	231	244.7	244.7	244.7	244.7	244.7	
Gas Turbine Inlet Temp. (°F)	2,400	2,400	2,400	2,400	2,400	2,400	--
Gas Turbine Power (MW)	590	857	751	803	886	745	--
Steam Turbine Power (MW)	430	385	504	384	307	448	--
Net System Power (MW)	988	1,212	1,213	1,149	1,138	1,157	1,000
Make Up Water Feed (gpm/1000 MW)	7,905	6,716	6,622	7,034	7,596	7,950	14,145
Net Heat Rate (8tu/kWh)	9,762	8,410	8,428	8,876	8,959	8,813	9,928
Overall Efficiency (% of Coal HHV)	35.0	40.6	40.5	38.5	38.1	38.7	34.4
<u>Estimated Capital Costs (Mid-1976 \$)</u> <u>Per Unit of Installed Capacity</u>							
Capital Cost(c) \$/kW	721.1	566.3	561.0	588.0	744.3	652.1	629.0
Preproduction and Startup Costs \$/kW	49.0	38.6	38.7	40.1	49.9	43.7	41.7
Working Capital \$/kW	45.7	37.1	36.9	38.7	45.6	41.2	46.2
Interest During Construction @ 8%, \$/kW	89.9	69.1	658.5	71.8	90.9	79.6	121.5
Total Capital Required \$/kW	905.7	711.1	705.1	738.6	930.7	816.6	838.4
<u>Estimated Operating Costs @ 70</u> <u>Operating Rate (Mid-1976 \$)</u>							
Operating Costs(d) \$10 ⁶ /yr	36.92	33.04	32.39	31.76	40.11	33.78	43.29
Coal Cost @ \$1/10 ⁶ Btu, \$10 ⁶ /yr	59.14	62.52	62.52	62.52	62.52	62.52	60.88
Local Taxes and Insurance \$10 ⁶ /yr	17.38	16.75	16.60	16.51	20.71	18.44	15.73
Byproduct Credit \$10 ⁶ /yr	3.27	3.16	3.27	3.27	--	--	--
Capital Charges @ 15.6%/yr, \$10 ⁶ /yr	139.59	134.45	133.42	132.34	165.23	147.39	130.79
Power Cost(e)	41.2	32.8	32.5	34.1	41.4	37.0	40.9

(a) Chandra et al. 1978b.

(b) Conventional coal-fired steam electric plant with stack gas scrubbers.

(c) Includes 5% sales tax and 15% project contingency.

(d) Operating costs except coal, local taxes and insurance.

(e) Assumes 15.6% yr capital charge rate, \$1/10⁶ Btu coal, and 70% operating rate.

Western subbituminous coal; all others used bituminous coal (Illinois #6). Plants were designed for coal feed rates of 230 to 245×10^9 Btu/day with a net power output of 988 to 1212 MW, depending on the thermal efficiency of the particular design. The capital costs shown include the direct and indirect cost of all portions of the plant from coal receiving to power production, including required general facilities but not including coal transportation or power transmission equipment.

For comparison, cost and performance estimates for a coal-fired steam-electric plant with stack gas scrubbers are shown in column 7 of Table 4.7. Comparison of the results shown in column 7 with those for the IGCC systems shown in Table 4.7 indicates that IGCC systems potentially have several significant advantages compared to conventional coal-fired systems. Thermal efficiency is better for IGCC systems in every case; for two IGCC systems it is more than 20% higher than the conventional plant. Capital costs are lower for three IGCC systems and total estimated power costs are lower than those of the conventional steam-electric plant for four of the six IGCC systems shown. The water requirement is much lower for the IGCC systems, typically by about 50%.

Use of the gasification/gas cleanup/GCC systems discussed in the Fluor-EPRI studies will require a modest advance in the state-of-the-art. The designs used in these studies have not been thoroughly optimized; some improvement in the overall economics might be expected as operating experience is gained and the processes are optimized. In general, systems were selected that are expected to be available in the mid to late 1980s. Further improvements in the turbine and gas cleanup systems are possible that would lower the cost and improve efficiency of IGCC systems.

To obtain costs on a more comparable basis with those given in other sections of this report, we have adjusted the data in Table 4.7. These adjusted costs are shown in Table 4.8. Costs have been adjusted to 1981 dollars using the Chemical Engineering Plant Index. The capital charge rate has been increased to 15.3%. The predicted costs at 15.3%/yr capital charge rate with coal at $\$1/10^6$ Btu range from 43.7 to 56.1 mills/kWh for IGCC systems compared with 55 mills/kWh for the conventional steam system. The indicated cost savings for the IGCC systems range from zero to 20%. Because of the uncertainty associated with these values (± 20 to 30%), the only conclusion that can be

TABLE 4.8. Integrated Coal Gasification Combined-Cycle Power Generation - Standardized Plant Performance and Cost Estimates

Column No. Gasifier Type	1	2	3	4	5	6	7
Gasifier Make Coal Type	Fixed Bed Lurgi Sub-Bituminous	Fixed Bed Slagging B.G.C. Bituminous	Entrained (Air) Foster-Wheeler Bituminous	Entrained (O ₂) Foster-Wheeler Bituminous	Entrained Comb. Eng. Bituminous	Entrained Texaco Bituminous	Conventional Combustion Bituminous
Net System Power (MW)	988	1,212	1,213	1,149	1,138	1,157	1,000
Make Up Water Feed (gal/kWh)	0.47	0.40	0.40	0.42	0.53	0.46	0.85
Net Heat Rate (Btu/kWh)	9,762	8,410	8,428	8,876	8,959	8,813	9,928
<u>Estimated Capital Costs Per Unit of Installed Capacity (1981 \$)</u>							
Capital Cost (\$/kW)	1,063.6	835.3	827.5	867.3	1,097.8	961.9	927.8
Preproduction and Startup Cost (\$/kW)	72.3	56.9	57.1	59.2	73.6	64.5	61.5
Working Capital (\$/kW)	67.4	54.7	54.4	57.1	67.3	60.8	68.2
Interest During Const. @ 8% (\$/kW)	132.6	101.9	101.0	105.9	134.1	117.4	179.2
Total Capital Required (\$/kW)	1,335.9	1,048.8	1,040.0	1,089.5	1,372.8	1,204.6	1,236.7
<u>Estimated Operating Costs Per Kilowatt hour of Output at 70% Operating Rate (1981 \$)</u>							
Operating Costs ^(a) (mills/kWh)	8.99	6.56	6.42	6.65	8.48	7.02	10.41
Coal Cost @ \$0.50/10 ⁶ Btu, (mills/kWh)	4.88	4.21	4.21	4.44	4.48	4.41	4.96
Coal Cost @ \$1.00/10 ⁶ Btu, (mills/kWh)	9.76	8.41	8.43	8.88	8.96	8.81	9.93
coal Cost @ \$1.50/10 ⁶ Btu, (mills/kWh)	14.64	12.62	12.64	13.31	13.44	13.22	14.89
Byproduct Credit, (mills/kWh)	0.54	0.42	0.44	0.47	--	--	--
Local Taxes and Insurance (mills/kWh)	4.23	3.32	3.29	3.46	4.38	3.83	3.78
Capital Charges @ 15.3%/yr (mills/kWh)	33.3	26.2	26.0	27.2	34.3	30.1	30.9
<u>Total Power Cost with Coal @ \$1/10⁶ Btu and Capital Charges @ 15.3%</u>							
Total Power Cost mills/kWh	55.7	44.1	43.7	45.7	56.1	49.8	55.0

(a) Operating costs do not include coal or local taxes and insurance.

reached is that IGCC facilities are within the same range as conventional coal plants and are likely to be competitive with them on an economic basis. When the advantages of lower air emissions and water requirements are considered, IGCC facilities may be preferred.

4.2.3 Combined-Cycle Plants Not Co-Sited with a Gasification Plant

In this section, the economics of combined-cycle power plants that could produce electric power from gas produced in a separate gasification plant are discussed. The potential advantages of IGCC systems have led to a considerable amount of interest in these systems in recent years. Because of this interest, a large amount of published information is available on the expected cost and performance characteristics of IGCC systems. However, there appears to be little published information on the cost and performance characteristics of advanced combined-cycle systems that are fueled with coal-derived gas but that are not integrated with the gasification plant. Published information on combined-cycle power plants is generally based on use of liquid fuel. Therefore, a very rough estimate of the cost of these systems was made using published cost data on integrated systems and liquid-fueled systems.

The Fluor reports cited previously give separate cost estimates for gasification plants producing either intermediate Btu gas or electric power using the BGC slagging gasifier (Chandra et al. 1978a, 1978b). Adding the combined-cycle power production equipment increased the plant capital cost by an amount equivalent to \$259/kW (mid-1976 dollars not including contingency). The combined-cycle was integrated with the gasification plant, which reduced cost and improved the plant efficiency compared to having the gas plant completely separate from the power plant. Using the results given in the Fluor reports, the cost of the combined-cycle plant has been estimated to be roughly 6% higher or about \$274/kW (mid-1976 dollars) if it were operated separately from the gasification plant. Escalation to 1981 dollars gives \$404/kW. This is in good agreement with published costs data for oil-fired combined-cycle power plants (Bechtel 1977; EPRI 1979; NRC 1977b). The contingency used by Fluor for the advanced (2400°F firing temperature) GCC system is about 20% of capital cost. A contingency of 15% was assumed by Bechtel (1977) for presently available (2000°F firing temperature) oil-fired GCC power plants. If the more conservative contingency (20%) is used, the capital cost, including contingency, is

\$485/kW (1981 dollars). Estimated construction times range from 24 to 36 months (Bechtel 1977; EPRI 1979; Chandra et al. 1978b). The total capital required includes capital cost (\$485/kW); land, inventory and startup costs (~\$24/kW); escalation during construction (EDC); and interest during construction (IDC). Using a current dollar analysis (EDC = 8.5%/yr, IDC = 12.5%/yr), the total capital is \$682/kW, assuming a 36-month construction period.

A heat rate of 7188 Btu/kWh was estimated from the Fluor report based on pressurized gas fuel and a turbine firing temperature (Chandra et al. 1978b). This is comparable with estimates for liquid-fueled combined cycles of 8345 Btu/kWh for 2000°F firing temperature, 7300 Btu/kWh for 2200°F firing temperature and 6679 Btu/kWh for 3000°F firing temperature (EPRI 1979; NRC 1977b). EPRI (1979) expects the 2200°F unit to be available for commercial orders by about 1986. For purposes of economic analysis, the 7300 Btu/kWh was selected as a reasonable heat rate for combined-cycle systems that are likely to be available for commercial operation by 1990.

The increase in operating costs from adding an advanced GCC system to a gasification plant is estimated at 3.66 mills/kWh in 1976 dollars or 5.40 mills/kWh in 1981 dollars (Chandra et al. 1978a, 1978b). A modest increase in operating labor would be expected if the GCC system were operated as a separate plant. Examination of the operating cost breakdown in the original design studies shows that greater than 80% of total operating costs (exclusive of coal) were estimated by simply multiplying component capital costs by various experience factors. On this basis, the increase in operating costs for the separate plants should be roughly the same as the increase in capital costs. Therefore, the total operating cost for a separate GCC system is estimated to be about 6 mills/kWh. Since no advanced GCC plants have been operated, this number is considered to be somewhat speculative. Another report estimates an operating cost of 2 mills/kWh for oil-fired combined cycles (EPRI 1982). Utility experience with present generation gas turbines and GCC systems has been quite variable; in some cases maintenance costs alone have exceeded 5 mills/kWh (compare Bennett, Riedel and Krack, 1978). However, maintenance costs are expected to be reduced as "bugs" are worked out of the systems and as the technology matures.

The cost of power from a GCC system includes capital costs, operating costs, and delivered fuel costs. With a fixed charge rate of 15.3%/yr and a 70% capacity factor, the unit capital charges are calculated as 17.0 mills/kWh. If 6 mills/kWh is used for the operating costs, total capital plus operating cost would be 23.0 mills/kWh. Table 4.9 gives total power production costs for various delivered fuel costs and heat rates.

The estimated cost of SNG using Lurgi gasification is about $\$7/10^6$ Btu (Table 4.5) plus delivery cost. The costs shown in Table 4.9 show that even with very efficient advanced combined-cycle systems, baseload power most likely cannot be produced from this gas at a price competitive with conventional coal combustion systems.

The costs of LBG and IBG (Table 4.3) is significantly lower than SNG. The projected cost of power production with an IBG- or LBG-fired advanced combined-cycle system falls within the competitive range with other options. However, these systems most likely will not be preferred for cases under consideration in the present study (i.e., for baseload power demand centered approximately 1000 miles from the coal supply). If the gasification plant is located near the load center, it would be more economical to integrate the combined-cycle system with the gasification plant. The other option of locating the gasification plant at the coal source and transporting the gas to the power plant located at the load center is not economical because of the high cost of transporting IBG and LBG.

TABLE 4.9. Estimated Power Production Costs for GCC Systems

Heat Rate (Btu/kWh)	Power Cost, mills/kWh ^(a)			
	Delivered Gas Cost ($\$/10^6$ Btu)			
	\$4	\$5	\$6	\$7
7,000	51.0	58.0	65.0	72.0
7,500	53.0	60.5	68.0	75.0
8,000	55.0	63.0	71.0	78.0
9,000	59.0	68.0	77.0	84.0

(a) Capital and operating costs are assumed to total 23.0 mills/kWh in all cases.

4.3 PIPELINE TRANSPORTATION OF GASES PRODUCED BY COAL GASIFICATION

If coal is to be converted into a clean fuel gas prior to use, gas pipelines offer an attractive method of transporting energy from the vicinity of the coal deposits to major energy demand centers. Over the years the United States has developed a vast network of gas pipelines for transporting natural gas. These pipelines have proven to be a convenient and economical way to move large quantities of energy over long distances. Transporting SNG from coal by pipeline is particularly attractive because this product is directly interchangeable with natural gas; SNG can be transported in existing pipelines either alone or mixed with natural gas.

4.3.1 Pipeline Transport Process

Gas transmission pipelines are typically of steel construction and range in size up to about 4 ft in diameter. They are operated at high pressure (~1000 psi or in some cases higher) to increase capacity. Compressor stations are located at intervals along the line to make up pressure loss caused by friction. The compressor stations usually burn gas from the pipeline in reciprocating or gas turbine engines to provide power required for compression. Spacing of compressor stations can vary widely depending on several factors, including pipeline capacity, station pumping power, and terrain. Based on pipeline lengths and number of compressors, spacing ranges from 30 to 350 miles (Oil and Gas Journal Aug 1980) and averages ~170 miles.

Table 4.10 shows the range of pipeline capacities for various pipeline diameters. The lower capacity within the range corresponds to less energy

TABLE 4.10. Pipeline Capacity Ranges^(a)

<u>Pipeline Diameter (in.)</u>	<u>Capacity (scf/day)</u>
20	80 to 200 x 10 ⁶
24	150 to 400 x 10 ⁶
30	250 to 500 x 10 ⁶
36	400 to 800 x 10 ⁶

(a) Banks 1977b.

expended in transmission (i.e., less compressor work). As the fuel value increases, there is incentive to reduce flow rate and reduce transmission energy cost.

4.3.2 Pipeline Transport Economics

Because of the high capacity and simple operation of gas pipelines, they have proven to be an economical method of transporting large quantities of gas. Typical costs of various energy transportation alternatives were compared in a recent Gas Research Institute (GRI) publication (Linden et al. 1979). Their results are shown in Table 4.11; however, the basis for these costs was not given in the publication.

In a study published by Argonne National Laboratory (ANL), capital and operating costs were estimated for a gas pipeline designed to deliver the output of a 250×10^6 scf/day SNG plant from North Dakota to Illinois (Samsa et al. 1977). A 26 in. diameter pipe was assumed and the total length was 900 miles. Pertinent economic results from that study are summarized in Table 4.12.

Capital Costs

The Oil and Gas Journal (August 1980) provides capital cost estimates for several pipelines. From that data, the cost components for a generic 30 in. pipeline were estimated in 1981 dollars using the Oil and Gas Journal - Morgan Oil Pipeline Cost Index (Morgan 1982) and are given in Table 4.13.

The range of total capital costs varied from \$435,000 to \$956,000/mile. The nature of the terrain through which the pipeline must be built will affect

TABLE 4.11. Cost of Energy Transportation^(a)

<u>Energy Form</u>	<u>Typical Cost (¢/10⁶ Btu/100 mi)</u>
Oil	1
Gas	3
Coal	4 to 6

(a) Linden et al. 1979.

TABLE 4.12. ANL Reference Pipeline Summary Economic and Performance Estimates^(a)

Pipeline capacity	250 x 10 ⁶ scf/day
Transmission distance	900 mi
Number of compressor stations	4
Installed compressor hp	24,000
Compressor fuel use	3.59 x 10 ⁶ scf/day
Leakage and misc. losses	2.21 x 10 ⁶ scf/day
Estimated Capital Cost (1975\$)	
Pipe line	\$198.0 x 10 ⁶
Compressor stations	\$13.8 x 10 ⁶
Total capital cost	\$211.8 x 10 ⁶
Estimated operating costs	\$6.75 x 10 ⁶ /yr
Total transmission cost (1975\$) (except fuel use and losses)	\$0.37/1,000 scf
Total fuel use and losses	0.024 scf/scf delivered

(a) Samsa et al. 1977.

TABLE 4.13. Generic 30 in. Diameter Pipeline Capital Cost Estimates^(a)

<u>Component</u>	<u>\$/mi^(b)</u>
Right of Way	7,800
Materials	333,500
Labor	145,200
Miscellaneous	69,800
Total	556,300

(a) Oil and Gas Journal August 1980.

(b) Escalated to 1981 dollars using the
Oil and Gas Journal - Morgan Oil
Pipeline Cost Index (Morgan 1982).

the cost. Table 4.14 shows approximate cost multipliers (to be applied to the generic values above) for four terrain types.

The construction of compressor stations adds significant capital cost to the pipeline transmission system. A review of 34 systems (Oil and Gas Journal Aug 1980; Morgan 1982) shows a range of \$519 to \$3139/hp with an average of \$1284/hp. If the cost of land is removed, the cost of the physical plant is approximately \$1273/hp. As previously discussed, the size of any given compressor station can vary greatly depending on station spacing, pipeline capacity and terrain. For a 300×10^6 scf/day pipeline with 100 mile station spacing, a compressor rating of ~4500 hp per station can be estimated. This gives a capital cost of $\$5.80 \times 10^6$ for this generic station. This cost is in reasonable agreement with the ANL estimate from Table 4.12 for four stations (with inflation to 1981 dollars considered).

The land cost of ~\$10/hr also agrees reasonably well with an estimate of 40 acres per station (U.S. DOE 1980b), and a land cost of ~\$1200/acre.

Operation and Maintenance Costs

The operation and maintenance cost for the pipeline system includes gas consumed in the compressor station, gas lost through leakage, and operation and maintenance staff and materials.

TABLE 4.14. Approximate Terrain Capital Cost Multipliers^(a,b)

Flat	0.8
Rolling	1.0
Rolling/Mountainous	1.35
Mountainous	1.7

(a) Oil and Gas Journal August 1980.

(b) Based on high/low estimates from Oil and Gas Journal for a 30 in. diameter line.

Gas consumption will, of course, be a function of the length of the line. However, an estimate can be made based on a generic compressor spacing of 200 mi and 4500 hp per station for a 300×10^6 scf/day capacity line. Efficiencies for reciprocating compressors are given in the literature as 22% (U.S. DOE 1980b) and those for gas turbine compressors as 28% (Stillwagon 1975). Assuming SNG at 1000 Btu/scf gives 1.2×10^6 scf/day for reciprocating compressors and 0.96×10^6 scf/day gas turbines. With five stations on a 1000 mi line this would be 6.0×10^6 scf/day and 4.8×10^6 scf/day or 2.8% and 1.6% of the capacity for the two respective compressor types.

Gas losses from the system include losses at compressors, pipeline leakage and venting during compressor blowdown. This last category has been greatly reduced recently. Total losses as high as 2.4% of capacity have been reported (Banks 1977a). A more realistic value for current practice is about 1% (Samsa et al. 1977).

The operation and maintenance costs for a pipeline can be approximated by staff required. Table 4.15 shows the staff required for three sections of the Trailblazer pipeline. Assuming \$30,000 annual cost per employee implies an annual cost of \$2200/mi for operation and maintenance of the line (excluding gas costs).

Operation staff for the compressor station can be estimated based on the new station built for the Trailblazer line. The Lincoln station is a 4500 hp unit and employs 12 people (FERC 1980). Again assuming \$30,000 per employee

TABLE 4.15. Trailblazer Pipeline Staff Requirement^(a)

<u>Section</u>	<u>Miles</u>	<u>Staff</u>	<u>Staff/mi</u>
Overthrust	88	4	0.091
CIG	264	17	0.064
Trailblazer	445	37	<u>0.083</u>
Average			0.073

(a) FERC 1980.

yields a compressor station operating cost of \$360,000/yr per compressor station. The maintenance cost for a station can be roughly approximated by comparison to generic design guidelines. For chemical process facilities, an annual maintenance cost of 2 to 6% of fixed capital investment has been proposed (Peters and Timmerhaus 1968). The range suggested is a function of the sophistication and complexity of the process equipment. A compressor station is on the low end of such a scale. It can be further assumed that the operation staff, already accounted for, will perform some portion of the maintenance. An estimate of 1% of fixed capital costs can therefore be taken as the annual maintenance cost for a compressor station. For a 4500 hp station with a fixed capital cost of \$1284/hp, this corresponds to \$58,000/yr.

Using a capital charge factor of 15.3%/yr and assuming that gas delivery averages 90% of capacity, a total gas transmission cost of about \$1.25/10⁶ Btu is calculated for a 1000 mile pipeline. In addition, about 2.6% of the gas would be consumed as fuel and leakage losses. With a feed gas cost of \$7/10⁶ Btu, the approximate delivered gas cost including consumption would be \$8.43/10⁶ Btu.

4.3.3 Pipeline Transmission of Low or Intermediate Btu Gas

Pipeline transmission of low or intermediate Btu gases over long distances does not appear to be economical (NRC 1977a). The increased gas volume per unit of energy transmitted alone will increase transmission costs by a factor of three or more; fuel required for compressor operation will also increase by a factor of three or more. Technical and safety problems will most likely result in additional cost increases. Because of these factors, production of LBG or IBG followed by long distance pipeline transmission does not appear to be an economically viable option. Shipment of coal to a point near the energy demand center followed by long distance pipeline transmission does not appear to be an economically viable option. Shipment of coal to a point near the energy demand center followed by LBG or IBG production is more economical; however, pipelines could be economically employed for local distribution up to ~100 miles (NRC 1977a).

4.3.4 Pipeline Transport: Resource Consumption and Environmental Effects

The resource consumption and environmental effects of pipeline transfer are discussed briefly below.

Resource Consumption

The major resource consumed in gas pipelines is steel. The steel required is a function of diameter and thickness. Table 4.16 gives lengths, diameter and pipe wall thickness for three existing pipelines.

Environmental Effects

The major environmental impact of gas pipelines occurs during construction. Construction impacts of pipelines are discussed in Section 3.3 of this report on slurry pipelines.

During operation, the major environmental impact is emissions from the combustion of gas in compressor stations. Emission estimates from the ANL study (1977) are given in Table 4.17 (see Table 4.12 for pipeline specifications).

Another estimate of compressor emissions is given in Table 4.18. Columns 2 and 4 were added to the source information to allow comparison to

TABLE 4.16. Existing Pipeline Steel Usage

<u>Pipeline</u>	<u>Section Length (miles)</u>	<u>Outer Diameter (inches)</u>	<u>Wall Thickness (inches)</u>	<u>Steel (tons/mile)</u>
Texas-Thousand ^(a)	585	30	0.422	352
	25	30	0.500	416
	25	30	0.625	517
Trailblazer ^(b)	88	36	0.375	376
	264	36	0.358	360
	445	36	0.358	360

(a) Oil and Gas Journal August 1980.

(b) FERC 1980.

TABLE 4.17. ANL Reference Pipeline Summary Environmental and Resource Factors^(a)

<u>Emissions (gas leakage not included)</u>	<u>Ton/day</u>	<u>lb/10⁹ Btu per 100 mi</u>
NO _x	0.61	0.54
SO _x	0.012	0.011
CO	0.15	0.13
Hydrocarbons	0.027	0.024
Particulate	0.0246	0.022

(a) Samsa et al. 1977

TABLE 4.18. Natural Gas-Fired Compressor Emissions^(a)

<u>Emissions</u>	<u>Reciprocating</u>		<u>Gas Turbine</u>	
	<u>lb/10³ hp-hr</u>	<u>Tons/day</u>	<u>lb/10³ hp-hr</u>	<u>Tons/day</u>
NO _x	24	6.9	2.9	0.8
SO ₂	0.004	0.001	0.004	0.001
CO ^(b)	3.1	0.9	1.1	0.3
HC ^(c)	9.7	2.8	0.2	0.06

(a) U.S. EPA 1977.

(b) Assuming 2000 grams/10⁶ scf.

(c) As C; non-methane HC = 5.10%.

the ANL values. The ANL generic pipeline assumed 24,000 hp of compressor capacity. The source units, of lb/hp-hr, were converted to ton/day using this compressor capacity. Comparison of Tables 4.17 and 4.18 shows general agreement between ANL values and those for the gas turbine, except for SO₂ emissions. The quantity of SO₂ will depend on the level of trace sulfur compounds in the gas and will be relatively small.

4.4 ENVIRONMENTAL EFFECTS OF COAL GASIFICATION-BASED ELECTRIC POWER PRODUCTION OPTIONS

Total environmental residuals include contributions from the gasification plant, power plant, coal mine and gas transmission or coal shipping operation.

This section only discusses emissions and effluents related to the power plant and gasification plant.

In general, emissions of atmospheric pollutants from power plants using coal gasification can be economically controlled with available technology to levels as low as or lower than those from a comparable conventional coal-fired plant. Potential water effluents are highly process specific. For some gasification processes, controlling pollutants in waste water streams will be difficult and expensive. Other processes will have little or no waste water other than cooling tower blowdown. Solid waste will consist primarily of ash. Disposal of ash should pose no more, and in some cases less, environmental hazard than disposal of ash from combustion of coal. In most cases, no scrubber sludge will have to be disposed of because sulfur will be converted to elemental sulfur, which may be sold as a by-product. A more detailed discussion of the various categories of potential emissions follows.

4.4.1 Air Pollutant Emissions

The major sources of gaseous pollutants in a coal gasification plant are tail gas from the acid gas ($\text{H}_2\text{S} + \text{CO}_2$) removal step, sulfur compounds in the product gas, and flue gas from process steam and auxiliary power production. Other operations within the plant may produce small quantities of purge gases or vent gases (e.g., lockhopper purge gas and dissolved gases released from liquid streams). In the power plant, sulfur compounds in the fuel gas will be converted primarily to SO_2 . NO_x may be produced by the combination of elemental nitrogen and oxygen at the high temperatures present in the combustor flame, or it may be produced by oxidation of nitrogen compounds (e.g., NH_3) present in the fuel gas. Residual ash-forming materials from the coal may be carried through with the fuel gas and will appear in the combustion flue gas as fine particulate. Incomplete combustion of the fuel gas may result in excessive amounts of CO in the stack gas.

In general, emissions of primary "criteria" air pollutants (SO_x , NO_x , CO, and particulates) from a power plant based on coal gasification can be controlled to levels less than those of an equivalent conventional coal-fired power plant with stack gas scrubbers. In some cases the emissions may be reduced by one to two orders of magnitude when compared to a conventional power

plant. The lower gaseous emission levels attainable in a gasification-based power plant result from several factors. The amount of gas to be cleaned is substantially less than the flue gas from coal combustion, and gasification processes typically operated at elevated pressure, further reducing the volume of gas processed. Elevated pressure also increases the driving force for gas absorption. Nitrogen and sulfur compounds in the fuel gas are in a chemical form that is relatively easy to remove, as compared to SO_2 present in flue gas from coal combustion. Emissions standards have not been set for coal gasification plants; however, guidelines are presently being prepared and are expected to be issued within the next year (Synfuels 1980).

In the coal gasification process, the majority of sulfur from the coal becomes H_2S with fuel gas with a smaller amount of COS and traces of other sulfur compounds. In coal gasification-based power plants, sulfur emissions are controlled by removing sulfur from the fuel gas prior to combustion. Commercially proven processes are available for reduce the sulfur concentration in the fuel gas to less than 1 ppm. This is more than two orders of magnitude lower than current emission limits. However, because of the adverse effect on power production cost, the sulfur will probably only be reduced to the level required by environmental regulations. Fluor makes the estimate that reducing the sulfur emission limit from 1.2 to 0.10 lb $\text{SO}_2/10^6$ Btu will increase power costs by 7.6% for one particular IGCC system (Chandra et al. 1978c).

Sulfur removal processes use a regenerable scrubbing solution and either produce salable by-product sulfur directly or a concentrated H_2S stream that can be converted to elemental sulfur using commercially proven processes. Most sulfur removal processes produce a tail gas containing H_2S , COS , and/or SO_2 . This tail gas will usually require treatment prior to venting. The treated tail gas will contain a relatively small amount of SO_2 that maybe vented to the stack.

Nitrogen oxides (NO_x) may be produced during combustion of the fuel gas. NO_x may be produced either by thermal fixation (reactions of N_2 and O_2 at high temperatures) or by oxidation of nitrogen compounds in the fuel gas. Measures

that may be taken to control NO_x emissions include removal of nitrogen compounds (primarily NH_3) from the gas prior to combustion, reduction of peak temperatures during combustion, and staged combustion techniques that limit the availability of oxygen during a portion of the combustion process.

Several references indicate that NO_x emissions from gas turbines burning LBG can be controlled to levels between 0.2 and 0.7 lb $\text{NO}_x/10^6$ Btu of fuel input (Tyson et al. 1997; Corman and Fox 1976; Foster-Pegg and Jaeger 1976; Murthy et al. 1977). Another reference (Crouch and Klapatch 1976) shows comparative emissions from LBG, IBG, and natural gas fired in a gas turbine combustor. The gases were all "clean" (i.e., they had been scrubbed to remove sulfur and nitrogen compounds). NO_x emissions with LBG were about one-third of those with natural gas firing. Because of the higher flame temperature for IBG, NO_x emissions were roughly 50% higher than those from natural gas. Emissions from IBG combustion were found to be effectively controlled either by premixing air and fuel or by adding water vapor to the fuel gas to reduce the flame temperature. These studies indicated that combustion of LBG or IBG in gas turbine combustors will comply with present exhaust emissions requirements. Actual emissions were not given.

Estimates of NO_x emissions from boilers fired with LBG range from 0.0015 to 0.015 lb $\text{NO}_x/10^6$ Btu fuel heat input (Tyson et al. 1977; Hale et al. 1977). Emissions with IBG will be higher; one reference estimates 0.15 lb/ 10^6 Btu (Tyson et al. 1977).

The particulate loading of the product gas is expected to be very low. Raw gas from the gasifier will usually contain only a fraction of the ash present in the feed coal. This fraction may be as low as 0.5% for fixed bed Lurgi gasifiers (Murthy et al. 1977). Ash content of fluidized bed and entrained gasifiers will run considerably higher - in some cases essentially 100% of the ash present in the feed coal. The initial cooling of the gas stream removes much of the particulate. Process steps that follow cooling typically include two or more scrubbing operations. Although little data are available, these multiple scrubbing operations should result in a very low

residual particulate loading. Data reported for the Koppers-Totzek process^(a) indicate that the particulate concentration is reduced to 0.002 grain/scf after the initial quench scrubber (Farnsworth et al. 1974). Additional reduction could be expected from subsequent chemical cleaning steps. For a gas with 300 Btu/scf heating value, 0.002 grains/scf corresponds to less than $0.001 \text{ lb}/10^6 \text{ Btu}$ or less than 4% of the $0.03 \text{ lb}/10^6 \text{ Btu}$ limit for coal-fired power plants.

Where the fuel gas is used in a turbine, very efficient particulate removal will be required to protect the turbine. If direct boiler firing of the gas is used, cleanup requirements are not so stringent and less efficient scrubbing may be used. Combustion Engineering estimates total particulate emissions of $0.05 \text{ lb}/10^6 \text{ Btu}$ when their gasification process is used with a gas-fired boiler (Hale et al. 1977).

Where coal- or char-fired boilers are used to provide process steam and auxiliary power for a coal gasification plant, they may be the primary source of particulate emissions. With IGCC systems, steam and power requirements are satisfied by the steam cycle to hold overall emissions of particulate matter to a low level. One study gives emission estimates for a $250 \times 10^6 \text{ scf/day}$ Lurgi gasification plant conceptually sited at Colstrip, Montana. This plant would emit negligible amounts of particulates and CO, 6.2 tons/day SO_2 , 5.9 tons/day NO_x , and 11.4 tons/day HC (U.S. EPA 1979).

The total volume of miscellaneous vent and purge gas streams is relatively small, and effluents in these streams should have little impact on total emissions. They will probably require some kind of treatment (e.g., incineration) for odor control.

Fugitive dust emission factors estimated for coal handling, processing and storage are $0.0068 \text{ lb/ton coal}$, $0.002 \text{ lb/ton coal}$ and 1.23 lb/acre , respectively (Blackwood and Peters 1976; PEDCO 1978).

(a) This is an entrained gasification process in which pulverized coal is reacted with steam and oxygen at high temperature. The coal is entrained in the gas and ~50% of the ash leaves the gasifier with the gas. The balance melts, runs down the walls, and flows out the bottom of the vessel.

4.4.2 Liquid Effluents

Liquid effluents from coal gasification-based electric power production options will be highly dependent on the process used. Because of the high operating temperature used with entrained flow gasifiers, organic materials in the coal will be essentially destroyed. The condensate from the gasification process will, therefore, not contain any oils, tars or phenols that can cause water pollution problems. In addition, some processes have unique features that greatly reduce liquid effluents from the gasification plant. For example, the Texaco process uses a water slurry to feed coal to the gasifier. Dirty condensate water produced when the gas is cooled may be recycled to the coal slurrying operation (a purge stream may be required to control buildup of soluble salts). The Combustion Engineering gasifier produces a relatively dry gas. Because of this, the cooling and scrubbing process is a net consumer of water (i.e., no condensate is produced). With the problem of condensate from raw gas cooling essentially eliminated in these processes, the major contaminated liquid streams will be those from the power cycle and will be similar to those from a conventional coal-fired power plant. These will include cooling tower blowdown, boiler blowdown, and storm runoff.

Waste water from the cooling tower and steam system will be reduced when an IGCC power plant is used rather than a totally steam-based system. This results from the smaller steam system and lower cooling tower heat rejection in the GCC system. Depending on the sulfur removal system used, there may be a small purge stream from this system that would require special treatment. Therefore, high temperature entrained gasification processes, such as Texaco and Combustion Engineering, do not appear to have any special water pollution problems and should have effluents that are no greater and probably less than a comparable coal-fired system.

Because of the low operating temperature in the drying and pyrolysis zones of the Lurgi and BGC gasifiers, a significant amount of organic material (tars, oils, phenols, etc.) is contained in the raw gas. As a consequence, the condensate water that is produced as the gas is cooled is highly contaminated. This condensate will require intensive treatment if it is to be discharged. Methods for treating this condensate have been surveyed and are discussed in

reports commissioned by EPA (Ghassemi et al. 1978a, 1978b, 1978c). Because of a lack of available data, the composition or flow rate of the treated condensate cannot be estimated. The available data and unknowns concerning disposal of liquid wastes from coal gasification plants are discussed by Murthy et al. (1977) and Ghassemi et al. (1978a, 1978b, 1978c). The condensate most likely can be adequately treated; however, the actual effluent characteristics with a given treatment system are unknown.

With the exception of the condensate from the raw gas, liquid effluents from gasification-based power plants using Lurgi or BGC gasification would be similar to those from plants using the Texaco or Combustion Engineering gasification process or conventional coal-fired power plants.

In an integrated gasification plant, many opportunities exist for recycle and reuse of process water. In several studies it has been proposed that the water be recycled to extinction, resulting in no liquid discharge at all. One way to accomplish this is to use extensive recycle and reuse of process streams coupled with conventional treatment of the recycle streams. A step must be included somewhere in the process to eliminate soluble salts and other impurities that are not removed by the conventional treatment systems. Operations proposed for this purpose include multiple effect evaporators, and use of a portion of the recycle water to control dust at an adjacent mine. While operation in the zero discharge mode will undoubtedly require additional development work and increased costs, it appears technically possible.

4.4.3 Solid Wastes

For most coal gasification processes, the solid wastes produced will consist mainly of ash from the feed coal. Other solid wastes requiring disposal include sludges from water treatment and acid gas removal, tar and oil sludges, and spent catalysts and absorbents. If limestone scrubbers are used to control SO₂ emissions from auxiliary boilers, a scrubber sludge will also be produced. This sludge would be similar to that produced in coal-fired power plants, although the amount produced would be substantially less because only a small fraction of the plant feed would be burned in the boilers.

Little data are available on the characteristics of the various solid waste streams. Properties of the ash will vary among processes. In the Texaco, BGC, and Combustion Engineering processes, the ash is exposed to temperature high enough to cause melting ("slagging"). In the Lurgi process, the temperature is controlled to prevent slagging or sintering of the ash. The slag is discharged as a granular material, which should be relatively inert and resistant to leaching. Ash from the Lurgi process should be similar to ash produced by coal combustion. With proper disposal techniques it should not pose any undue hazard.

Because the integrated gasification-based power production options will not require stack gas scrubbers, disposal of scrubber sludge will not be a problem, as it is with direct coal-fired systems. With the IGCC system, sulfur is removed prior to combustion of the gas using a regenerable scrubbing system. The sulfur compounds may then be converted to elemental sulfur, a salable by-product.

4.5 SUMMARY

Coal gasification provides an alternative method of producing a clean fuel for electric power production. All of the component subsystems for producing power via coal gasification are commercially available. However, these components have never been integrated into a large-scale plant for power production.

The estimated cost of LBG and IBG from coal ranges from \$3.13 to \$5.91/10⁶ Btu (1981 dollars) with feed coal priced at \$1.00/10⁶ Btu (see Table 4.3 for economic assumptions). The thermal efficiency of IBG and LBG production is estimated at 60% to 80%, depending on the process used.

HBG or SNG is expected to cost between \$6.42 and \$9.40/10⁶ Btu. The thermal efficiency of SNG production processes is estimated at 50% to 70%.

The cost of transporting SNG by pipeline is nominally \$0.13/10⁶ Btu/100 mi plus compressor fuel consumption and losses, which are estimated at approximately 0.2% to 0.3% of the gas flow per 100 miles. The cost of pipelining SNG compares favorably with other energy transportation options.

Because of the larger volume of gas that must be handled, the cost of pipelining IBG or LBG is expected to be at least three times that for SNG. It appears more economical to transport feed coal and make the gas near the point of use than to transport LBG or IBG over long distances.

Advanced gasification and power production processes are currently being developed that could potentially produce power at a lower cost than conventional coal combustion systems. Integrated coal gasification/gas turbine combined-cycle power plants show particular promise for reducing power cost and for improving thermal efficiency. These systems will require either shipment of coal to the load center or transmission of the power to the load center.

Emissions of SO_2 and NO_x can be controlled to levels as low as or lower than those from conventional coal combustion plants with scrubbers. Technology is available to reduce SO_2 emissions from gasification-based plants to very low levels; however, this adds significantly to the cost of power. Particulate emissions will be reduced to levels that are one to two orders of magnitude lower than current new source performance standards for coal-fired power plants. The advanced power conversion systems expected to be used with coal-derived fuel gases (e.g., gas turbines or fuel cells) will require significantly less water than conventional steam-electric systems.

The characteristics of solid and liquid wastes from coal gasification plants are process specific and are not well defined. Because of this, the environmental effects of these wastes cannot be predicted at the present time.

In any quantitative comparison of the coal gasification option, a key factor is the thermal efficiency of power production from the gas. Among developing technologies this efficiency varies considerably, with the most efficient processes or operating conditions typically requiring the largest advance in the state-of-the-art. Advanced gasification and power conversion systems are expected to make use of IBG or LBG economical for baseload power production within the next ten years (EPRI 1982). However, because of its high production cost, use of SNG most likely will not be economical for baseload power generation even with the most advanced power conversion systems.

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5.0 COAL-FIRED STEAM-ELECTRIC POWER GENERATION

The technology, cost, resource consumption and environmental aspects of large-scale, coal-fired power production are described in this chapter. Power production based on Northern Great Plains coal reserves is the focus of this discussion. Effects of minemouth and Midwestern load center plant siting are described.

In the first section, the technology of conventional coal-fired power generation using subbituminous coal is described. Major subsections concerning air pollution control technologies and condenser cooling systems are included. Performance characteristics of large coal-fired electric power plants are also discussed in this section. Plant efficiency, reliability, availability and capacity factor are defined and described. Energy resource consumption and major material requirements are addressed in the second section. Land, water, energy, and material consumption for large coal-fired power plants are outlined. Power plant costs are characterized in the third section. Capital, operating and fuel costs for both Western and Midwestern plant locations are estimated. This cost information provides the basis for calculating busbar energy cost. Environmental impacts of the generation process are outlined in the final section of this chapter. Pertinent air- and water-quality regulations are summarized and aggregate annual emissions and effluents are estimated. More detailed discussions of air- and water-quality regulations affecting power plant design are presented in Appendix A.

5.1 TECHNOLOGY DESCRIPTION

This discussion will focus on the aspects of the generation process affected by combustion of Western subbituminous coal and Western and Midwestern plant locations. A comprehensive discussion of the technical aspects of the steam-electric generation process is not intended.

Contemporary coal-fired, steam-electric power plants can be divided into five major systems:

- boiler plant
- turbine plant
- electric plant
- air pollution control
- condenser cooling.

Although air pollution control systems and condenser cooling systems are often included as part of the boiler plant and turbine plant, respectively, they are separated here because several alternative technologies are available for each system. Major power plant components are shown in Figure 5.1.

FIGURE 5.1. Power Plant Components

Descriptions of the boiler plant, turbine plant and electric plant are presented below, followed by an evaluation of system characteristics. Air

pollution control systems and cooling systems are examined to determine their impacts on the cost and efficiency of the generation process.

5.1.1 Boiler Plant

The boiler plant includes facilities for coal handling and preparation, plus the boiler itself. Coal handling and preparation facilities include facilities for receiving, handling and storing raw coal and equipment for preparing the coal for firing. The type of coal-receiving facilities used depends greatly upon the mode of transportation used for coal delivery. These facilities are discussed in Chapter 3 of this report. A sixty-day coal supply is typically stored in uncovered piles, but shorter-term storage could be provided by silos.

Coal is prepared for firing by grinding it in pulverizers to the degree of fineness required by the firing method. Most contemporary central stations use pulverized (suspension) firing, requiring coal to be ground to a fineness of approximately 200 mesh.^(a) Cyclone furnace firing, less common than pulverized firing, uses coal of approximately 4 mesh consistency.

Important components of large boilers are shown in Figure 5.2 and include:

- furnace - The furnace burns coal to produce heat for steam production. Heat is transferred by radiation to water tubes that form the furnace walls, and saturated steam is produced. Most large coal-fired boilers use either pulverized firing or cyclone firing.
- superheaters (primary and secondary) - Superheaters are a series of tubes in which saturated steam is heated by combustion gases to superheated condition. Superheaters may be located near the top of the boiler or in the convection pass.
- reheater - Partially expanded steam is taken from high-pressure stages of the turbine and heated in a bank of tubes. The reheated steam is then returned to low-pressure stages of the turbine. Several reheat cycles may be used.

(a) Mesh is defined as the number of screen openings per linear inch.

FIGURE 5.2. Boiler Components

- economizer - Heat is exchanged in the economizer from the flue gases to the boiler feedwater.
- air heater - The air heater transfers heat from the flue gases to the combustion air.

Once combustion gases transfer heat to the boiler tubing and various boiler components, about 90% of the heat has been used.

Conventional methods of burning coal in large utility boilers have changed with the expanded use of subbituminous and lignite coals. The higher moisture, lower Btu content, and different ash composition of these lower rank coals have brought about design modifications for boilers and combustion systems. In addition to modifications caused by alternate fuels, air pollution regulations, particularly for nitrogen oxides (NO_x), have affected firing techniques. Optimal boiler design, therefore, depends on the specific

characteristics of the coal to be burned and on the emission limits of pollutants. However, because coal quality varies (even within a region) and new air pollution regulations are uncertain, the key to successful boiler design is flexibility of operation.

Combustion Options

Conventional firing techniques for large utility boilers are pulverized coal firing and cyclone firing. In pulverized coal firing, coal is pulverized to allow 65 to 80% to pass through 200 mesh and dried with preheated air to reduce the coal's moisture content. The pulverized coal then leaves the pulverizer and is mixed with the primary air. The coal/air mixture is introduced into the furnace through burners, where additional secondary air is supplied to aid combustion.

In cyclone (slag tap) furnaces tangentially fired air creates a whirling motion in which the crushed coal is ignited and burned at very high temperatures. The fly ash, which is dispersed in boilers using pulverized coal firing, forms a molten slag in slag tap furnaces that can be tapped from the furnace.

Cyclone furnaces offer several advantages over pulverized coal-fired furnaces when low rank coals are burned. Fly ash from low sulfur coals, which responds poorly in electrostatic precipitators, can be removed from the cyclone furnace in the form of a molten slag. Slagging and fouling, which could reduce boiler efficiency, are also reduced. In addition, because of lower auxiliary energy requirements, cyclone furnaces may be less costly to operate than pulverized coal-fired furnaces for low rank coals. Figure 5.3 shows that for subbituminous and lignite coals, the auxiliary power requirements for pulverized coal firing are greater than those for cyclone firing. However, this is not the case with bituminous coals, which use less auxiliary power by pulverized coal firing. Also, most eastern bituminous coal cannot be used in a cyclone furnace due to high ash melting temperatures, whereas most western coal meets this constraint.

Because cyclone furnaces operate at very high temperatures, NO_x emissions are difficult to control. Many cyclone furnaces could not meet previous New

FIGURE 5.3. Auxiliary Energy Requirements for Large-Scale Combustion Systems (Babcock and Wilcox 1978)

Source Performance Standards (NSPS) (Table 5.1) that establish a maximum of 0.7 lb NO_x/10⁶ Btu for all coals, and their use has subsequently dropped off sharply. The current NSPS, however, discriminate between the type of coal used and the maximum allowable NO_x emissions. For Northern Great Plains lignite coal, limits have been extended to a 0.8 lb NO_x/10⁶ Btu maximum when burned in slag tap furnaces. Limits for subbituminous coal, however, have been reduced to a 0.5 lb NO_x/10⁶ Btu maximum, confining combustion of this coal type to pulverized coal-fired furnaces.

Fluidized-bed combustion is under development as an alternative to conventional combustion methods. In this system, coal is introduced into a turbulent bed of limestone or other type of noncombustible material. The

TABLE 5.1. New Source Performance Standards (NSPS)

Pollutants	Existing ^(a)		Previous ^(b)	
	Emissions Ceiling	Minimum Reduction of Uncontrolled Emissions	Emissions Ceiling	Minimum Reduction of Uncontrolled Emissions
Particulates:	0.03 lb/10 ⁶ Btu	99%	0.1 lb/10 ⁶ Btu	None
NO _x :			0.7 lb/10 ⁶ Btu	None
- Subbituminous Coal	0.5 lb/10 ⁶ Btu	65%	(All Coals)	
- Bituminous Coal	0.6 lb/10 ⁶ Btu	65%		
- Northern Great Plains Lignite Burned in Slag Tap Furnaces	0.8 lb/10 ⁶ Btu	None		
SO ₂ :			1.2 lb/10 ⁶ Btu	None
- 0-2 lb/10 ⁶ Btu Potential	1.2 lb/10 ⁶ Btu	70%	(All Coals)	
- 2-6 lb/10 ⁶ Btu Potential	1.2 lb/10 ⁶ Btu	70%-90%		
- 6-12 lb/10 ⁶ Btu Potential	1.2 lb/10 ⁶ Btu	90%		
- Greater than 12 lb/10 ⁶ Btu Potential	1.2 lb/10 ⁶ Btu	--		

(a) Environment Reporter June 30, 1978, and Allen and Kaslow 1979.

(b) 40 CFR 60.42-45.

limestone bed is transformed into a fluid medium by air that is introduced beneath the limestone. The air used for fluidizing the limestone is also sufficient for combustion air requirements. Due to low combustion temperatures (2000°F), boiler tubes may be embedded directly in the fluidized bed, improving heat transfer.

The fluidized-bed boiler offers several advantages over conventional boilers. First, since boiler tubes are embedded directly in the combustion zone, fluidized bed boilers are much smaller than conventional units and may even be delivered as package units. Second, sulfur in the coal reacts with the limestone to produce CaSO_4 , reducing emissions of sulfur dioxide (SO_2). Third, NO_x emissions are low because combustion occurs at low and uniform temperatures throughout the boiler (University of Oklahoma 1975).

Currently, two major designs of fluidized-bed boilers exist--pressurized bed and atmosphere bed. As the names suggest, the main difference is the pressure used in the boiler during combustion. Atmospheric pressure fluidized-bed boilers are offered commercially for industrial applications only by Foster Wheeler, Combustion Engineering, Babcock & Wilcox, Pope, Evans and Robbins, Inc., and FCC Limited. Pressurized fluidized-bed boilers are still developmental.

Several technical problems still exist before fluidized-bed boilers will be available for utility application. Problems encountered by Babcock & Wilcox in testing of their atmospheric fluidized-bed boiler include warping of distribution plates, overall wear problems, swaying and vibration, ash handling, and controls (Bonk et al. 1979). Problems with coal distribution, system controls and long-term corrosion/erosion were identified as technical constraints to utility application in tests conducted by TVA (Falkenberry et al. 1979). Commercial availability of utility-size fluidized-bed boilers is expected in the early 1990s.

Design Considerations for Use of Subbituminous Coal

Certain conventional design characteristics of the boiler and pulverizer change when subbituminous coal is burned. Table 5.2 shows relative mill sizes

TABLE 5.2. Relative Mill Sizes for Various Coals^{(a)(b)}

	<u>Eastern Bituminous</u>	<u>Midwestern Bituminous</u>	<u>Subbitumi- nous</u>	<u>Texas Lignite</u>	<u>Northern Great Plains Lignite</u>
Hardgrove Grindability Index	55	56	43	48	35
Number of Mills Required	6	6	6	6	7
Nominal Capacity (T/hr)	50	63	85	92	100
Primary Air Temperature for Drying Coal (°F)	525	640	725	750	750

(a) Hensel and Harris 1978.

(b) Mill selection based on one full spare with remaining mills at 90% of full capacity.

and drying temperatures required in the pulverizing operation for various coals. As the rank of the coal decreases and moisture increases, larger mills and higher drying temperatures are required for the same power output.

Pulverizer size and drying temperature requirements are a function of the coal's moisture content, heat content, and grindability. The moisture of subbituminous Wyoming coal is about 20% by weight compared to 6% for Eastern bituminous coal. The heat content of subbituminous coal (roughly 9,000 Btu/lb) is about three quarters that of bituminous coal. The Hardgrove grindability index, a measure of the relative ease of pulverization, is low for subbituminous coal, reflecting poorer grindability than bituminous coals. These three factors all contribute to greater pulverizer requirements and associated costs for subbituminous coal.

Another design consideration is the relative boiler size for different coal types. The difference in size is attributed mainly to the difference in slagging and fouling potential. Slagging is the formation of molten ash deposits on boiler walls caused when fused or partially fused ash particles in

the combustion gas condense and solidify on walls and tubes. Fouling is caused by volatile constituents in coal ash, mainly sodium and potassium compounds condensing on reheater and superheater tubing in areas not exposed to radiant heat (Figure 5.4).

FIGURE 5.4. Slagging and Fouling Areas in Boilers

Slagging, characteristic of Western coals with low ash fusion temperatures, can be controlled by allowing ash particles to cool before contacting boiler surfaces. In addition, fouling is reduced if the combustion gases are allowed to cool prior to the convection pass. Alternate spacing of superheater and reheater tubing can also be used to help control fouling (Heil and Durrant 1978).

Figure 5.5 shows relative boiler sizes for low, medium, high, and severe slagging coal. Although these slagging conditions usually correlate to coal types listed in Figure 5.5, this is not always the case. One major boiler manufacturer has estimated that the difference in installed boiler costs (allowing for convection surface differences and additional soot blowers) between a boiler designed for low to medium slagging potential and one for severe slagging potential is about \$4 to \$4.5/kW.

FIGURE 5.5. Relative Boiler Sizes (Hensel and Harris 1978)

Slagging and fouling can reduce boiler efficiency and availability. Slag formation on boiler tubing acts as insulation and can cause an increase in steam temperatures and the formation of deposits in normally cooler portions of the boiler (Babcock & Wilcox 1978). Large deposits may fall and damage boiler components. Accumulation of deposits on convection pass tube banks can

block gas passes and require shutdown for manual cleaning. The need to remove slag deposits increases maintenance cost and downtime.

Emission Control Considerations

Although most emission control occurs after combustion, some control is incorporated into the combustion process.

NO_x Control. Due to additional moisture and lower levels of fuel nitrogen present in subbituminous coal, the amount of NO_x in the combustion gases is lower than for coals of higher rank. This is reflected in the current Environmental Protection Agency (EPA) New Source Performance Standards (NSPS) that require lower NO_x emissions for subbituminous coals (0.5 lb/10⁶ Btu) than for bituminous coals (0.6 lb/10⁶ Btu) (Table 5.1).

Unlike sulfur oxides (SO_x), NO_x cannot be easily removed from flue gases by scrubbing. Instead, NO_x formation is controlled by flame temperature, furnace configuration and the amount of oxygen present during combustion. Staged firing is the main method for controlling NO_x emissions because it does not require major modifications in boiler design. Staged firing involves initial combustion of coal in a fuel-rich environment with subsequent addition of air to complete combustion. This method requires a careful balance between withholding air to reduce NO_x emissions and supplying air to complete combustion. Incomplete combustion of coal particulates could increase fuel cost (Graham 1976).

An alternative to staged firing is the dual register burner developed by Babcock & Wilcox. The dual register burner reduces NO_x formation by prolonging combustion and thereby lowering combustion temperatures. This reduces NO_x formation and minimizes slagging while providing better carbon use than staged firing. The dual register burner may produce as much as 60% less NO_x emissions than circular burners for subbituminous coal in units of 700 MW capacity (Campobenedetto 1978).

Although both the dual register burner and staged-firing techniques can meet the current 0.5 lb NO_x/10⁶ Btu NSPS emission limit for subbituminous coal, further reduction of NO_x emissions standards may be proposed. An objective of one EPA research program is to demonstrate that NO_x can be

controlled to 100 parts per million (ppm) NO_x at 3% O_2 or about $0.15 \text{ lbs } \text{NO}_x / 10^6 \text{ Btu}$ by 1985 (Johnson, Cioffi and McElroy 1978). New technologies for reducing NO_x emissions may be required if standards are lowered. New technologies could result in increased costs, decreased efficiency and decreased reliability.

SO_2 Control. Most SO_2 removal currently occurs after combustion. Any of several flue-gas desulfurization processes may be used to remove SO_2 from the flue gas. Under recent EPA proposals, credit will be given for sulfur removal prior to combustion. However, the manner in which the EPA will implement this plan is uncertain at this time.

In-furnace removal of SO_2 may be accomplished by adding limestone during combustion. However, this method, limestone boiler injection, was tested by the Tennessee Valley Authority (TVA) at their Shawnee power plant and was found to be an ineffective means of SO_2 control due to boiler fouling and low removal efficiencies (Gartrell 1977). Eventual commercialization of fluidized-bed combustion may provide effective in-furnace control of SO_2 .

5.1.2 Turbine Plant

The theoretical upper limit on thermal efficiency for a steam turbine is determined by the Carnot cycle efficiency. With a inlet temperature of 1200°F and a condensate temperature of 90°F , the theoretical efficiency of a steam turbine is about 67%. However, with current technology, 1000°F is the maximum practical steam inlet temperature and after accounting for losses, a thermal efficiency of 45% is considered good.

Turbine efficiency could be increased by higher inlet temperatures; however, the maximum steam inlet temperature is constrained by metallurgical limits of the piping and turbine blades. Increases in throttle temperatures above 1000°F increase forced outage rates and decrease availability (Elston 1976). Significant increases in turbine efficiency are not expected in the near future.

Contemporary coal-fired central station steam-electric plants are designed for nominal steam pressures of 1450 to 3500 psi with superheater and

reheat temperatures of 950 to 1000°F. Although a single reheat cycle is typical, multiple reheats can be used to achieve higher efficiencies (but at greater cost). A 3500 psi 1000°F/1000°F plant will have a turbine efficiency of approximately 45%. Use of subbituminous coal does not directly affect the operation of the turbine.

5.1.3 Electric Plant

Generators have been developed to a high state of technology, and efficiencies of 98% are common. Generators of the 3600 rpm, 3-phase synchronous type are in common use for fossil fuel-fired power plants.

5.1.4 Air Pollution Control Systems

Fly ash, SO_x , and NO_x are the principal constituents of stack gases requiring control. Stack gases may also contain carbon monoxide (CO) and unburned hydrocarbons, although these are avoided by proper furnace operation. Formerly, particulates (fly ash) were controlled by cyclone separators and later, electrostatic precipitators, to produce a clear stack discharge. The advent of pulverized coal firing resulted in a much larger proportion of ash contained in the flue gas, requiring greater particulate removal capability. Increases in the number and size of pollutant sources required more comprehensive and sophisticated stack gas emission control to maintain acceptable levels of atmospheric quality. Current air-quality regulations require control of particulates, SO_x , and NO_x to standard levels.

Air-Quality Regulations

The allowable emissions from new electric power plants are regulated by the Clean Air Act of 1970 and its subsequent amendments. Three important sections of the act are the New Source Performance Standards (NSPS), the State Implementation Plans (SIP) of the National Ambient Air Quality Standards (NAAQS), and the Prevention of Significant Deterioration (PSD) regulations. The impacts of these regulations on the power generation system are summarized below. A more detailed discussion of air-quality regulations is presented in Appendix A.

The NSPS were established to control emissions from new stationary power-generating facilities by instituting Best Available Control Technology as determined by the EPA. The current NSPS, summarized in Table 5.1, limit emissions of SO_2 , NO_x , and particulates and require power system modifications to achieve compliance. The NSPS require the use of flue-gas desulfurization equipment on all coal-fired power plants for SO_2 removal. Capital costs for desulfurization equipment account for approximately 10 to 15% of total plant capital costs.

The NSPS will also require greater particulate removal than did previous regulations. However, since coal-fired plants had to remove particulates under previous regulations, the existing NSPS do not pose significant technical problems. Additional costs will be borne by utilities to comply with these standards.

Emissions of NO_x must be controlled to a greater degree but will not require major modifications of the plant structure. In most cases, NO_x can be successfully controlled by alternate combustion techniques.

The SIP is developed by individual states to comply with the NAAQS. Standards vary from state to state, with most states having standards that are equal to or less stringent than the NSPS (in the latter case the NSPS establish the required level of control). However, a few states have standards that are more severe than the NSPS and that would require additional air pollution control.

Perhaps the most restricting air-quality regulation is the PSD requirements. The PSD regulations are designed to protect areas with low existing pollution levels from being polluted up to the NAAQS. Under PSD regulations, areas having pollutant concentrations less than the NAAQS are allotted additional pollution increments based on an area's air-quality classification and existing pollution levels. These increments must be shared by all new or redesigned industries and utilities. Although it is uncertain how states will eventually allocate PSD increments, locations for coal-fired power plants, especially multiple sitings, most likely will be severely limited.

Power Plant Emissions

The NAAQS require control of the following six pollutants:

- particulates
- sulfur oxides
- photochemical oxidants
- hydrocarbons
- nitrogen oxides
- carbon monoxide.

Table 5.3 lists typical uncontrolled emissions for a coal-fired power plant. Units are expressed in pounds of pollutant emitted per ton of coal burned, except for radioactive gases, which are expressed in curies per ton of coal burned. To determine the control required to meet federal and state emissions standards, the heat, sulfur and ash content of the coal must be known.

TABLE 5.3. Uncontrolled Emissions From Coal-Fired Power Plants^(a)

<u>Air Pollutants</u>	<u>lb/Ton Burned</u>
Particulates	16A ^(b)
SO ₂	38S ^(c)
NO _x	18
Hydrocarbons	0.3
CO	1.0
Radioactive Gases (²²⁶ Ra, ²²⁸ Ra)	0.028 ^(d)

(a) Cirillo et al. 1977.

(b) A = % ash by weight.

(c) S = % sulfur by weight.

(d) Expressed in curies based on a
1000 MW plant @ 80% capacity.

Of the six pollutants for which NAAQS are established, SO_2 , NO_x , and particulates require emission control on coal-fired power plants. SO_2 and particulates can be controlled by removal processes, whereas NO_x is controlled through combustion techniques.

Particulate Control. Electrostatic precipitators, fabric filters (baghouses) and scrubbers have been the three major particulate removal techniques used on U.S. fossil fuel plants. The most widely used system is electrostatic precipitators, which capture particulates by creating an electric field between metal plates that the fly ash particles are attracted to. Collection is accomplished by mechanical striking of the plates. Collection efficiencies for electrostatic precipitators can be very high, about 99.9% removal.

Power plants fueled by Western coal, however, have encountered collection problems with precipitators due to high fly ash resistivity of low sulfur coals. Resistivity varies with both the flue gas temperature and the sulfur content of the coal (Figure 5.6). To improve precipitator performance when using low sulfur coals, precipitators are installed on the "hot" side of the air preheater (instead of the conventional "cold" side installation), and the specific collection area of the plates is increased.

Precipitators have been the dominant method of particulate control due to relatively low capital and operating costs. However, their additional cost and reduced reliability when used on power plants burning low sulfur coal have caused a trend towards baghouses. Baghouses use mechanical filtration by fabric filters to capture particulates and are therefore not affected by fly ash resistivity. As with precipitators, the collection efficiency of fabric filters can reach 99.9%.

The Electric Power Research Institute (EPRI) has conducted a series of tests comparing collection efficiencies of three electrostatic precipitators and one baghouse over a range of particle sizes (Carr, Piulle and Gooch 1977). Plants 1 and 2 used cold side precipitators with large specific collection areas, whereas Plant 3 used a hot side precipitator. A fourth plant was equipped with a baghouse. The test concluded that the baghouse had

FIGURE 5.6. Fly Ash Resistivity as a Function of Temperature and Sulfur Content (Ctvrtnicek, Rusek and Sandy 1975)

removal efficiencies equal to or greater than the precipitators. The baghouse had a particular advantage over precipitators for the removal of small particles ($<1\mu$).

Some SO_2 removal techniques, particularly nonregenerative methods, can remove a high percentage of particulates in conjunction with the normal scrubbing process. No clear choice exists between scrubbing specifically for

particulate removal and using precipitators. However, economic advantages may exist when scrubbing for SO_2 removal is done simultaneously with particulate removal.

Previously, the NSPS required emissions of particulates to be no more than $0.1 \text{ lb}/10^6 \text{ Btu}$. A typical Western coal with 10% ash and 9,000 Btu/lb requires 99% particulate removal to meet this standard. Scrubbers would probably be capable of 99% particulate removal. However, scrubbers, alone, would probably not be able to meet the current NSPS for particulates of $0.03 \text{ lb}/10^6 \text{ Btu}$, which would require 99.7% removal for the same coal. Many power plants most likely will require supplementary particulate removal using baghouses or precipitators upstream or downstream of the scrubber. However, the combination of particulate removal method with subsequent SO_2 scrubbing that would be required to obtain 99.7% particulate removal is not certain.

SO_2 Removal. SO_2 emissions can be controlled by reducing the sulfur content of the coal, by using combustion additives or by removing SO_2 from the flue gas (flue-gas desulfurization). Although as many as 50 types of SO_2 removal systems have been proposed, two systems, wet lime and wet limestone slurry scrubbing, account for the majority of installations in U.S. power plants (FERC 1977). Nine operable or near-operable removal options suitable for large generating units are discussed below. A comparison of five of these systems is presented in Table 5.4.

Flue gas desulfurization (FGD) methods are classified either as throwaway (nonregenerative) or recovery (regenerative). Throwaway processes produce a waste stream of calcium solids that must be dewatered and disposed of. In contrast, recovery methods produce a salable by-product (usually sulfur or sulfuric acid). Throwaway methods currently in commercial use are shown in Figure 5.7 and include lime/limestone slurry scrubbing, alkaline fly ash scrubbing, double alkali scrubbing and sodium carbonate absorption. Recovery methods in commercial use are shown in Figure 5.8 and include magnesium oxide scrubbing, sodium solution scrubbing and catalytic oxidation. By far the most widely used FGD processes are the lime and limestone scrubbing processes.

TABLE 5.4. Comparison of Major SO₂ Removal Systems^(a)

	Removal	Capital Costs ^(b) (\$/kW) 1981		Operating Costs ^(b) (\$/kW) 1981		Energy Penalty (Btu/kWh)	Annual Process Water (10 ⁶ gal)	Annual Raw Material Requirements 3.5% Sulfur
		3.5% S	1% S	3.5% S	1% S			
Limestone Slurry	85-90%	69.5	58.4	21.9	17.0	360	484	338,400 tons limestone
Lime Slurry	85-90%	60.4	50.7	23.2	17.8	345	468	157,000 tons lime
Magnesium Oxide	90%	71.6	56.5	26.5	18.8	530	4,270	259 tons lime 2,078 tons magnesium oxide 1,475 tons coke 3,480 lb catalyst
Sodium Scrubbing	>90%	84.5	65.0	33.8	22.0	1,040	19,240	259.2 tons lime 18,000 tons soda ash 613,000 lbs anti-oxidant
Catalytic	>90%	128.7	126.2	25.7	25.4	11	600	202,000 lb catalyst

(a) McGlamery et al. 1975. Assumes 1000 MW power plant at 80% capacity factor.

(b) Costs are estimates based on data from McGlamery et al. 1975, and Handy-Whitman 1982.

FIGURE 5.7. Nonregenerative FGD Systems (FPC 1977b)

FIGURE 5.8. Regenerative FGD Systems (FPC 1977B)

Recovery processes have been used less widely because of high capital and operating costs and a limited market for by-products. Nonregenerative and regenerative processes are described below:

- boiler injection - Of the systems considered, limestone boiler injection is the only system that desulfurizes the flue gas before it leaves the boiler. Limestone boiler injection is based on addition of limestone into the boiler during combustion. The limestone (CaCO_3) is calcined to lime (CaO) and is carried in the exhaust gases to the scrubber where calcium salts are formed and removed as solid waste. The main advantages of this method are the low capital investment and simplicity of operation. The main disadvantages are low removal efficiency (50%) and slagging and fouling problems in the boiler. No limestone injection systems are currently installed on commercial power plants and this method is not expected to be applied to large generating units in the near future.
- wet lime/limestone scrubbing - The most widely used FGD process involves scrubbing of the flue gas with a lime or limestone slurry, forming insoluble calcium sulfites and sulfates that are disposed of as solid waste (Figure 5.7). About 75% of all FGD installations on U.S. power plants are either wet lime or wet limestone scrubbing (FPC 1977b). The lime/limestone slurry process is the most advanced removal system and can remove 99% of particulates and 90% SO_2 at lower cost and greater reliability than other systems. Limestone scrubbing entails a higher capital cost but lower operating cost than lime slurry scrubbing.
- dry scrubbing - Dry scrubbing systems have several advantages over wet lime/limestone scrubbing systems. The principal advantage is the volume reduction of the wastes to be disposed of. This is particularly important at load center power plants where disposal sites may be distant and land costs high. Another advantage is

reduced water demand. This may be more important to power plants in the semiarid west. With dry scrubbers, reactant is blown into the flue gas in the form of a dry powder or sprayed in the form of a thick slurry. In the slurry case, water is evaporated by the hot flue gas, and in either case the sulfur salts are collected as particulates. A variation of dry scrubbing involves coating fabric filters with reactant.

Dry scrubbing systems are most suitable for use with low sulfur coals. Two systems have been developed, one using lime and one using soda ash. When used for low sulfur coal, these spray dryer systems have comparable overall cost and lower initial investment compared to a limestone slurry system. Based on an analysis by TVA, unit investment costs for dry systems can be 10 to 12% lower than limestone systems (Rittenhouse 1981).

- alkaline fly ash scrubbing - Some Western subbituminous coals contain large amounts of calcium (expressed as CaO) and magnesium (expressed as MgO). The high alkaline ash from these coals can be used as an SO_2 scrubbing agent. The removal process is similar to wet lime/limestone scrubbing except that ash is used as the main scrubbing agent and lime or limestone is used as either a supplemental alkali or to control pH (Figure 5.7)(FPC 1977b). Therefore, raw material requirements for lime and limestone are reduced.

Table 5.5 gives the removal efficiencies and availability of seven alkaline fly ash scrubber systems currently operating on power plants burning subbituminous coal. Most plants scrubbed for particulate removal only, but achieved as high as 50% SO_2 removal from the alkalinity of the ash alone. In most cases lime or limestone was used to control the pH of the slurry rather than to increase alkali requirements (LaMantia et al. 1977).

Only a few operating U.S. plants use a lime/fly ash scrubbing system specifically for SO_2 control. However, power plants burning

TABLE 5.5. Selected Power Plants Using Alkali Fly Ash Scrubbing^(a)

Power Plant ^(b) And Location	Capacity MW	Control ^(c)	SO ₂ Removal	Particulate Removal	Supplimentary Alkali	Start-up Date	Availability	Comments
Colstrip 1 & 2 Montana	360 each	P, SO ₂	80-85%	99.6%	Lime	#1 - 9/75 #2 - 5/76	High (long term)	Lime for pH control.
Sherburne Co. 1 & 2 Montana	680 each	P, SO ₂	50%	99%	Limestone	#1 - 3/76 #2 - 5/77	>95% (extended periods)	—
Four Corners Plant 1,2&3, New Mexico	175,175 225	P	30-35%	99.8%	Lime	#1 - 12/71 #2 - 12/71 #3 - 1/72	60-70% over extended periods	Lime for pH control. availability for boiler and scrubber.
Dave Johnson 4 Wyoming	330	P	40%	99%	Lime	4/72	"Less than adequate"	Lime for pH control.
Valmont 5 Colorado	166	P	50%	97%	None	11/71	57% (56 months)	—
Aurora 1 & 2 Minnesota	58 each	P	37%	98%	None	6/71	100% (can be maintained during operation)	—
Clay Boswell 3 Minnesota	350	P	37%	99%	None	5/73	100% (can be maintained during operation)	—

(a) LaMantia et al. 1977.

(b) All plants burn subbituminous coal.

(c) P = Particulates; SO₂ = sulfur dioxide.

subbituminous coal and choosing to scrub with lime or limestone can be expected to use the high alkaline fly ash as an additional scrubbing agent.

- double alkali scrubbing - Several variations of this process involve the scrubbing of flue gases with a clear liquor of sodium or ammonium salts (Figure 5.7). Subsequent treatment of the spent liquor with lime produces waste calcium salts and regenerates the alkali liquor. The double alkali process is not as highly developed as the lime/limestone systems, but it has the potential for high removal efficiencies at low cost (FPC 1977b). Currently, one power plant in the U.S. uses double alkali scrubbing; three others are under construction or committed (FERC 1977). This process has had more acceptance in industrial applications.
- sodium carbonate absorption - The sodium carbonate process is based on SO_2 absorption by sodium carbonate (Na_2CO_3) (Figure 5.7). This process is nonregenerable and can use common trona ($\text{Na}_2\text{CO}_3 \cdot \text{NaHCO}_3 \cdot 2\text{H}_2\text{O}$) as the primary absorbent. The advantages of this method are the highly soluble properties and easy extractability of sodium carbonate. The disadvantages include the limited availability of sodium carbonate and the large quantities of effluent that are produced (FPC 1977b). Three plants using sodium carbonate scrubbing are currently in operation in the U.S. and a fourth is under construction (FERC 1977).
- magnesium oxide scrubbing - Magnesium oxide scrubbing is a recovery process similar to lime/limestone scrubbing except that it uses magnesium oxide as the scrubbing agent. Spent magnesium salts are regenerated to magnesium oxide (Figure 5.8), producing a concentrated stream of 10 to 15% SO_2 that can be converted to either concentrated sulfuric acid or elemental sulfur. Aside from high costs, this system requires 90% particulate removal prior to scrubbing (FPC 1977b). One plant in the U.S. uses magnesium oxide scrubbing; no additional plants using this process are under construction or committed (FERC 1977).

- sodium solution scrubbing - Sodium solution scrubbing (the Wellman-Lord process) uses a solution of sodium sulfite, bisulfite and sulfate to scrub the flue gases (Figure 5.8). A concentrated stream of SO_2 that can be processed to sulfur or sulfuric acid is produced. The advantages include simplicity of operation and higher reliability compared to magnesium oxide scrubbing. The main disadvantages are high costs, requirements for particulate removal prior to scrubbing, and large quantities of make-up water (FPC 1977b). One plant in the U.S. currently uses the Wellman-Lord process and two others are under construction (FERC 1977).
- catalytic oxidation - Catalytic oxidation uses a fixed catalyst bed where SO_2 is oxidized to SO_3 and then absorbed into a recirculating stream of sulfuric acid (Figure 5.8). This process requires high temperatures and high particulate removal (99.9%) prior to oxidation (FPC 1977b). Although this method has low labor and energy costs, capital costs are high. In addition, average operating costs decrease only slightly with decreasing sulfur content of the coal, making this method less desirable for low sulfur coals (McGlamery 1975). A 110 MW plant used catalytic oxidation but has since shut down due to mechanical troubles (FERC 1977).

NO_x Control. Under current air-quality standards, NO_x control can be achieved by preventing its formation rather than by scrubbing the flue gas. NO_x formation can be prevented by staged firing or with dual register burners (p. 5.12). If NO_x scrubbing of the flue gas becomes necessary due to stricter air-quality laws, capital costs of NO_x scrubbing systems are estimated to range from \$60 to \$90/kW (Rosenberg et al. 1978)

Trace Element Emissions. Currently, no emission standards for trace elements are applicable to power plants. Typical emission rates for sixteen selected trace elements are presented in Section 5.4.

Performance Effects of Flue-Gas Desulfurization Equipment

Because each FGD process requires some energy input, overall system efficiency decreases when these units are added. Table 5.4 shows incremental Btu penalties that are added to the plant heat rate. A 1000 MW power plant with a 70% capacity factor burning 9,100 Btu coal would need to consume an additional 121,000 tons of coal per year to provide energy for operation of a limestone scrubber. Another effect that FGD systems have on the generation process is a decrease in availability. Scaling, plugging, and corrosion of scrubbing systems will interrupt normal operations. Availability for FGD systems has ranged from below 50% to over 90% (Table 5.5). Reduced availability in FGD systems will, in turn, reduce total power plant availability.

Other considerations in the operation of FGD systems include disposal of scrubbing wastes and leaching of these wastes into groundwater. Disposal of solid wastes from coal-fired plants is regulated by the Resource Conservation and Recovery Act of 1976. Waste disposal alternatives and solid waste disposal regulations are addressed in Section 5.4.

With few power plants in the U.S. currently using FGD systems (~50), generalizing about costs is difficult. Location, plant size, coal type, and system selection all contribute significantly to the cost of an FGD system. However, accounting for both direct and indirect cost elements, an FGD system represents approximately 10 to 15% of the capital cost of a coal-fired power plant.

Based on data from the EPA and TVA, Table 5.4 gives the estimated capital and operating costs for five FGD systems (McGlamery et al. 1975). These data were escalated to 1981 dollars and adjusted for scrubbing 1% sulfur coal.

Costs for wet lime and limestone systems are documented better than other systems due to the greater number of these systems in operation. However, documented capital costs of these systems vary widely from \$50 to \$145/kW (FPC 1977b). Table 5.6 gives adjusted capital cost data for several operating FGD systems. The variation in FGD cost can be attributed to differences in

TABLE 5.6. Adjusted Cost Data for Operating FGD Units^(a)

	New or Retrofit	Size MW	Capital ^(b) Costs (\$/KW)	Sulfur in Coal %	Replacement ^(b) Capacity Cost (\$/KW)	Total ^(b) Capital Cost (\$/KW)	System Type
Duquesne Light, Elrama Units 1-4	R	494	118	1.0-2.8	19	137	Lime
Duquesne Light, Phillips Units 1-5	R	387	136	1.0-2.8	20	156	Lime
Kansas City P&L, Hawthorne Unit 3	R	100	33	0.6-3.0	12	45	Limestone
Kansas City P&L, LaCynge Unit 1	N	820	51	5.2	8	59	Limestone
Montana Power, Colstrip Unit 1	N	335	78	0.8	12	90	Lime/Fly Ash
Montana Power, Colstrip Unit 2	N	335	78	0.8	12	90	Lime/Fly Ash
Nevada Power, Reid Gardner Unit 1	R	112	50	0.54	20	70	Sodium Carbonate
Nevada Power, Reid Gardner Unit 2	R	112	50	0.54	20	70	Sodium Carbonate
Nevada Power, Reid Gardner Unit 3	N	112	50	0.5-0.6	20	70	Sodium Carbonate
Arizona Public Service, Four Corners Units	R	160	46	--	9	54	--
Arizona Public Service, Cholla Unit 1	R	60	127	0.6	12	139	Limestone
Kentucky Utilities, Green River Units 1&2	R	60	66	3.6	12	78	Lime
Northern State Utilities, Sherburne Unit 1	N	710	73	0.8	13	86	Limestone
Pennsylvania Power, Bruce Mansfield Unit 1	N	825	145	3.8	14	159	Lime
Commonwealth Edison, Will County Unit 1	R	167	110	2.2	13	123	Limestone
Detroit Edison, St. Clair Unit 6	R	158	84	0.5-3.0	14	98	Limestone
Louisville G&E, Paddy's Run Unit 6	R	70	53	3.7	12	65	Lime
Philadelphia Electric, Eddystone Unit 1	R	103	137	2.5	27	164	Magnesium

(a) Federal Power Commission July 1977b.

(b) In 1977 dollars.

the sulfur content of the coal, regional labor and equipment cost differentials, power plant size, new versus retrofit units, and the scope of the project undertaken. Generally, FGD capital costs for plants using Western coal are \$50 to \$75/kW. The FGD capital costs for plants using higher sulfur Eastern coal are about double this amount, ranging from \$100 to \$150/kW.

Unit capital and operating costs of FGD systems are affected by power plant size and the coal's sulfur content. Unit costs have been shown to decrease as plant size increases. The extent of these scale economies are not well known. Unit costs also decrease as sulfur content decreases. Although unit costs were shown to decrease for all FGD methods, the rate at which they decrease varies significantly. For example, operating costs for the catalytic oxidation process are only minimally affected by sulfur content, whereas operating costs for sodium scrubbing are cut in half when going from 5 to 1% sulfur coal (McGlamery et al. 1975).

Operating costs for wet lime and limestone slurry systems have declined, and reliability has increased as a result of a better understanding of scrubber chemistry. For example, the average operating cost of the limestone FGD system on LaCynge Unit #1 had dropped from 1.467 mills/kWh in 1974 to 1.102 mills/kWh in 1976 and was expected to drop again in 1977. Kansas City Power and Light Co., operator of the LaCynge Station, estimates that as much as \$100,000 per month can be saved by effective pH control of the scrubber slurry (Papamarcos 1977).

SO₂ System Selection

The selection of an FGD system for a specific location must take into consideration several parameters including cost, water availability, energy use, etc. Due to limited water resources, a lime or limestone slurry system is a likely choice for a power plant in the Wyoming/Montana area. Relatively low energy requirements, low costs, and advanced technology are other reasons that support this selection. Because Wyoming coal typically contains a high alkaline ash, the fly ash is expected to supplement alkali slurry feed requirements and, in turn, reduce requirements for lime or limestone. The

reduction in lime or limestone requirements will vary with the type of coal used. If water resources are very limited, a dry scrubbing system would be necessary.

Selection of a FGD system for a Midwestern power plant should not be restricted by water resource availability. However, because of low energy requirements, low cost and advanced technology, a Midwestern power plant burning Western coal most likely will also use some form of lime or limestone slurry scrubbing with some fly ash.

Air pollution control regulations for electric power plants will have several impacts in future years. Current NSPS will require SO₂ scrubbing and high levels of particulate removal in all coal-fired plants, regardless of location or grade of coal used. Individual plants will be regulated by the implementation plan of their state. Air-quality standards and monitoring requirements will most likely vary from state to state. Third, the PSD classifications may severely limit siting and design options for particular air-quality control regions. Direct costs of air pollution control equipment, which now accounts for about 10% of total plant capital cost, is expected to increase as more stringent air-quality regulations take effect. Scrubbing to 97% removal is estimated to cause a 50% increase in the capital costs of scrubbers. System reliability may decrease due to the effects of the additional control equipment, although improvements in the reliability of air pollution control equipment can be expected as experience accrues with this technology. Finally, plant conversion efficiency may decrease due to power requirements of control equipment, although again, continual development of the technology may provide systems drawing less power.

5.1.5 Condenser Cooling Systems

Fossil-fired steam-electric plants reject about 50% of the input heat potential of the fuel as waste steam. The condenser must remove most of the heat in the waste steam to maintain an adequate low-pressure environment for turbine discharge. Currently, six major methods can provide cooling for condenser discharge:

- once-through cooling
- wet cooling towers (mechanical and natural draft)
- mechanical draft dry towers
- mechanical draft wet/dry towers
- artificial lakes
- spray canals.

The following discussion of cooling systems is intended to describe alternative systems that could be used on coal-fired plants located in the West and Midwest. Cost and technical characteristics are identified for each technology so that a cooling system that would be appropriate for each location can be selected.

Once-Through Cooling

The Federal Water Pollution Control Act (FWPCA) Amendments of 1972 have severely limited the use of once-through cooling (the simplest and generally the least expensive cooling system) to a few locations on the coastlines and to some large lakes. Although the EPA has recently expanded its position on once-through cooling for new power plants to allow exceptions to the FWPCA on a case-by-case basis, use of this type of cooling is still very restricted. As a result, cooling towers and cooling ponds have been the principal form of cooling for new and recent power plants.

Wet Cooling Towers

Wet towers use evaporative cooling in which the cooling water comes in direct contact with air. Seventy-five percent of the total heat removed from the cooling water is removed by evaporation, with most of the remainder removed by convection. Of the cooling systems planned for new steam generating units, 45% are mechanical draft wet design (Figure 5.9), and 33% are natural draft wet design (Figure 5.10) (Friedlander 1978).

Wet towers are widely used due to minimal land requirements and relatively low water consumption and capital costs. Most wet towers in the West are mechanical draft due to meteorological limitations on natural draft

FIGURE 5.9. Mechanical Draft Wet Towers

FIGURE 5.10. Natural Draft Wet Towers

towers. Mechanical towers have lower capital costs but consume slightly more water than natural draft towers. Both types have similar land requirements.

Dry Cooling Towers

Dry cooling towers (Figure 5.11) consume negligible amounts of water compared to wet cooling towers and have therefore become an alternative to wet

FIGURE 5.11. Mechanical Draft Dry Tower.
(Oleson and Boyce 1972)

cooling in arid sections of the U.S. No water/air contact occurs in dry towers, so heat must be dissipated to surrounding air via convection. These towers use four times as much energy as wet towers and cost three times as much to construct. Another problem is decreased efficiency during periods of high ambient temperature. Ultimately, dry towers may be the main cooling method used in arid regions, but it is not expected to be a viable cooling option through 1985.

Wet/Dry Cooling Towers

The wet/dry cooling tower combines the higher heat transfer of evaporative cooling with the low water consumption of dry cooling. Part of the heat is transferred by convection (dry section) and the remainder via evaporation (wet section). Although wet/dry towers have higher capital costs than wet towers, water consumption is reduced. An estimated 50% reduction in annual water consumption (of an all-wet tower) can be achieved with less than 25% dry cooling (Larinoff 1978). The operation of wet/dry systems is flexible. For example, during periods of high ambient temperature, more evaporative cooling can be used to maintain plant efficiency.

Dry and wet/dry towers are not expected to be widely used in the near future due to restrictive capital and penalty costs. Five percent of new generating units plan to use wet/dry towers (Friedlander 1978). The areas that are most likely to use some form of wet/dry cooling are the arid regions in the Southwest and certain Western minemouth facilities where the additional cost of wet/dry cooling is offset by savings in coal transportation costs.

Artificial Lakes

In areas where land is inexpensive and the terrain is suitable, artificial lakes (cooling ponds) (Figure 5.12) are a viable alternative to cooling towers. The cooling capability of artificial lakes is based on radiation and evaporative heat transfer. Artificial lakes use half the energy of wet towers and can have low total costs. The main problem with artificial lakes is the large area of land required. A rule of thumb is 1.2 acre/MW for fossil plants and 2 acre/MW for nuclear plants (U.S. EPA 1969).

FIGURE 5.12. Artificial Cooling Lake

Capital costs for artificial lakes are highly variable due to widely different land and site preparation costs. Even in regions where land is inexpensive, excavation and site preparation costs can offset the land cost advantage. Evaluating benefits of an artificial lake without a specific

location in mind is difficult. Generally, artificial lakes are not feasible in water-deficient areas because of high evaporative losses. Where land is suitable and inexpensive, artificial lakes must be compared to other cooling options based on relative costs and environmental impacts.

Spray Canals

Spray canals (Figure 5.13) use evaporation as the primary means of dissipating waste heat. The spraying action increases the air-water surface contact area and may reduce land requirements by 95% compared to artificial lakes. The total cost for a spray canal is comparable with wet towers as is water consumption. Spray canals are mainly used in the southern U.S.

FIGURE 5.13. Spray Canal Cooling (Elgawhary 1975)

Cooling System Selection

Two factors important in choosing a cooling system for a particular power plant are the physical characteristics of the site and the costs of the cooling options.

Physical Constraints. Selecting a cooling system for a particular power plant depends on many topographical, geographical, and climatic conditions. Natural draft wet towers, for instance, do not perform well in regions of low humidity, and their use is therefore limited in the West. Artificial lakes require large quantities of land and cannot compete with other cooling options

in areas where land is expensive. Table 5.7 lists the advantages and disadvantages of each system. Each of the major cooling options is affected by specific meteorological parameters. While some factors, such as relative humidity, affect all cooling methods, other factors affect only a few. Table 5.8 lists the major design considerations for each type of cooling.

The first criterion for selecting a cooling system is the availability of water and land in the area under consideration. In areas where water and land are scarce, wet towers or spray canals would be selected over artificial lakes or ponds. Table 5.9 lists the consumptive water and required land for each cooling option. If wet towers or spray canals (which have similar water consumption) are incompatible with the available water supply, then some combination of wet and dry cooling must be considered. The appropriate wet/dry configuration depends on the area's specific climate and water supply. From a cost standpoint, a utility will try to use the highest percentage of wet cooling possible, assuming water costs are low.

Cooling System Costs. The costs of major cooling options for various locations are compared in Table 5.9. The total evaluated cost is the sum of the capital cost and the penalty cost. The penalty cost component includes the following:

- maintenance cost
- additional generating equipment to compensate for energy consumed by cooling system machinery
- additional fuel to compensate for energy consumed by cooling system machinery
- generating capability losses due to decreased plant efficiency at peak ambient temperatures.

Therefore, the penalty cost provides a way to compare total system costs of cooling that would differ from an analysis of only capital and operating costs. Separate operating and maintenance (O&M) costs are not identified, although they are included in the computation of total O&M costs (Section 5.3.2).

TABLE 5.7. Cooling System Comparison

<u>System</u>	<u>Advantages</u>	<u>Disadvantages</u>
Mechanical Draft Cooling Towers	<ol style="list-style-type: none"> 1. Control over air supply 2. Control of cold water temperature 3. Generally low pumping head 4. Unaffected by relative humidity 5. More packing per unit volume of tower 6. Lower capital costs than natural draft towers 7. Nominal land requirements 	<ol style="list-style-type: none"> 1. Subject to mechanical failure 2. Subject to recirculation of humid exhaust air 3. Operation and maintenance costs are generally higher than natural draft towers 4. Possible icing and fogging 5. Blowdown disposal 6. Possible mixing with stack gases in fossil plants
Natural Draft Cooling Towers	<ol style="list-style-type: none"> 1. No mechanical or electrical components 2. Maintenance costs are lower than mechanical draft towers 3. Excellent availability 4. Nominal land requirements 	<ol style="list-style-type: none"> 1. Humidity must be high for good operation 2. Exact control of outlet water temperature is difficult. 3. Higher capital costs than mechanical towers 4. Can be aesthetically undesirable 5. Blowdown disposal 6. Possible mixing with stack gases in fossil plants
Artificial Lake	<ol style="list-style-type: none"> 1. Reasonable construction costs where soil conditions and topography permit 2. Serves as a settling basin for suspended solids 3. Can possibly operate for extended periods without makeup water 4. Can double as a recreational facility 	<ol style="list-style-type: none"> 1. Requires large quantities of land 2. Requires soil of low permeability 3. Possible fogging and icing 4. Concentrate dissolved solids 5. Large consumptive use of water
Spray Canals	<ol style="list-style-type: none"> 1. Reduced land area compared to lakes 2. Relatively simple and economic compared to cooling lakes 	<ol style="list-style-type: none"> 1. Some water loss due to drift 2. Performance is highly dependent on wind speed
Dry Cooling	<ol style="list-style-type: none"> 1. Avoid fogging, mist and icing 2. Lowest consumptive use of water for all systems 	<ol style="list-style-type: none"> 1. Very high capital cost 2. High maintenance cost 3. Larger volumes of air required to circulate 4. Decreased plant output at high dry bulb temperature 5. Larger land requirements than wet towers

TABLE 5.8. Major Design Considerations^(a)

<u>Cooling System</u>	<u>Wet Bulb Temperature</u>	<u>Dry Bulb Temperature</u>	<u>Relative Humidity</u>	<u>Air Density</u>	<u>Wind Speed and Direction</u>	<u>Cloud Cover</u>	<u>Latitude of Location</u>	<u>Mixing Coefficient</u>	<u>Surface Area</u>	<u>Heat Load</u>
Once-Through	X	X	X		X	X	X	X	X	X
Cooling Lakes	X	X	X		X	X	X	X	X	X
Spray Ponds	X	X	X	X	X	X	X		X	X
Natural Draft										
Wet Towers	X	X	X	X					X	X
Mechanical Draft										
Wet Towers	X		X		X				X	X
Dry Towers		X	X	X					X	X
Wet/Dry Towers	X	X	X	X	X				X	X

(a) Oleson and Boyce 1972.

TABLE 5.9. Comparison of Major Cooling Systems^(a)

Cooling System	State	Capital Cost ^(b) (\$/KW)	Penalty Cost ^(b) (\$/KW)	Total Evaluated Cost ^(b) (\$/KW)	Annual Water Use (Gal/kWh)	Land Requirements ^(c) (Acres)	Energy Penalty (Btu/kWh)
Mechanical Draft Wet Towers	WY	29.9	21.2	51.1			
	MT	31.3	21.9	53.2			
	OH	34.0	24.6	58.6	0.43	10	145
Natural Draft Wet Towers	CO	33.5	22.0	55.5	0.38	10	120
Spray Canals	MA	31.7	26.7	58.4	0.40	40	150
Artificial Lakes	MA Range	50.8 29-92	31.2 NA	82.0 60-123	0.5 (1 acre) 0.68 (2 acre)	1200	70
10% Wet/90% Dry Towers	WY	52.3	46.7	99.0			
	MT	56.9	48.3	105.2	0.02	14	NA
40% Wet/60% Dry Towers	WY	69.7	51.9	121.6			
	MT	77.3	61.2	138.5	Negligible	15	NA
Mechanical Draft Dry Towers	WY	116.5	70.7	187.2			
	MT	134.8	76.9	211.7	0	15	575

(a) Cost information based on Hu (1978). All other information from Cirillo (1977).

(b) Cost estimates escalated to 1981 dollars using the Handy-Whitman Index of Public Utility Construction Costs.

(c) Assumes 1000 MW plant.

The total evaluated costs for mechanical wet towers, natural wet towers and spray canals are similar. Regional cost differentials alone can upset the economic advantage of any of these three systems. In this case, cooling selection would probably be based on physical characteristics rather than on costs. Cooling pond costs vary widely depending on terrain and land costs. In some situations, cooling ponds may be economically competitive with wet towers and spray canals. Dry and wet/dry towers are significantly more costly than other systems. However, dry and wet/dry systems may be the only alternative for water-deficient areas.

Regional Recommendations

Most areas in Wyoming and Montana are semiarid. Water for energy development is relatively scarce due to large agricultural uses of existing water supplies. This, coupled with the desire of many utilities to locate power plants at the minemouth, further limits water supply options.

Mechanical draft wet towers and spray canals appear to be the cooling options that are most suited for the Wyoming/Montana region, mainly because of low costs and relatively low water consumption. High water consumption of artificial lakes and poor operation of natural draft wet towers at low humidities make these systems incompatible with this region. If water availability prohibits the use of mechanical draft wet towers and spray canals, some form of wet/dry cooling would be used.

Cooling system options for the Illinois/Missouri area are less restricted due to greater water availability and meteorological conditions favoring operation of natural draft towers. The feasibility of an artificial lake as a power plant cooling system will be determined by the cost of land and the terrain. The distance that a power plant is displaced from the load center to obtain cheap land and suitable terrain must be weighed against the additional transmission requirements to the load center. Recreational use might enhance the attractiveness of an artificial cooling lake.

Mechanical draft wet towers or spray canals more likely would be favored for a Midwest power plant. Some Midwest nuclear power plants are equipped with spray canals, and at least one study shows that spray cooling has lower

total cost than wet towers, although capital costs are slightly higher. Mechanical draft wet towers are also an effective and inexpensive cooling option for the Illinois/Missouri area, especially if land is at a premium.

The benefits of natural draft wet towers in a Midwest location must be evaluated on a case-by-case basis to determine if advantages exist over conventional mechanical draft cooling. Data from a study of cooling options for a Midwest nuclear facility suggest that the slight difference in total evaluated costs between natural and mechanical draft towers may be outweighed by environmental considerations such as fogging potential. Table 5.10 lists regional preferences of cooling alternatives.

TABLE 5.10. Regional Preferences of Cooling Alternatives

<u>Region</u>	<u>First Choice</u>	<u>Second Choice</u>
Wyoming/ Montana	Mechanical Draft Wet Towers Spray Canals	Wet/Dry Towers
Illinois/ Missouri	Mechanical Draft Wet Towers Spray Canals	Natural Draft Wet Towers Artificial Lake

5.1.6 Performance Characteristics of Coal-Fired Plants

Plant efficiency is determined by the temperature, pressure and reheat characteristics of the steam cycle and efficiencies of various plant components. Plant availability is the cumulative result of the availability of the individual components and subsystems.

Power Plant Efficiency

The efficiency of a power plant can be represented by percentage efficiency or by "heat rate." Percentage efficiency is the portion of total potential heat value of the coal that is eventually converted to electrical energy. Heat rate refers to the number of input Btu (in the coal) that are needed to produce one kilowatt-hour (1 kWh = 3,413 Btu) of electricity. In the following discussions, heat rate will generally be used as a measure of power plant efficiency.

A typical basic plant heat rate (excluding auxiliary systems) for a new power plant burning subbituminous coal is approximately 9,400 Btu/kWh (Burnham et al. 1978). This value is slightly higher than those for bituminous coal-fired power plants due to additional pulverizer requirements and higher drying temperatures for lower Btu coal. The best heat rate for all coal-fired power plants in the U.S. in 1977 was slightly less than 8,900 Btu/kWh, equivalent to 38% efficiency (U.S. DOE 1978b).

The total plant heat rate may be determined by adding incremental energy penalties for the scrubbing and cooling systems to the basic plant heat rate. Table 5.11 lists the Btu penalties for each scrubbing and cooling option. For example, a subbituminous coal-fired power plant with a pulverized coal combustion system, one reheat cycle, mechanical draft wet towers, and wet limestone scrubbing would have a heat rate of approximately 9,900 Btu/kWh, equivalent to 34.5% efficiency. Closed loop cooling systems are often sensitive to atmosphere temperature and humidity conditions, resulting in higher condenser temperatures during the warmer months, with a consequent decrease in plant efficiency. This effect is reflected, along with mechanical equipment energy requirements, in the energy penalties of Table 5.11.

Plant efficiency increases with increasing turbine inlet (throttle) steam pressure and temperature, with the number of reheat cycles, and with decreasing condenser pressure. During the evolution of steam-electric power stations, metallurgical advances have allowed a continuous increase in throttle temperature and pressure, achieving a maximum of about 5000 psi with 1200°F throttle temperature and 1050°F reheat temperature. However, the gains in efficiency provided by these operating conditions are offset by increased maintenance requirements and reduced availability (Figure 5.14). Thus, in recent years throttle conditions of 1450 to 3500 psi at 1000°F with a single 1000°F reheat have become fairly standard.

Although slight increases in steam-electric power plant efficiency may occur in the next 15 years, significant increases above 40% thermal efficiency are not expected. Instead, the recent trend of utilities to cut costs has

TABLE 5.11. Incremental Energy Penalties
for Auxiliary Systems^(a)

Cooling Systems	Btu/kWh
Mechanical Draft Wet Towers	145
Natural Draft Wet Towers	120
Spray Canals	150
Artificial Lakes	70
Mechanical Draft Dry Towers	575
<u>SO₂ Removal Systems</u>	
Limestone Slurry	360
Lime Slurry	345
Magnesium Oxide	530
Sodium Solution Scrubbing	1040
Catalytic Oxidation	11

(a) Cirillo et al. 1977.

FIGURE 5.14. Effect of Turbine Throttle Temperature on Availability
and Forced Outage Rate (Elston 1976)

been to increase plant size to achieve slight economies-of-scale. Significant increases in plant efficiency, if they occur, more likely will come from adoption of gas-fired combined-cycle plants.

Reliability, Availability, and Capacity Factor

Reliability, availability, and capacity factor are three terms that are often confused and require explanation.

Reliability of a unit is the probability that the unit or system will function for a specified period of time. The probability of a boiler functioning, for instance, may be 0.95 for any one day, and $0.21 (0.95)^{30}$ over a period of a month.

Availability is the fraction of time that a component or system is able to operate (standby or in service, full power or partial power). For a base-loaded generating system, availability is the portion of the time that the plant produces power. For any one component, availability is the portion of time that the component is operating or is on standby.

Capacity factor is the ratio of actual system output to total potential system output (operating full time at full capacity) for a given period of time. Availability includes standby time and partial and full capacity operation of generating facilities. Therefore, the capacity factor theoretically may be equal to but not greater than the availability. In reality, the capacity factor is always less than availability.

Table 5.12 shows the quantitative definitions of each of these terms. Reliability is used in failure analysis, and availability and capacity factor are used to describe a power plant's use. As the capacity factor decreases, the generation costs increase on a mills/kWh basis because capital and O&M costs are spread over shorter periods of generation time. A full examination of generation costs is presented in the power plant cost section.

Scheduled outages are planned to provide routine maintenance for specific components. These outages are scheduled at off-peak hours or seasons so that the cost of replacement power is low. Forced outages are unplanned failures

TABLE 5.12. Definition of Reliability, Availability and Capacity Factor^(a)

	Reliability (R)	Availability (A)	Capacity Factor (CF)
Parameters	Operating Time ^(b) - t Failure Rate ^(c) - λ or Mean Time Between Failure - MTBF ^(d) (MTBF = $1/\lambda$) Mean Time to Failure - MTTF ^(d)	Uptime - t_u Downtime - t_d Standby Time - t_s Time Period - Σt ($\Sigma t = t_u + t_d + t_s$)	Output ^(e) - O Capacity - C Time Period - Σt
Equation	$R = e^{-\lambda t}$ or $R = e^{-t/\text{MTBF}}$ or $R = e^{-t/\text{MTTF}}$	$A = \frac{t_u + t_s}{t_u + t_s + t_d}$ or $A = 1 - \frac{t_d}{\Sigma t}$	$CF = \frac{O}{C \Sigma t}$

Curve

(a) Hullinger, 1978.

(b) "Operating time" is a period of failure-free operation which may be expressed in units of hours, days, weeks, years, etc; or it may be expressed in other units, such as tonnage, gallons, number of operations, etc.

(c) Failure rate may be in the following units: failures per hr, or per 1000 hr; % failures per hr, or per 1000 hr; failures per ton, or per 1000 ton; etc. Units must be consistent with those for operating time.

(d) MTBF (or MTTF) is the average operating time between (or to) failure. Its units must be consistent with those for operating time.

(e) Output and capacity may be in any terms such as MWhr, HPhr, gallons, tons, etc.

in some portion of the generation process. A forced outage can typically be four to five times more costly per hour than a scheduled outage and has consequently become the subject of reliability analysis (Leung and Booth 1978). Figure 5.15 shows the operating experience for two TVA generating units, indicating availability, capacity factor, forced outage rate and scheduled outage rate for each year. Redundant systems may be provided in power plants to improve reliability. However, a point is reached where the capital invested in improving reliability is greater than the savings achieved through high capacity factors and low forced outage rates.

The capacity factor will vary throughout the plant life (Figure 5.16). Initially, it is low while start-up and operational problems are being worked out. The capacity factor increases and remains high (typically around 70%) for most of the plant life until operational problems occur more frequently and newer, more efficient units are brought onto the system. When this occurs, the capacity factor of the older plant decreases (Swift et al. 1978). The capacity factor curve in Figure 5.16 represents a levelized capacity factor of 67.7% over the 30-year plant life shown.

5.2 RESOURCE REQUIREMENTS

The energy, manpower, land, water and major material requirements of a large coal-fired power plant are reviewed below. Identifying all resources and materials used for coal-based power production is beyond the scope of this study. The resource requirements may vary considerably depending on the plant design, capacity factor, and other site-specific conditions.

5.2.1 Energy

The greatest energy requirement for coal-fired plants is coal. Other energy requirements include steam and electricity, which are produced by the plant and fuel oil for plant startup. The total annual consumption of coal depends on plant heat rate, plant size, heating value of the coal, and annual operating time of the unit. The following relationship may be used to estimate annual coal consumption on a coal-fired unit:

FIGURE 5.15. Operating Experience of Two TVA Units (Fox 1976)

FIGURE 5.16. Typical Capacity Factor Versus Plant Life

$$\text{COAL USE} = \frac{\text{HRATE} \times \text{PSIZE} \times \text{OPHRS}}{\text{HVALUE} \times 2000} \quad (5.1)$$

where:

COAL USE = annual plant coal consumption (tons)

HRATE = plant heat rate (Btu/kWh)

PSIZE = plant size (kW)

OPHRS = hours of plant operation (hr)

HVALUE = coal heat value (Btu/lb).

A typical 1000 MW coal-fired plant burning subbituminous coal (9100 Btu/lb) with a heat rate of 9900 Btu/kWh operating at 70% capacity factor (6032 hrs) would use nearly 3.3 million tons annually.

An examination of coal resources and extraction is provided in Chapter 2 of this report.

Auxiliary energy in coal-fired plants is required for many components such as pumps, fans, pulverizers, flue-gas desulfurization systems and cooling

systems. These systems use steam or electric energy produced directly from the plant. Therefore, auxiliary energy requirements can be viewed as an energy penalty that lowers the plant's conversion efficiency.

Two systems that have a significant impact on plant efficiency are cooling and FGD systems. Their incremental penalty to the plant heat rate (a measure of conversion efficiency) is important since alternative cooling and FGD technologies, having differing energy penalties, are available. Energy penalties for several cooling and FGD systems are presented in Table 5.11.

Another energy requirement for coal-fired power plants is fuel oil that is used for boiler ignition and plant heating when the plant is shut down. Fuel oil consumption will vary depending on the number of startups and plant downtime. One estimate of fuel oil needs for a 1000 MW coal-fired power plant is about 13,000 bbl/yr (Carlson et al. 1977).

5.2.2 Land

A 1000 MW coal-fired power plant typically will require about 500 acres, not including ash disposal areas and cooling systems. This figure is based on information contained in the Commercial Electric Power Cost Studies prepared by United Engineers and Constructors, Inc. (UE&C 1977a). In addition to the basic plant, areas are needed for ash and sludge disposal and cooling systems. Table 5.13 gives the land requirements for five cooling system

TABLE 5.13. Land Requirements for Cooling Systems, Typical 1000 MW Coal-Fired Plant^(a)

	<u>Acres</u>
Mechanical wet towers	10
Natural wet towers	10
Spray canal	40
Cooling pond	1200
Dry cooling towers	15
40% wet/dry towers	15
10% wet/dry towers	15

(a) Cirillo et al. 1977.

alternatives. With the exception of cooling ponds and spray canals, additional land needs for cooling systems are minor.

Table 5.14 shows the land required for ash and sludge disposal for a 1000 MW coal-fired plant operating for 35 years. These figures assume the use of Western coal under NSPS.

TABLE 5.14. Land Requirements in Acres for Ash and Sludge Disposal, 1000 MW Coal-Fired Power Plant (a,b)

<u>Ponding(c)</u>	<u>Western Coal</u>	<u>Eastern Coal</u>
Wet Sluiced Fly Ash	89.9	139.1
Wet Sluiced Bottom Ash	23.0	34.1
Scrubber Sludge		
Previous NSPS	12.1	235.0
Existing NSPS	91.9	282.0
Fly Ash and Scrubber Sludge Combined		
Previous NSPS	97.1	315.1
Existing NSPS	165.1	346.9
<u>Landfill(c)</u>	<u>Western Coal</u>	<u>Eastern Coal</u>
Dry Disposal Fly Ash	72.9	11.9
Dry Disposal of Scrubber Sludge (Dewatered to 50% Solids)		
Previous NSPS	12.1	235.0
Existing NSPS	91.9	282.0
Dry Disposal of Fly Ash and Scrubber Sludge Combined (Dewatered to 65% Solids)		
Previous NSPS	97.1	315.1
Existing NSPS	165.1	346.9

(a) Jones et al. 1978.

(b) Assumes 35-year life.

(c) Both ponds and landfills are 30 ft deep.

Total land requirements for a 1000 MW coal-fired power plant using mechanical draft cooling towers and limestone slurry scrubbing are 675 acres. If ash and sludge disposal takes place offsite, then site requirements would drop to 510 acres.

5.2.3 Water

Total water required for power production for a 1000 MW coal-fired plant using a closed-cycle cooling system is about 12 to 15 thousand acre-ft/year. This value will vary depending on FGD and cooling system selection. A list of cooling system water requirements is presented in Table 5.9. Water requirements for coal-fired power production are addressed in detail in Water Effects of the Use of Western Coal for Electrical Production (Rogers 1980).

5.2.4 Manpower

Manpower is required for construction, operation and maintenance of a coal-fired power plant. Construction of a 3000 MW power plant in Gillette, Wyoming, required 9,960 man-years, whereas operation and maintenance demands 436 people (U.S. EPA 1979).

5.2.5 Major Materials

The principal materials used in fossil-fired plants are concrete, structural steel and reinforcing steel. While amounts of these materials will vary depending on plant configuration, the FGD system and the cooling system, typical estimates can be made. Table 5.15 lists major material requirements by plant size. The table shows that a 1000 MW plant built in 1971 used less reinforcing and structural steel than a 794 MW plant in 1976. The additional materials are attributable to compliance with environmental and siting criteria in effect by 1976 (UE&C 1977a; 1977b).

5.3 POWER PLANT COSTS

In this section generic cost estimates for coal-fired power plants are derived for four locations. Site-specific, engineering cost estimates are not derived for a particular plant design. However, generic cost estimates have

TABLE 5.15. Typical Major Material Requirements for Coal-Fired Plants^(a)

Size	Concrete (yd ³)	Reinforcing Steel (lbs)	Structural Steel (lbs)
1000 MW (1/71)	76,000	7.5×10^6	32.0×10^6
794 MW ^(b) (1/76)	90,000	11.9×10^6	43.8×10^6
801 MW ^(c) (1/76)	65,900	9.0×10^6	35.3×10^6
1232 MW ^(d) (1/76)	111,200	15.2×10^6	58.4×10^6
1243 MW ^(e) (1/76)	81,600	11.8×10^6	47.0×10^6

- (a) UE&C 1977a; 1977b.
 (b) High sulfur coal, scrubber.
 (c) Low sulfur coal, no scrubber.
 (d) High sulfur coal, scrubber.
 (e) Low sulfur coal, no scrubber.

been adjusted to account for labor cost differentials among regions, specific coal burning requirements, state tax differences, plant elevation, and likely FGD and cooling systems.

Power plant (generation) costs include three components:

- capital cost
- operating and maintenance cost
- fuel cost.

In a complete electric energy supply system, the cost of fuel transportation and power transmission would be added to generation costs to determine the total delivered cost of power. In this section each component of generation costs that can be used in computing total delivered power costs is examined.

Capital costs are a fixed one-time cost that is incurred from the construction of long-term facilities and equipment. This cost will not change throughout the life of the plant. O&M costs are comprised of both fixed and variable cost components. O&M costs will vary annually depending on the type and extent of maintenance required and effects of net escalation. However, because failures and problems are difficult to predict, a large portion of O&M costs will be treated as fixed. The remaining portion varies with station

power production. The fuel cost component is variable and is based on the capacity factor, plant heat rate and unit fuel cost.

In making cost estimates for any large project, many assumptions must be made. In this study an attempt was made to standardize assumptions based on industry practice and best available information. In most cases the assumptions are based on EPRI's Technical Assessment Guide (1982), which is often used in the electric utility industry for economic studies. When more specific or detailed information was available, EPRI's assumptions were not used.

This section includes capital, O&M and fuel cost estimates of a 1000 MW coal-fired power plant. Also included is a discussion of economies-of-scale for coal-fired plants.

5.3.1 Capital Cost

Capital costs for power plants consist of both direct and indirect components. Direct costs include plant materials, equipment, and labor used for constructing the plant structure. Indirect costs include services and financing required for construction.

Direct costs for fossil-fired plants are divided into seven accounts: land and land rights, structures and improvements, boiler plant equipment, turbine plant equipment, electric plant equipment, miscellaneous plant equipment, and main condenser heat rejection system. These accounts, a widely accepted method for categorizing power plant capital costs, were developed by the NUS Corporation (NUS 1969) and adopted by the Federal Energy Regulatory Commission (FERC) in the Code of Federal Regulations (18 CFR 101, 104, 116). The seven accounts are summed to give the direct cost subtotal (DCS). Added to this is a contingency that accounts for unforeseen costs in construction and a spare parts allowance taken as a percentage of the direct equipment cost. The sum of direct costs, contingency and spare parts gives total direct costs.

Indirect costs may be classified as either time-related or nontime-related costs. Nontime-related costs include construction facilities,

equipment and services, engineering and construction management, owner's general and administrative costs, and sales tax. Time-related costs include interest during construction (IDC) and escalation during construction (EDC). Nontime-related costs are estimated as a percentage of the total direct costs. Time-related costs are based on direct and indirect costs, construction period and cost of capital.

Indirect accounting methods are less uniform than direct accounting methods and vary significantly among cost estimates. The indirect accounting method used in this section is taken from Fusion Reactor Design Studies - Standard Accounts for Cost Estimates (Schulte, Willke and Young, 1978). These also are based on the NUS document. However, some accounts have been reorganized to account for escalation during construction (Account 95) and state sales tax (included in Account 93). Interest and escalation during construction are calculated from methods developed in A Method for Estimating Escalation and Interest During Construction (EDC and IDC), prepared by Doan Phung of the Institute for Energy Analysis (Phung 1978).

The capital costs of coal-fired plants can vary significantly with plant location, construction period, coal type, plant capacity, cooling system type and air pollution control equipment requirements. The capital cost estimates presented here are based on data contained in the Final Report and Initial Update of the Energy Economic Data Base (EEDB) Program, prepared by United Engineers and Constructors (UE&C) for the U.S. Department of Energy (UE&C 1979b). The UE&C estimates were adjusted to account for regional labor cost differentials, plant elevation, coal heating value, sodium content in the coal ash, and coal grindability from relationships developed by Ebasco Services for the Washington Public Power Supply System (Carlson et al. 1977). The cost estimates presented in this section use a current dollar analysis, which assumes a 12.5% interest rate and an 8.5% escalation rate. A constant dollar analysis, which assumes a 4% interest rate and no escalation, is also computed.

Criteria for evaluating uncertainty of capital cost estimates for energy technologies were established by EPRI (1982). Sources of uncertainty include

technical modifications, estimation errors, unforeseen price changes, and other unforeseen factors (weather conditions, regulation changes, political events, etc.). Cost estimates made for coal-fired plants are more precise than other technologies due to experience with this mature technology. Still, EPRI predicts capital cost estimates for coal-fired plants to vary ± 10 to 15%.

The total capital requirement of a 1000 MW coal-fired power plant located in Wyoming and using mechanical draft wet cooling towers and a limestone slurry scrubbing system is estimated to be approximately \$1.20 billion. The capital cost for an identical plant in Montana is approximately \$1.18 billion. A breakdown of the major cost components is listed in Table 5.16. The Montana estimate is lower due to the absence of a state sales tax in Montana and interest not paid on the sales tax. Variations in coal qualities within Wyoming and Montana can affect capital costs by \$5 to 10 million because of effects on boiler size requirements. The estimates include labor rate adjustments for Cheyenne, Wyoming, as indexed in the 1980 Berger Building Cost File (Berger 1980) and use of a subbituminous Wyoming coal as specified in Table 2.7. Other assumptions used in the cost calculations are listed in Table 5.17.

The capital cost of a 1000 MW coal-fired power plant in Illinois, using assumptions similar to the Wyoming plant, is estimated to be approximately \$1.23 billion. The capital cost of an identical plant located in Missouri is also estimated to be \$1.23 billion. The breakdown of major cost components is listed in Table 5.18. The Missouri plant would cost slightly less than the Illinois plant due to a lower state sales tax and interest paid on that tax. Other differences in capital cost between an Illinois and Missouri plant are expected to be small since St. Louis labor rates are similar to Chicago labor rates and no major differences in topography exist. Again, variations in coal qualities could affect costs of either plant by \$5 to 10 million.

The main difference in capital costs between the Illinois and Wyoming plants is due to the high labor rates for the Chicago area. However, the higher plant elevation for Wyoming, which increases boiler and scrubber costs, lowers this difference. It should be noted that the capital cost of a

TABLE 5.16. Capital Cost of a 1000 MW Coal-Fired Power Plant in Wyoming and Montana^(a)

Account	Description	10 ⁶ s
<u>Direct Costs</u>		
20	Land and Land Rights	2.0
21	Structures and Improvements	75.8
22	Boiler Plant Equipment	210.8
23	Turbine Plant Equipment	111.0
24	Electric Plant Equipment	46.2
25	Miscellaneous Plant Equipment	14.4
26	Main Condenser Heat Rejection System	18.6
2	Direct Cost Subtotal (DCS)	478.8
--	Contingency (15% DCS)	71.8
--	Spare Parts (1% Direct Equipment)	2.6
	Total Direct Costs	553.2
<u>Indirect Costs</u>		
91	Construction Facilities, Equipment and Services (12.5% DCS)	59.9
92	Engineering and Construction Management (10% DCS)	47.9
93	Owner's Cost (9% DCS)	43.1
	State Sales Tax (3% DCS)	14.4
	Total Indirect Costs	165.3
	Total Plant Costs	718.5
94	Interest During Construction (IDC) ^(c)	311.2
95	Escalation During Construction (EDC) ^(c)	129.8
	Total Plant Investment	1159.5
	Working Capital, Startup Cost, and Initial Coal Pile (WSI) ^(d)	43.0
	Total Capital Requirements	1202.5

- (a) Total plant costs are in 1981 dollars. IDC and EDC are included in total plant investment to reflect interest costs and cost increases incurred over the construction period. Using 1981 start of construction and a 5-year construction period, the total plant investment represents the total cost realized at the end of construction in 1986.
- (b) All costs are based on a Wyoming plant location. If a Montana plant location is used, the following costs would differ: state sales tax = 0; total indirect costs = 150.9; total plant costs = 704.1; IDC = 304.0; EDC = 127.2; total plant investment = 1135.3; WSI = 42.4; total capital requirement = 1177.7.
- (c) For IDC and EDC calculations we assume a 5-year construction period, 8.5% nominal escalation rate, 12.5% interest rate, and a symmetric and discrete payout schedule occurring at the beginning of each year as follows: year₁ = 5%, year₂ = 26%, year₃ = 38%, year₄ = 26%, year₅ = 5%.
- (d) Working capital and startup costs estimated at 3.5% total plant costs + 1.5 months O&M costs, escalated to 1986 dollars (at 8.5%), when these charges will occur. Initial coal pile based on 60-day storage at 100% capacity at a 1986 fuel price of \$11.67/ton.

TABLE 5.17. Assumptions Used in Power Plant Cost Calculations

Plant Includes:

- Hot Side Electrostatic Precipitator (fabric filter can be substituted at same cost)
- Mechanical Draft Wet Cooling Towers
- Limestone Slurry Scrubbing System
- Coal Handling Facilities Including 60-Day Storage Pile Area
- Generator Step-Up Transformers
- Ash and Sludge Disposal Area for Life of Plant

Cost Estimate Includes:

- Labor Rates for 1/81
 - Wyoming/Montana Plant: Cheyenne, Wyoming Rates
 - Illinois/Missouri Plant: Chicago, Illinois Rates
- Interest During Construction of 12.5%
- Escalation During Construction of 8.5%
- Contingency of 15% Total Direct Costs
- Spare Parts Allowance of 1% Direct Equipment Cost
- Sales Tax
 - Wyoming: 3% Illinois: 4%
 - Montana: 0% Missouri: 3.125%
- Owners Cost of 9% Total Direct Costs
- Working Capital of 3.5% Total Plant Cost plus 1.5 Months Operating Cost
- Initial Coal Pile, 60-Day Storage @ 100% Capacity, \$11.67/Ton

Assumptions:

- 1/81 Cost Basis
- Elevation:
 - Wyoming/Montana 5000 ft
 - Illinois/Missouri Sea Level

TABLE 5.18. Capital Cost of a 1000 MW Coal-Fired Power Plant for Illinois and Missouri^(a)

Account	Description	10 ⁶ \$
<u>Direct Costs</u>		
20	Land and Land Rights	3.7
21	Structures and Improvements	73.3
22	Boiler Plant Equipment	213.5
23	Turbine Plant Equipment	114.3
24	Electric Plant Equipment	48.9
25	Miscellaneous Plant Equipment	15.0
26	Main Condenser Heat Rejection System	19.7
2	Direct Cost Subtotal (DCS)	488.4
--	Contingency (15% DCS)	73.3
--	Spare Parts (1% Direct Equipment)	2.6
	Total Direct Costs	564.3
<u>Indirect Costs</u>		
91	Construction Facilities, Equipment and Services (12.5% DCS)	61.1
92	Engineering and Construction Management (10% DCS)	48.8
93	Owner's Cost (9% DCS)	44.0
	State Sales Tax (4% DCS)	19.5
	Total Indirect Costs	173.4
	Total Plant Costs	737.7
94	Interest During Construction (IDC) ^(c)	319.5
95	Escalation During Construction (EDC) ^(c)	133.3
	Total Plant Investment	1190.5
	Working Capital, Startup Cost, and Initial Coal Pile (WSI) ^(d)	43.8
	Total Capital Requirements	1234.3

- (a) Total plant costs are in 1981 dollars. IDC and EDC are included in total plant investment to reflect interest costs and cost increases incurred over the construction period. Using a 1981 start of construction and a 5-year construction period, the total plant investment represents the total cost realized at the end of construction in 1986.
- (b) All costs are based on a Illinois plant location. If a Missouri plant location is used, the following costs would differ: state sales tax = 15.3; total indirect costs = 169.2; total plant costs = 733.5; IDC = 317.7; EDC = 132.5; total plant investment = 1183.7; WSI = 43.6; total capital requirement = 1227.3.
- (c) For IDC and EDC calculations we assume a 5-year construction period, 8.5% nominal escalation rate, 12.5% interest rate, and a symmetric and discrete payout schedule occurring at the beginning of each year as follows: year₁ = 5%, year₂ = 26%, year₃ = 38%, year₄ = 26%, year₅ = 5%.
- (d) Working capital and startup costs estimated at 3.5% total plant costs + 1.5 months O&M costs, escalated to 1986 dollars (at 8.5%), when these charges will occur. Initial coal pile based on 60-day storage at 100% capacity at a 1986 fuel price of \$11.67/ton.

specific power plant may vary significantly from the estimates presented here. For a given location construction expenses may vary for many reasons (e.g., difficult terrain, additional rail spurs, delays in construction, etc.). The estimates presented here are intended to be representative for each region.

A limestone slurry scrubbing system was assumed for both locations due to the relatively long operating experience and low cost of this system. However, since both plants will probably use a high alkali ash coal, the ash is expected to supplement the slurry feed and thereby reduce limestone requirements. The net effect of this reduction will appear as a decrease in the scrubber's operating costs. Similarly, a mechanical draft wet cooling tower was chosen for both plants since this type of cooling provides low-cost cooling with relatively low water consumption for a wide variety of locations.

Because the proposed NSPS would require SO₂ scrubbing on all plants, the capital costs of flue-gas desulfurization systems were not broken out as a separate optional cost component. The main portion of scrubber costs was included in the boiler plant equipment account. When examining alternate scrubbing systems, adjustments should be made in the structures and improvements, in the boiler plant, and in the electric plant accounts to evaluate the total impact of the cost differences.

A large portion of the cooling system cost is included in Account 26, Main Condenser Heat Rejection System, of Tables 5.16 and 5.18. The balance of the cooling system cost, principally the main condensers, is included in Account 23, Turbine Plant Equipment. If alternate cooling systems are evaluated, appropriate adjustments can be made to reflect the impact of the difference in system cost.

One component of capital cost that is usually not included in power plant estimates is funds for working capital, startup costs, and initial coal pile. While this component is often omitted so that cost estimates may be more easily compared, it must be included in an analysis of total electric power costs. Working capital is usually computed as a portion of capital cost and as a portion of O&M cost. The working capital estimates of Tables 5.16 and 5.18 are based on 3.5% of total plant cost plus 1.5 months O&M cost.

Initial coal pile is calculated for a 60-day storage at \$11.67/ton. When combined with total power plant costs, these three estimates give the total capital investment required at each plant location.

Scale Effects of Power Generation

An important consideration in power system planning is the size of power generating units. Generally, construction of larger generating units results in lower average capital cost per unit capacity (\$/kW). Construction economies-of-scale has often been cited as an advantage of larger generating units. However, other factors such as O&M cost and system reliability may offset the capital cost advantage of larger units.

Economies-of-scale has two separate effects for coal-fired plants. First, the unit investment cost (\$/kW) of coal-fired generating stations decreases with increasing station size (MW rating). This effect is shown in the 1977 and 1979 Steam Station Cost Survey compiled by Electrical World (Friedlander 1977; 1979), presented in Figure 5.17. For both time periods, unit investment cost noticeably decreased as station size increased. However, economies-of-scale for individual units within a generating station is not evident from Figure 5.17.

The unit investment cost of coal-fired generating units (single boiler, single turbogenerator) has also been shown to decrease with increasing generator size. However, disagreement exists about the magnitude of scale effects and the size range where it is applicable. EPRI uses the following relationship for adjusting power plant capital costs in the 500 to 1000 MW range (EPRI 1982):

$$C = C_0 \left(\frac{MW_0}{MW} \right)^{0.15} \quad (5.2)$$

where

C = new plant cost (\$/kW)

C_0 = base plant cost (\$/kW)

MW_0 = base plant size (MW)

MW = new plant size (MW).

FIGURE 5.17. Unit Investment Cost as a Function of Station Size

The low coefficient (0.15 for coal compared to 0.47 for nuclear) reveals that only slight economies exist for large coal-fired plants.

Future coal-fired projects may experience even smaller economies-of-scale. One reason for this is the increased cost of financing for power projects. Because interest rates are independent of project size, financing costs become a larger portion of total plant investment costs, reducing economies-of-scale effects. In addition, design engineering, tax, insurance, administration, overhead and indirect costs are largely immune to economies-of-scale effects (Comtois 1977).

Planners have observed that scale effects in the late 1960s were not as significant as those of earlier years (Comtois 1977). Some suggest that for

coal-fired plants economies-of-scale exist only up to 800 MW and that diseconomies may occur above 1000 MW (Gilmer, Meunier and Whittle 1978).

One factor favoring small plant construction is the shorter time required to get a plant on-line. After obtaining appropriate permits, 200 MW units can go on-line in as little as 30 months (Gilmer, Meunier and Whittle 1978). This compares to 4 to 5 years at best for a 1000 MW unit. If expensive combustion turbines must be used to meet load requirements until larger units come on-line, an arrangement of five 200 MW units could prove less costly than a single 1000 MW unit.

Two factors that may encourage economies-of-scale for future coal-fired plants are the additional siting analysis required to comply with air-quality regulations and the inclusion of FGD equipment on all plants. Preconstruction air-quality monitoring and analysis could be required of all potential plant sites. The costs associated with this type of monitoring could be fixed regardless of plant size and would favor larger plant sizes.

Desulfurization equipment, which represents 10 to 15% of a power plant's capital cost, has been shown to exhibit economies-of-scale (McGlamery et al. 1975). Larger plants would have lower average capital costs (\$/kW) for FGD equipment. A detailed discussion of FGD costs is presented in Section 5.1.

Although economies-of-scale exist for power plant construction, unit O&M costs may be higher in large units. One factor that could lead to higher O&M costs is low reliability of units. From 1965 to 1974, forced outage rates, an indicator of low reliability, were highest for fossil generating units in the 600 to 1400 MW range. During forced outages, power must be obtained from other sources such as combustion turbines or by purchasing power from neighboring utilities. Both options result in high system operating costs. Forced outage rates for fossil generating units are shown in Figure 5.18.

Another effect of forced outages from large units is the large quantities of lost power. An outage in a single 1000 MW unit is more severe than an outage in one of two 500 MW units. In the latter case only half as much power must be obtained to meet load requirements.

FIGURE 5.18. Forced Outage Rates for Fossil Generating Units (FPC 1977a)

Generalizing about economies-of-scale for coal-fired plants is difficult. Each project has several factors that could escalate costs far beyond projected levels. However, scale effects for plant construction appear to exist in the 500 to 1000 MW range. Above 1000 MW, scale effects diminish and may be negligible. Several factors will affect economies-of-scale for future coal-fired plants, but their impacts are uncertain at this time.

5.3.2 Operating and Maintenance Costs

Costs incurred for operating and maintaining power plants include direct and indirect components. Direct costs include materials and labor needed for the immediate operation and maintenance of the plant, such as plant operators and maintenance staff, water treatment, and chemical and ash handling costs. Indirect costs are those associated with the overall operation of the plant, such as taxes, insurance, and administrative and general expenses.

The Washington Public Power Supply System has identified 11 categories of direct O&M costs (Carlson et al. 1977):

1. plant labor
2. operations division labor
3. training
4. travel and transportation
5. fuel oil ignition
6. environmental monitoring
7. coal and ash handling
8. operating materials and supplies
9. maintenance materials and supplies
10. consulting, services and fees
11. shutdown power.

In addition to the above categories, scrubber O&M costs were cited as an optional component that can be distributed among the 11 categories.

Indirect O&M categories are as follows:

1. administrative and general expenses
2. capital additions and replacements
3. insurance
4. taxes

Indirect costs, with the exception of administrative and general expenses, are included as factors in the fixed charged rate and thus are calculated as a percentage of plant capital costs.

A brief explanation of the O&M cost categories, including their approximate portion of total O&M costs, is given in Table 5.19.

United Engineers and Constructors have developed a methodology for estimating O&M costs based on a series of generic relationships. Major parameters include type of plant (coal or nuclear), plant size, plant output, type of cooling system and SO₂ removal equipment.

Costs are grouped into six general categories for estimating O&M charges:

- plant staff
- fixed maintenance materials

TABLE 5.19. Description of O&M Cost Components^(a)

<u>Direct Costs</u>		<u>Percent of Total^(b)</u>
Plant Labor	Includes the staff needed to operate and maintain the power plant.	23
Operations Division Labor	Includes the off-site annual support staff from the operations division	2
Training	Includes new hire training for plant staff.	2
Travel and Transportation	Includes business travel expenses for plant personnel and upkeep of plant vehicles.	1
Fuel Oil	Includes fuel needed for start-ups (approximately 12 per year) and plant heating when the main boiler is shut down.	2
Environmental Monitoring	Includes the cost of operating and maintaining air and water monitoring equipment.	1
Coal and Ash Handling Cost	Includes the cost of operating and maintaining equipment to move coal and dispose of ash and scrubber by-products.	4
Operating Materials and Supplies	Includes consumable supplies used in the operation of the plant. A major component is water treatment chemicals.	19
Maintenance Materials and Supplies	Includes all equipment and supplies used by the maintenance staff.	18
Consulting, Services and Fees	Includes costs for periodic consulting and services associated with the operation of the plant.	7
Shutdown Power	Includes necessary power needs of the plant during outages. This does not include replacement power.	3
<u>Indirect Costs</u>		
Administrative and General Expenses	Includes headquarter expenses associated with the project.	17
Capital Additions and Replacement	Includes replacement of worn equipment and new additions.	NA ^(c)
Insurance	Includes property insurance based on the capital cost of the plant.	NA
Taxes	Includes taxes exclusive of original sales tax. Private utilities are subject to property taxes based on the capital cost of the plant. Public utilities may be taxed on power generated (privilege tax) in lieu of a property tax depending on state laws.	NA

(a) Carlson 1977.

(b) Percentages do not add to 100 due to rounding.

(c) NA = not applicable. These components are calculated as factors included in the fixed charge rate.

- variable maintenance materials
- fixed supplies and expenses
- variable supplies and expenses
- administrative and general expenses.

While the UE&C methodology appears to be a useful way of determining engineering cost estimates for operation and maintenance, it requires specification of nearly 30 variables. This method would be useful for more detailed cost analysis if detailed plant information were specified. Although a simplified approach has been used for this study, the UE&C methodology is reproduced in Appendix B for more detailed analysis.

The method of calculating O&M costs in this study is based on three types of costs: fixed, variable and consumable. Fixed costs are virtually independent of the number of hours of plant operation. Variable and consumable costs are proportional to the energy production of the plant. Consumable costs include water, chemicals, catalysts, waste disposal and other supplies that are used up in direct proportion to the operating hours of the plant.

Estimates of fixed, variable and consumable costs are derived from the EPRI Technical Assessment Guide (1982) and may be computed as follows.

Total Annual Operating and Maintenance Cost:

$$TOM = FOM + VOM + COM \quad (5.3)$$

where

TOM = total annual O&M costs (\$/yr)

FOM = fixed O&M costs (\$/yr)

VOM = variable O&M costs (\$/yr)

COM = consumable O&M costs (\$/yr)

Fixed Operating and Maintenance Costs:

$$FOM = FIXC \times PSIZE \quad (5.4)$$

where

FIXC = unit fixed O&M cost per year (\$/kW-yr)

PSIZE = plant size (kW)

Variable Operating and Maintenance Cost:

$$VOM = \frac{VARC \times PSIZE \times CAPF \times 8760 \text{ (hrs/yr)}}{1000 \text{ (mills/dollar)}} \quad (5.5)$$

where

VARC = unit variable O&M cost per year (mills/kWh)

CAPF = annual capacity factor of the plant (fraction)

Consumable Operating and Maintenance Cost:

$$COM = \frac{CONC \times PSIZE \times CAPF \times 8760 \text{ (hrs/yr)}}{1000 \text{ (mills/dollar)}} \quad (5.6)$$

where

CONC = unit consumable O&M cost per year (mills/kWh)

For this study, the following EPRI (1982) assumptions are used for O&M costs:

fixed (FIXC) = \$10.4/kW-yr

variable (VARC) = 0.9 mills/kWh

consumable (CONC) = 1.0 mills/kWh

All costs are in 1981 dollars and would be subject to 8.5% nominal escalation per year.

Based on a 1000 MW plant size with an annual capacity factor of 70%, the total annual O&M cost would be \$22.1 million in 1981 dollars. At a 70% capacity factor, this translates to 3.1 mills/kWh.

5.3.3 Fuel Costs

Expenditures for fuel represent a third component of power plant costs. Although fuel is a variable expense, it is separated from O&M costs since fuel is subject to escalation not related to other power production costs. While O&M costs have remained fairly constant over time, fuel costs have increased significantly (Figure 5.19).

FIGURE 5.19. O&M and Fuel Costs Over Time

Fuel costs for Western coal specified in this study are based on price projections developed by EPRI (1982). Fuel price projections for coal are published for eight geographical regions of the U.S., each with coal of varying sulfur contents. In all, price projections are made for 43 types of coal. Price projections for low sulfur subbituminous coal from the western Northern Great Plains is used as the basis for estimating fuel costs in this study. These projections are given in Table 2.7 in Chapter 2.

The total annual fuel cost may be computed in two ways. If fuel costs are expressed as dollars per million Btu ($\$/10^6$ Btu), the following relationship would apply:

$$\text{Fuel Cost} = \frac{\text{COALP} \times \text{HRATE} \times \text{PSIZE} \times \text{CAPF} \times 8760 \text{ (hrs/yr)}}{1 \times 10^6 \text{ (Btu)}} \quad (5.7)$$

where

Fuel Cost = annual fuel cost (\$/yr)

COALP = unit coal price (\$/10⁶ Btu)

PSIZE = plant size (kW)

HRATE = heat rate of plant (Btu/kWh)

CAPF = plant capacity factor (fraction)

Alternatively, Equation 5.1 (in Section 5.2) can be used to compute annual coal requirements, which, when multiplied by the unit coal price (\$/ton), will yield the same result as given above.

For a 1000 MW plant operating at a 70% capacity factor using a 9100 Btu/lb coal priced at \$11.47/ton (\$0.63/10⁶ Btu) at a plant heat rate of 9900 Btu/kWh, the total annual fuel cost would be \$38.2 million in 1981 dollars.

5.4 ENVIRONMENTAL EFFECTS

The principal environmental effects of coal-fired electric generation discussed in this section are atmospheric emissions, wastewater discharge and effluents, solid waste generation, and accident rates. Relevant regulations are briefly reviewed where appropriate. In addition to the environmental effects listed above, noise and visual impacts of a power plant are discussed qualitatively. Although no federal standards exist for noise (other than OSHA standards for occupational noise) and visual effects from power plants, state and local ordinances and regulations often control conditions such as noise, vibration, glare and landscaping. Other secondary effects of power plant construction and operation including acid rain, impacts on biotic systems, cultural impacts, health effects, and socioeconomic impacts are beyond the scope of this report.

5.4.1 Atmospheric Emissions

Most air-quality regulations originate from some portion of the Clean Air Act. Included in the act are the following:

- National Ambient Air-Quality Standards (NAAQS)
- State Implementation Plan (SIP) of the NAAQS

- New Source Performance Standards (NSPS)
- Prevention of Significant Deterioration Standards (PSD).

A more detailed discussion of these air-quality regulations is presented in Appendix A and in the air pollution control subsection of Section 5.1.

Of the above standards, the NSPS and the PSD regulations limit power plant emissions the most. Some state implementation plans provide standards less stringent than the NSPS; however, the federal NSPS preempt less stringent state standards. The Wyoming and Montana standards for SO_2 are more stringent than the NSPS requirements (Table 5.20). The PSD standards may be more stringent than the NSPS; however, PSD standards are based on state classification of regions and its impact will remain uncertain until the state implementation plans are issued. The U.S. EPA established the PSD regulations to insure that areas that have pollutant concentrations below the NAAQS would not suffer further significant deterioration of their air quality. The PSD regulations basically establish a program to control degradation of the ambient air quality by limiting emissions in areas known as air-quality control regions. These regulations have a significant effect in controlling development in certain areas of the country.

TABLE 5.20. New Source Performance Standards and SO_2 Standards for Wyoming and Montana

	<u>Particulates</u>	<u>SO_2</u>	<u>NO_x</u>
NSPS ^(a)	0.03 lb/10 ⁶ Btu (99% Reduction)	0.5 lb/10 ⁶ Btu ^(b) (70% Reduction)	0.5 lb/10 ⁶ Btu ^(c) (65% Reduction)
Wyoming SIP	Less stringent than NSPS	0.2 lb/10 ⁶ Btu	Less stringent than NSPS
Montana SIP	Less stringent than NSPS	1.0 lb/10 ⁶ Btu	Less stringent than NSPS

(a) Environment Reporter 1978a, and Allen and Kaslow 1979 (see Table 5.1).

(b) Assumes 0.8% sulfur and 9100 Btu/lb coal.

(c) NO_x standard for subbituminous coal.

Power Plant Emissions

A comparison of typical uncontrolled and controlled emissions from a coal-fired power plant is given in Table 5.21. The emission levels given in Table 5.21 assume combustion of a typical Wyoming subbituminous coal with a heat value of 9100 Btu/lb, 10% ash content and 0.8% sulfur content. The annual pollutant levels of Table 5.21 were based on a 1000 MW power plant operating at 67.7% capacity and having a 9900 Btu/kWh heat rate. Reductions in potential emission levels for a plant meeting current NSPS occur for three pollutants: particulates, SO₂ and NO_x. Regulations for SO₂ require a reduction of 70% to comply with the NSPS. Reductions in potential emission levels for particulates and NO_x under NSPS are 99.7% and 32%, respectively, for 9100 Btu/lb coal with 10% ash and 0.8% sulfur. Trace elements, which are not controlled at this time, are listed in Table 5.22.

Besides combustion products, coal-fired power plants emit fugitive dusts that arise from construction, vehicle operation, and coal, limestone and solid waste handling and storage. These emission rates are highly variable depending on the amount of material handled, type of handling facility and storage, the quantity and location of the stored material and weather conditions. Fugitive dust emission factors given in Table 5.23 are rough estimates.

5.4.2 Water Impacts

The Federal Water Pollution Control Act (FWPCA) Amendments of 1972 establish the major guidelines for water-quality standards. The act was later amended by the Clean Water Act of 1977.

Three important sections of the FWPCA establish effluent guidelines for chemical and thermal wastes for steam-electric generating plants:

- Thermal Discharge Limitations
- New Source Performance Standards (NSPS)
- National Pollution Discharge Elimination System (NPDES).

Specific effluent limitations have been issued for the steam-electric power generating point source category in the Code of Federal Regulations

TABLE 5.21. Comparison of Uncontrolled and Controlled Emissions from a Coal-Fired Power Plant^(a)

	Uncontrolled		Controlled to Current NSPS		% Reduction
	lb/10 ⁶ Btu ^(b)	tons/yr ^(b,c)	lb/10 ⁶ Btu ^(b)	tons/yr ^(b,c)	
Particulates	8.79	252,827	0.03	862	99.7
SO ₂	1.67	48,034	0.5	14,382	70
NO _x	0.74	21,285	0.5	14,382	32
Hydrocarbons	0.012	345	0.012	345	0
CO	0.041	1,179	0.041	1,179	0

(a) Based on data from Cirillo et al. 1977 and Hittman and Associates 1974.

(b) Assumes 9100 Btu/lb coal, 10% ash, 0.8% sulfur.

(c) Assumes 1000 MW power plant, 67.7% capacity factor, 9,900 Btu/kWh heat rate.

TABLE 5.22. Annual Trace Element Emissions from a 1000 MW
Conventional Coal-Fired Power Plant^(a)

<u>Pollutant</u>	<u>Emission (tons/yr)^(b,c)</u>
As	14.2
B	32.7
Ba	2.17
Be	0.31
Cd	1.97
Cr	20.53
Cu	7.5
F	196.0
Fe	1025.0
Hg	0.63
Mn	51.4
Ni	7.5
Pb	36.5
Se	5.9
V	18.6
Zn	118.0

-
- (a) Argonne National Laboratory.
1977. Impacts and Constraints.
Vol. II. (Draft) of An Integrated
Assessment of Increased Coal Use in
the Midwest. ANL/AA-11, Argonne
National Laboratory, Argonne,
Illinois.
- (b) Assumes combustion of an Eastern
province coal and a plant heat rate
of 8970 Btu/ kWh.
- (c) Plant operates at 100% capacity and
conforms to previous New Source
Performance Standards.

TABLE 5.23. Fugitive Dust Emission Factors

<u>Activity</u>	<u>Emission Factor</u>
Construction	1.2 tons/acre-month ^(a)
Coal Handling	0.0068 lb/ton ^(b)
Coal Processing	0.002 lb/ton ^(b)
Coal Storage	1.23 lb/acre ^(c)
Limestone Transport, Handling and Processing	0.006 lb/ton ^(b)
Limestone Storage	0.33 lb/ton ^(a)

(a) Factors based on Cowherd et al. 1974.

(b) Factors based on Blackwood and Peters 1976.

(c) Factor based on an average wind speed of
4.2 in/sec. (PEDCO Environmental Inc. 1978).

(40 CFR 423). EPA's interpretation of Best Practicable Control Technology (BPCT), Best Available Technology Economically Achievable (BATEA) and NSPS are specified in this section of the CFR. The most stringent of these standards that would apply to new generating sources over 25 MW are the NSPS. The NSPS for effluent discharge are given in Table 5.24.

Polluting sources must receive permits to discharge into navigable waters. Under the NPDES, new power plants that comply with the NSPS may obtain NPDES permits. Other power plants may be subject to BPCT and BATEA. Besides the direct discharge of wastewater from the power plant, water-quality concerns also arise from coal pile run off and ash and scrubber sludge leachates and effluents. The NPDES regulations restrict the amount and quality of effluents that can be discharged from coal storage piles. Treatment of coal pile runoff will be necessary. Control of leachates and effluents from disposed ash and scrubber sludge is required under the Resource Conservation and Recovery Act (RCRA) regulations for solid waste disposal currently being developed by EPA.

Table 5.25 identifies pollutants potentially found in power plant waste streams. Further discussion of these sources is presented by Rogers (1980).

TABLE 5.24. New Source Performance Standards for Steam-Electric Power Generating Point Source Category^(a)

Effluent Characteristic/ Effluent	pH	Poly-Chlorinated Biphenol Com- pounds Allowed	Allowable Discharge is Flow Multiplied by the Following Concentrations in mg/l										Corrosion ^(c) Inhibitor
			Total Suspended Solids		Oil and Grease		Copper, Total		Iron, Total		Free Available Chlorine ^(b)		
			Max.	Avg.	Max.	Avg.	Max.	Avg.	Max.	Avg.	Max. Ever	Daily Avg.	
Low Volume Wastes	6.0-9.0	None	100	30	20	15	NA	NA	NA	NA	NA	NA	NA
Bottom Ash Transport	6.0-9.0	None	100 ^(b)	30 ^(d)	20 ^(d)	15 ^(d)	NA	NA	NA	NA	NA	NA	NA
Fly Ash Transport	6.0-9.0	None	None	None	None	None	NA	NA	NA	NA	NA	NA	NA
Metal Cleaning Wastes	6.0-9.0	None	100	30	20	15	1.0	1.0	1.0	1.0	NA	NA	NA
Boiler Blowdown	6.0-9.0	None	100	30	20	15	1.0	1.0	1.0	1.0	NA	NA	NA
Cooling Tower Blowdown	6.0-9.0	None	NA	NA	NA	NA	NA	NA	NA	NA	0.5	0.2	NDA
Area Runoff	6.0-9.0	NA	Not to exceed 50		NA	NA	NA	NA	NA	NA	NA	NA	NA

Key: Max. = Maximum for one day
Avg. = Average of daily values for 30 consecutive days
NA = Not applicable
NDA = No detectable amount

(a) 40 CFR 423.

(b) Neither free available chlorine nor total residual chlorine may be discharged on the average from any unit for more than 2 hr in any one day, and not more than one unit in any plant may discharge free available chlorine or total residual chlorine at any one time, the latter provision being subject to waiver in special circumstances.

(c) Materials added for corrosion inhibition including, but not limited to, zinc, chromium and phosphorous.

(d) After multiplying the flow of these numbers, one must divide the product by 20.

TABLE 5.25. Identified Pollutants from Waste Streams^(a)

Parameter	Condenser Cooling System		Water Treatment			Chemical Cleaning							Air Pollution Devices		Sanitary Wastes	Low Rad Wastes
	Once Through	Recirculating	Clarification Wastes	Ion Exchange Wastes	Evaporator	Boiler Blowdown	Boiler Tubes	Air Pre-heater	Boiler Fireside	Ash Pond Overflow	Coal Pile Drainage	Floor Drains	SO ₂ Removal			
Alkalinity	X	X	X	X	X	X	X	X	X	X			X		X	
BOD		X	X	X	X	X	X	X		X		X	X		X	
COD		X	X	X	X	X	X	X	X	X		X	X		X	
TS	X	X	X	X	X	X	X	X	X	X	X	X	X		X	
TDS	X	X	X	X	X	X	X	X	X	X	X	X	X		X	
TSS		X	X	X	X	X	X	X	X	X	X	X	X		X	
Ammonia		X	X	X	X	X	X	X	X	X	X				X	
Nitrate		X	X	X	X	X	X	X	X	X	X				X	
Phosphorous		X	X	X	X	X	X			X	X		X		X	
Turbidity		X	X		X	X	X	X	X	X	X	X	X		X	
Fecal Coliform																
Acidity							X	X	X	X	X	X	X			
Hardness, Total		X	X	X	X	X	X	X	X	X	X	X	X			
Sulfate		X	X	X	X	X	X	X	X	X	X	X	X			
Sulfite								X	X	X		X	X			
Bromide							X								X	
Chloride		X	X		X	X	X	X	X	X	X					
Fluoride		X	X	X			X			X						
Aluminum		X	X		X	X	X		X	X	X		X			X
Boron																
Chromium		X	X	X	X	X	X	X	X	X	X					
Copper	X	X	X	X	X	X	X	X	X	X	X					
Iron		X	X	X	X	X	X	X	X	X	X		X			
Lead										X	X	X				
Magnesium		X	X	X	X	X	X	X	X	X	X	X	X			
Mercury			X	X		X			X	X	X					
Nickel		X	X	X	X	X	X	X	X	X	X					
Selenium							X			X	X					
Vanadium									X	X			X			
Zinc		X	X	X	X	X	X			X	X					
Oil and Grease				X			X			X		X				
Phenols		X	X		X					X	X				X	
Surfactants					X		X			X		X				
Algicides	X	X													X	
Chlorine	X	X														
Manganese		X		X	X	X	X		X	X	X		X			

NOTE: Miscellaneous streams such as laboratory sampling, stack chemical, etc., are not included since the species are accounted for in other streams.
 (a) Burnham 1978.

Table 5.26 lists the estimated levels of water pollutants from coal-fired power plants. Pollutants controlled by NSPS are within allowable limits. All other pollutants are assumed to have uncontrolled discharge.

Thermal discharges under NSPS are to be zero. The exceptions are that heat may be discharged in blowdown from recirculating cooling water systems or cooling ponds if the temperature at which the blowdown is discharged does not exceed, at any time, the lowest temperature of recirculated cooling water prior to the addition of the make-up water (40 CFR 423). However, Section 316(a) of the Clean Water Act allows relaxation of the thermal limitations if the discharger can demonstrate to the EPA that NSPS thermal effluent limitations are unnecessary to protect the indigenous population of fish and wildlife. Exemptions will be limited to very large bodies of water. Of the areas considered in this study, only a power plant using one of the Great Lakes for cooling could consider applying for an exemption.

5.4.3 Solid Waste Generation

Land requirements for disposal of solid wastes associated with operation of a coal-fired power plant were discussed in a previous section (5.2). These solid wastes include fly ash, bottom ash, scrubber sludge, and sludge from water treatment processes. Wastes produced from the water treatment process are difficult to quantify; however, in general their quantities are much smaller than the other wastes.

The quantity of ash and scrubber sludge generated highly depends on the coal type and the method of air pollution control employed. The quantities of bottom ash, fly ash and scrubber sludge were estimated for Western coal both with and without lime scrubbers (U.S. DOE 1980). These values are presented in Table 5.27.

5.4.4 Land Impacts

The removal of sulfur from the stack gases transforms an air pollution problem into a solid waste problem. Although FGD methods that produce a

TABLE 5.26. Estimated Pollutant Levels from Coal-Fired Power Plants^(a)

Pollutant	lb/day/MW	lb/10 ³ tons Coal Consumed
TSS	0.099 ^(b)	10
Phenols	--	--
Oil and Grease	0.0491 ^(b)	4.9
Ammonia-N	2.39×10^{-3} ^(c)	0.24
Nitrate-N	2.0×10^{-3} ^(c)	0.20
Chloride	0.22 ^(c)	22.20
f.a. Chlorine ^(d)	0.0062 ^(b)	0.624
Sulfate	0.466 ^(b)	47.10
Cyanide	--	--
Thiocyanate	--	--
Fluoride	--	--
Fe	6.5×10^{-4} ^(b)	6.6×10^{-2}
Cu	6.5×10^{-4} ^(b)	6.6×10^{-2}
Zn	8.2×10^{-4} ^(b)	8.4×10^{-2}
Cr	1.07×10^{-3} ^(b)	0.109
P	8.35×10^{-3} ^(b)	0.843
Na	0.248 ^(c)	25.9
Ni	8.42×10^{-3} ^(c)	0.85
Mg	0.201 ^(c)	20.3
Al	2.0×10^{-3} ^(c)	0.201
Mn	7.0×10^{-5} ^(c)	7.04×10^{-3}
Cd	2.0×10^{-5} ^(c)	2.01×10^{-3}
Se	7.0×10^{-5} ^(c)	7.04×10^{-3}
As	2.0×10^{-5} ^(c)	2.0×10^{-4}
B	8.3×10^{-4} ^(c)	8.4×10^{-2}
Pb	2.0×10^{-5} ^(c)	2.0×10^{-3}
Ba	1.2×10^{-4} ^(c)	1.2×10^{-2}
Hg	1.6×10^{-6} ^(c)	1.6×10^{-4}
Be	3.3×10^{-6} ^(c)	3.2×10^{-4}
V	1.67×10^{-5} ^(c)	1.6×10^{-3}

(a) ANL (1977 Draft).

(b) Assumes compliance with New Source Performance Standards.

(c) Assumes uncontrolled discharge.

(d) Free available chlorine.

TABLE 5.27. Solid Wastes from Coal-Fired Power Plant
(tons/10¹² Btu output energy)^(a)

<u>Solid Waste</u>	<u>Without Scrubbing</u>	<u>With Lime Scrubbing</u>
Bottom Ash	2441.1	2441.1
Fly Ash	8735.2	8735.2
Scrubber Sludge	0	2511.0

(a) U.S. DOE 1980.

potentially useful by-product are available, markets for the recovered sulfur or sulfuric acid are not always available. FGD by-products from remote Western power plants most likely will be disposed of as waste because transportation costs often exceed the value of the product. Power plants near Midwest load centers will have a greater possibility of finding a market for their FGD by-products, although specific sites and potential consumers must be considered to determine possible economic incentives.

Most plants producing FGD wastes from nonregenerable scrubbing systems use some form of ponding or landfill for disposal. The first ponds were unlined but because of concern over possible groundwater contamination, recent ponds have liners of low permeability such as clay, plastic or rubber. Some utilities have also chosen to chemically fix FGD wastes because of improved structural properties and resistance to leaching.

Potential pollutants from untreated FGD wastes included soluble trace elements, chemical oxygen demand from sulfates, high levels of total dissolved solids, and excessive levels of some major chemicals (sulfate, chloride, calcium, magnesium, sodium)(Jones 1977). Table 5.28 shows typical leachate analyses of untreated FGD waste from a lime scrubbing system. The analyses represent maximum observed levels and are compared to National Interim Drinking Water Regulations and 1962 U.S. Public Health Service Drinking Water Standards. The data show that untreated FGD wastes have the potential to exceed drinking water standards for these constituents.

TABLE 5.28. FGD Leachate Analysis Compared to Drinking Water Standards^(a)

<u>Constituent</u>	<u>Selected Pond A^(b) Leachate Analyses, mg/l</u>	<u>National Interim Drinking Water Regulations, mg/l</u>	<u>1962 U.S. Public Health Service Drinking Water Standards, mg/l</u>
Arsenic	0.08	0.05	0.05
Mercury	0.0067	0.002	0.002
Selenium	0.013	0.01	0.01
Lead	0.062	0.05	0.05
Sulfate	980	--	250
Chloride	3500	--	250

(a) Jones 1977.

(b) Contains untreated wastes from a lime scrubbing FGD system.

Research is being conducted to evaluate disposal alternatives for FGD wastes. Both landfill disposal and mine disposal are being actively considered. Preliminary results from an Arthur D. Little study show that active Midwest surface coal mines and active Midwest and Eastern room and pillar mines are promising disposal sites (Jones 1977). Western surface mines were also considered as potential disposal sites, but lower annual rainfall in the West may result in insufficient dilution of leachate (Jones 1977). Although disposal of FGD wastes in mines has been considered by some utilities, several utilities that were considering mine disposal sites decided in favor of settling ponds closer to the power plant.

On December 18, 1978, the EPA proposed hazardous waste regulations under the Resource Conservation and Recovery Act (RCRA) of 1976. Portions of these regulations apply to the disposal of fly ash and flue-gas desulfurization wastes from electric power plants. The regulations establish guidelines for site selection, security, recordkeeping and reporting, and groundwater and leachate monitoring. The regulation will apply to an estimated 270,000 waste generating sources (Environment Reporter 1978b).

The EPA currently has very limited information on the composition characteristics and the degree of hazard posed by utility wastes. As a result, utility wastes will be subject to "special waste standards." These standards will be published at some later date and will include guidelines for treatment, storage and disposal of special wastes.

Heavy trace metals were cited as a potentially hazardous substance in utility wastes (Environment Reporter 1978b), although a recent study done for the EPA by the Radian Corporation concluded that most coal-fired utility wastes appear to be nonhazardous (Jones et al. 1978).

The full cost impacts to utilities are uncertain. However, stricter containment and disposal procedures for FGD wastes will certainly evolve. Current estimates of capital costs for FGD wastes and ash disposal for coal-fired power plants range from 10 to \$50/kW. The capital and operating costs for the fixation and disposal of FGD solids for a 1000 MW unit have been estimated at 2.07 to \$3.24 per ton of coal burned (Breitstein et al. 1977). The Radian report estimates that capital costs associated with disposal of utility wastes in compliance with RCRA will increase 36% (Environment Reporter 1979b).

Other requirements for the disposal of ash and spent slurry can be measured by the amount of land needed for disposal and the cost of disposal equipment. Table 5.14 lists the land requirements for ash and sludge disposal for the 35-year life of a 1000 MW plant for both current and proposed air-quality regulations. Solid waste information for recovery processes was unavailable because most sources assumed the sale of the by-products. Fly ash used as a scrubbing agent is disposed of with the spent slurry.

5.4.5 Accident Rates

Major accidents in coal-fired power plants generally result from explosions in a boiler, turbine, or generator. Other accidents may occur from misuse of equipment or machinery necessary for operation and maintenance. Annual accident rates associated with a 1000 MW coal-fired power plant are 0.03 to 0.17 fatalities, 1.2 to 3.3 nonfatal injuries, and 350 to 750 mandays lost (Bliss et al. 1977).

5.4.6 Noise Impacts

Power plant noise can be classified as either occupational or community annoyance. The Occupational Safety and Health Act of 1970 set a limit of 90 dBa/8-hr day as the maximum noise exposure level for workers (Smith and Dennison 1975). The EPA Office of Noise Abatement Control (EPA-ONAC) set the ideal upper limit for noise exposure for industrial workers at 80 dBa/8-hr day. The interim goal has been set at 85 dBa/8-hr day. In addition, EPA-ONAC suggests a maximum community day-night sound level of 55 dBa/8-hr day (Smith and Dennison 1975). Although national regulations may emerge, noise regulations are currently the responsibility of states and local communities where they are often implemented as performance standards attendant to zoning regulations.

Cooling towers have been identified as being one of the noisiest power plant components for the surrounding community. Recorded noise levels from various cooling systems are presented in Figure 5.20. No major differences appear to exist between the sound levels from mechanical and natural draft cooling tower. All of the 16 towers that were monitored fall into a fairly narrow range of about 3 dBa. Figure 5.20 shows that sound levels drop off to about 55 dBa at a distance of 1000 ft from the towers.

Proper spacing of power plant components can preclude noise disturbances for surrounding communities. Where land is a serious constraint, noise reduction equipment can be obtained for cooling towers. The cost of towers that use this equipment has been estimated at 10 to 15% above standard tower costs (Capano and Bradley 1976).

5.4.7 Visual Impacts

The visual impact of power plants, most notably the cooling towers and plumes, is evident but very difficult to quantify. One study used a bidding method to assess visual impacts (Adams et al. 1979). Individuals were asked to rate photographs (landscapes and cooling towers) according to visual appeal. In addition, individuals were asked to bid on these photos in terms of willingness to pay for reduction in impact and willingness to accept compensation for persisting impact. This study concluded the following:

FIGURE 5.20. Noise Levels from Cooling Towers

- A change from a mechanical draft tower (no plume) to a natural draft tower (no plume, but much larger profile) had a negative impact.
- A change from either a mechanical or natural draft tower with no plume to either tower with a visual plume had a negative impact.
- Willingness to pay to avoid negative visual change was significantly less than the willingness to accept compensation for perceiving a negative visual change.
- Visual change impact caused by the addition of cooling towers is relatively minor when compared to growth, employment, health and safety issues.

Although the visual character of cooling towers appears to have negative attributes, they appear to be less significant than other environmental impacts, with the possible exception of areas of high visual quality.

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6.0 ELECTRIC POWER TRANSMISSION

In this chapter bulk straightaway electric power transmission over long distances between points of generation and utilization is discussed. Conceptual high voltage alternating current (HVAC) and high voltage direct current (HVDC) systems that would fulfill the transmission requirements of this study are described and their costs estimated. The transmission is assumed to traverse either of two terrains. Terrain "I" would be comprised of 50% flat terrain and 50% rolling, and Terrain "II" would be made up of 50% rolling and 50% mountainous terrain. Material resource requirements and environmental effects of the transmission lines and stations are discussed.

6.1 ASSUMPTIONS

This study is based on delivery of 10,000 MW of electric power over distances of up to 1000 miles. While cost estimates are for 1980 conditions, the relationships are applicable to the years 1990 and beyond. Both HVAC and HVDC are suitable technologies for this transmission application. HVAC has had wide use at voltages as high as 765 kV and may be less costly than HVDC for transmission distances up to perhaps 500 miles at the indicated power level. While thoroughly proven, the state of development of HVDC is not as well accepted as is that of HVAC. HVDC has been used in a relatively few situations, such as for long distance bulk power transport, overhead or under water, and for asynchronous connections. Experience with HVDC has demonstrated its reliability, operating characteristics and application advantages. Clearly, the technology should be applied where economics and operating considerations so indicate. Technological improvements in HVDC, such as advances in semiconductor valve capacity, have helped to shield HVDC converter stations from most of the cost inflationary influences experienced elsewhere in the electric utility industry.

6.1.1 Load Factor

The load factor (average load divided by peak load) of the system is assumed to be 90%. This is consistent with utilization assumptions for other

energy transport systems in companion studies. Cost calculations are also shown for load factors of 70% and 80%.

6.1.2 Reliability and Reserve Capacity

The rated capacity of a system and its costs are affected by the reliability standards adopted for its design and operation. Sufficient reserve capacity must be available, if it cannot be found in existing contiguous systems, to permit the transmission of planned power quantities during any reasonably expected line or equipment outages. For this study we assume no alternate power flow paths in adjacent transmission systems that would provide backup support in the event of an outage. For double contingency outages, one of which would be of long duration and the other short; the remaining lines and station facilities must be capable of carrying the entire load with a sufficient margin of reliability to successfully withstand the second short duration outage in the same transmission section. That is, the system, while operating under maximum rated load, must tolerate a long time outage of one section of AC line or one pole of an HVDC bipole, plus a second contingency that would involve a second fault with rapid return to service by high speed reclosing of another line section, or its equivalent in the HVDC case.

In HVAC transmission systems, such as considered in this study, three-phase electric power would be generated at 25 kV, transformed to a transmission voltage of 345, 500, 765 or 1100 kV, and transmitted distances of 250, 500, 750 or 1000 miles to a receiving network of 345 or 500 kV. Suitable step-down transformers would be applied at the receiving end for the 765 and 1100 kV transmission cases.

In theory, electric power could be transmitted over a simple three phase transmission line for hundreds of miles if its loading could be maintained without change at its natural power, or surge impedance loading (SIL). For this condition, the reactive power supplied by the line shunt capacitive susceptance, B_C , would be equal to the reactive power consumed by flow of load current through the inductive reactance, X_L , of the circuit.

Most transmission line loadings under present-day practice are at or less than SIL and rarely are transmitted over distances greater than 150 miles without power input or equivalent support at intermediate points of the transmission.

Greater quantities of electric power may be transmitted over longer distances by building additional parallel transmission lines or by artificially increasing the SIL to agree with the existing, higher load on the line by compensating it. E. W. Kimbark (1983) discusses the basic considerations for application of compensation to power transmission. The first alternative is by far the most expensive. The second is usually most cost effective by an appreciable margin.

6.2 HVAC TRANSMISSION

6.2.1 Shunt and Series Compensation - AC Power Transmission

In 1921 Frank G. Baum (1921) proposed shunt compensation of large power, long distance transmission systems. This would be done by holding the voltage essentially equal at all busses in the transmission, including the intermediate compensator stations, by feeding reactive power into the busses. Transmission distance would be extended and transmitted power limits raised. At that time, synchronous compensators (condensers) provided the only practical means for shunt compensation. Because their response to transient changes on the power system was relatively slow, the idea was not widely applied as a means for making long distance power transmission more feasible. While the power system could operate satisfactorily at higher loadings than under the then existing practices in the steady state with synchronous compensators, the power system transient performance would not have been acceptable.

In the last few years, development of the thyristor switch and static var systems (SVS) has made it possible and economically practical to apply Baum's shunt compensation idea using these devices. The SVS permit operation of transmission systems at SILs appropriate to the line loadings both under normal steady state as well as during transient conditions when transient and dynamic stability become important operating considerations.

Much greater quantities of power can be transmitted over longer distances in the steady state with compensation than without it. Moreover, the inherently high speed of the response of SVS thyristors and their controls, 0.5 to 2.0 cycles of the power frequency, greatly improves the power system's transient and dynamic stability so that it can safely withstand fault and switching disturbances at much higher loadings. In short, SVS permit the system planner and operator to use more of the inherent conductance in the higher voltage circuits and achieve large cost savings as well. Under this concept, the main operating constraint would likely be the conductor thermal limit.

Shunt compensation enhances power transmission capabilities by providing voltage support at intermediate stations to maintain a near-uniform voltage profile over the transmission line. The compensated SIL is increased as required for the system loading; that is, the reactive power supplied to the line is increased to compensate for the increased reactive power consumed in the line reactance due to the greater load flow.

Another method of compensation is by reducing the effective inductive reactance of the line by series compensation. This is accomplished by placing static capacitors of appropriate size and rating in the line, in series with the reactance of the line, to effectively cancel a part of its inductive reactance. In most cases, series compensation entails a fixed degree of compensation compared with the continuously adjustable compensation (within the operating limits) of SVS shunt compensation. A single step of change of series compensation from its normal value has been used in a few high capacity transmission lines to further enhance system stability by placing a smaller, normally bypassed capacitor in series with the main series capacitor. When needed, such as during major system disturbances, automatic controls open the bypassing switch, thus inserting additional series compensation into the transmission line to increase the compensation from perhaps 50% to 75% of the line's inductive reactance. This greatly strengthens the compensated line's role in preventing instability. The degree of compensation possible from a given amount of static capacitance is the same whether applied in the series or shunt configuration.

Most applications of series compensation have treated the series capacitors as part of the transmission line by placing them in the middle third of the compensated line. Protective relaying for the transmission line is simpler and excursions are less from a uniform voltage profile on the line. However, when the line is automatically removed from service after a line fault, the series capacitors are lost to the power system as a source of reactive power along with the line. This lost reactive source could be important to the remaining in-service parts of the power network when its need for reactive power has suddenly increased. Higher loading limits are possible with a smaller investment in series capacitors, if such reactive power sources could be kept in service during and after line faults. For example, if the series capacitors are installed at the sectionalizing stations so that they compensate several lines, but are not switched out, they would not be lost to the system when a faulted line is taken out of service.

Subsynchronous resonance (SSR) has been recognized in the last few years as a possible serious problem for steam turbine-generators connected to heavily compensated transmission lines. The SSR risk is considered less with shunt than with series compensation. However, when planning to apply compensation, especially for long distance transmission, this risk should be carefully studied and appropriate corrective or protective actions taken.

A system layout showing typical system elements for the AC transmissions considered in this study is shown in Figure 6.1. Several compensating devices are shown: switchable reactors at each line terminal for light load compensation; series capacitors in each line; capacitor banks for shunt compensation; and the SVS for continuous, rapidly adjustable shunt compensation.

6.2.2 Conductors

We assume use of aluminum-conductor, steel-reinforced (ACSR) transmission overhead line cables for all configurations examined. Multiconductor bundles, with individual conductors spaced 18 to 24 inches apart, but electrically connected every 50 to 100 feet, are used in each of the three phases for the 500, 765, and 1100 kV systems. Pertinent data on the individual conductors, identified by their industry-standard "bird" names, are given in Table 6.1.

TABLE 6.1. Conductor Data

Conductor	Diameter (in.)	Area (circular mils)	Resistance at 25°C (Ohms/mi)	
			DC	AC
Drake	1.108	795,000	0.1180	0.1190
Bunting	1.302	1,192,500	0.0787	0.0811
Chukar	1.602	1,780,000	0.0516	0.0549
Thrasher	1.802	2,312,000	0.0397	0.0446

Electrical characteristics of the AC conductor configurations in this study are shown in Table 6.2. Data for these tables were developed from information in Transmission Line Reference Book, 345 kV and Above (EPRI 1982b).

6.2.3 Advanced Technology for HVAC Transmission

HVAC technology at voltages of 765 kV and below is well established in the United States. Research at 1200 kV and above for lines and equipment has been in progress in the U.S. since 1967. The Waltz Mill Facility in Pennsylvania serves as a prototype for 1200 kV design. Project UHV in Pittsfield, Massachusetts, is engaged in evaluating line parameters up to 1500 kV. The AEP-ASEA

TABLE 6.2. Electrical Characteristics - AC Conductor Configurations

	Resistance at 25°C (Ohms/mi)	Inductive Reactance (Ohms/mi)	Susceptance, B B, (Mhos $\times 10^{-6}$ /mi)
345 kV 1 C Bunting	0.0811	0.795	5.3447
1 C Chukar	0.0549	0.768	5.5249
500 kV 3 B Bunting ^(a)	0.0270	0.534	7.5247
3 B Chukar	0.0183	0.524	7.9554
765 kV 4 B Chukar	0.0137	0.530	7.8247
4 B Thrasher	0.0112	0.526	7.8802
1100 kV 8 B Chukar	0.0069	0.435	9.4967
8 B Thrasher	0.0056	0.433	9.5420

(a) "3 B Bunting" signifies three Bunting conductors in the bundle, for example.

test station near Lakeville, Indiana, is investigating line design requirements for voltages up to 2000 kV. The Bonneville Power Administration (BPA) has built and operated a 1.3 mile 1100 kV test line adjacent to its Santiam Substation since December 1976. A section for mechanical tests of 1100 kV lines was also built near Moro, Oregon, in the same period.

Studies thus far indicate that 1100 kV appears feasible. Assuming positive results from the various test programs, an operating 1100 kV line may be expected in the mid- to late-1990s.

6.3 HVAC LOAD FLOW STUDIES

Load flow calculations were made of voltages, currents, angular relationships, power flow, losses, and reactive power compensation and consumption using equivalent pi transmission constants. (See Westinghouse's (1964) Electronic Transmission and Distribution Reference Book.) All of the cases considered were for steady state conditions.

Basic criteria for these studies required or assumed satisfactory operation of the transmission for 1) transmission of 10,000 MW at 90% load factor over distances of 250, 500, 750, and 1000 miles at nominal voltages of 345, 500, 765, and 1100 kV, 2) full load losses at 20°C ambient temperature, 3) emergency loading for double contingency outages, including a long time outage of any one line section between sectionalizing stations, accompanied by not more than one other line section outage that would be high-speed reclosed automatically, 4) conductor maximum temperature limited to 50°C rise over 40°C ambient temperature under maximum loading with a long time outage of any one line section, and 5) sectionalizing at 200 miles or less.

The operating characteristics of the various conductor configurations are given in Table 6.3.

6.3.1 Load Flow Study Results

The minimum number of AC lines required for transport of 10,000 MW for each distance and transmission voltage are shown in Table 6.4.

Compensation for conditions considered in this study would require leading reactive power for those configurations with natural SILs less than the system

TABLE 6.3. Operating Characteristics - Single AC Circuit

Operating Voltage (kV)	Conductor	Line Charging (per 100 miles)		Surge Impedance (Ohms)	SIL ^(a) (MW)	Loading Limit (MW) ^(b)
		Current	3 Phase			
345	1 C Bunting	105 A	63	385	309	690
	1 C Chukar	110	66	375	317	870
525	3 B Bunting	215	195	290	950	3,150
	3 B Chukar	240	218	255	1,080	4,000
765	4 B Chukar	345	457	260	2,250	7,700
	4 B Thrasher	350	464	258	2,270	9,300
1100	8 B Chukar	600	1,143	214	5,650	22,200
	8 B Thrasher	605	1,153	213	5,680	26,700

(a) SIL is the surge impedance or natural uncompensated loading.

(b) Loading limit is based on a maximum conductor temperature rise of 50°C above an ambient temperature of 40°C.

TABLE 6.4. Number of HVAC Transmission Lines Required
(10,000 MW transmitted)

Conductor	1000 Miles	750 Miles	500 Miles	250 Miles
345 kV 1 C Bunting	-	-	23	23
1 C Chukar	-	-	19	19
500 kV 3 B Bunting	8	8	8	8
3 B Chukar	7	7	7	7
765 kV 4 B Chukar	4	4	4	4
4 B Thrasher	4	4	4	4
1100 kV 8 B Chukar	3	3	3	3
8 B Thrasher	3	3	3	3

loading and lagging reactive power loads for SILs that are greater, as in the 1100 kV cases. To maintain a high power transfer capability, SVSs would be sized and applied so that they could compensate with minimum delay for the sudden changes in reactive power requirements that would follow fault-initiated line outages.

Table 6.5 shows compensation required for 10,000 MW load on the system under normal conditions, that is, with all lines in service, as well as total compensating capacity required for a long time outage of any one line section. Table 6.6 lists the lagging reactive power loads required for compensation of the system when it is operating at no load.

HVAC system losses are due mainly from flow of line current through the resistance of the line conductors. This study adjusts these losses for temperature rise over the assumed ambient temperature, 20°C, from the current in each conductor. Small additional losses were assumed for corona and in the 765 and 1100 kV transformers. The calculated total losses for each voltage and conductor configuration for the four transmission distances are shown in Table 6.7. These system configurations and data, along with operating and maintenance estimates, form the basis for the following cost estimates.

6.4 HVDC TRANSMISSION

HVDC transmission systems and concepts that have been analyzed are discussed in this section.

6.4.1 Technology -- HVDC Transmission

In the HVDC transmission systems examined, AC power would be received from the generating station at 345 kV. It would then be rectified for DC transmission to the receiving inverter station. There, it would be converted from direct current to 60 Hz alternating current. Then, it would be transformed, if necessary, to the voltage of the receiving network, assumed to be 345 or 500 kV, and delivered to the receiving AC system for distribution.

Normally the power flows over a bipolar circuit (i.e., two conductors), one of which carries the outgoing direct current at the designated DC voltage above ground potential. The other conductor provides the return path for current flow at the designated voltage below ground potential. When one pole of the DC transmission is removed from service, as for a line fault, the other pole can continue to operate in the monopolar mode with current return through the earth or ground at approximately half the rated power of the bipolar circuit. Operation in this manner is usually limited to one or two hours because

TABLE 6.5. Total Compensation Added--10,000 MW Transmitted Power^(a)

Conductor	1000 Miles		750 Miles		500 Miles		250 Miles	
	Normal (MVAR)	Outage ^(b) (MVAR)	Normal (MVAR)	Outage ^(b) (MVAR)	Normal (MVAR)	Outage ^(b) (MVAR)	Normal (MVAR)	Outage ^(b) (MVAR)
345 kV 1 C Bunting (23 circuits)	--	--	--	--	+11800	+13900	+5800	+6800
345 kV 1 C Chukar (19 circuits)	--	--	--	--	+14100	+16300	+6600	+7600
525 kV 3 B Bunting (8 circuits)	+11250	+15200	+8000	+11000	+5200	+6900	+2800	+4400
525 kV 3 B Chukar (7 circuits)	+15200	+23600	+10800	+17000	+7000	+11000	+3500	+5400
765 kV 4 B Chukar (4 circuits)	+6400	+18000	+4700	+13200	+3200	+9000	+1800	+4600
765 kV 4 B Thrasher (4 circuits)	+5300	+20300	+3700	+14500	+2200	+9200	+1050	+4300
1100 kV 8 B Chukar (3 circuits)	-20300	+18100	-14800	+13500	-9300	+9000	-4100	+2200
1100 kV 8 B Thrasher (3 circuits)	-20600	+18100	-15000	+13500	-9500	+9000	-4200	+2200

(a) Positive "+ MVAR" is leading reactive power--negative "-MVAR" is lagging reactive power.

(b) Reactive power capacity required for single line section long time outage.

TABLE 6.6. No Load Compensation--Required Lagging Reactive Power Load

Conductor	1000 Miles (MVAR)	750 Miles (MVAR)	500 Miles (MVAR)	250 Miles (MVAR)
345 kV 1 C Bunting (23 lines)	--	--	-6400	-2900
345 kV 1 C Chukar (19 lines)	--	--	-5250	-2400
525 kV 3 B Bunting (8 lines)	-15750	-11300	-7300	-3250
525 kV 3 B Chukar (7 lines)	-14000	-10000	-6500	-2900
765 kV 4 B Chukar (4 lines)	-14400	-10500	-6600	-3000
765 kV 4 B Thrasher (4 lines)	-16850	-12250	-7750	-3500
1100 kV 8 B Chukar (3 lines)	-11200	-7800	-5200	-3500
1100 kV 8 B Thrasher (3 lines)	-11000	-7700	-5100	-2400

TABLE 6.7 HVAC System Losses (MW) at Maximum Load (10,000 MW) (calculated for actual line currents under an ambient temperature of 20°C)

Conductor	1000 Miles (MW)	750 Miles (MW)	500 Miles (MW)	250 Miles (MW)
345 kV 1 C Bunting (23 lines)	--	--	1974	895
345 kV 1 C Chukar (19 lines)	--	--	1546	712
525 kV 3 B Bunting (8 lines)	1419	1029	667	327
525 kV 3 B Chukar (7 lines)	1082	790	515	253
765 kV 4 B Chukar (4 lines)	713	539	369	208
765 kV 4 B Thrasher (4 lines)	625	471	322	179
1100 kV 8 B Chukar (3 lines)	370	285	200	117
1100 kV 8 B Thrasher (3 lines)	336	259	184	109

of the possibility of corrosive interaction of the current with subsurface metallic structures near the HVDC system ground electrodes. Consequently, strenuous efforts are made to locate the ground electrodes remotely from such structures--at least 5 to 10 miles distant, if possible.

As in AC transmission, the resistance of the line conductors to the flow of current causes energy loss as heat, which varies the temperature of the conductors. If the current becomes sufficiently large, the conductor temperature rise limits the load-carrying capacity of the line. The ambient temperature plus the temperature rise above ambient determines the maximum temperatures in the conductors. Instability, as in a heavily loaded AC line, is not a constraint on operation of HVDC power transmission. Instead, DC line loadings are usually limited so that the conductor temperature does not exceed a rise of 50°C (approximately) over an ambient temperature of 40°C.

In addition to thermal effects, the current flow through the line resistance causes a voltage drop equal to the product of line current, "I" in amperes, times the conductor resistance, "R" in Ohms. This is equal to the voltage drop over the length of the transmission line. DC power flow in the transmission line is closely controlled by adjusting the voltage difference between the converter (rectifier and inverter) stations.

The conversion process generates harmonic currents and voltages that, if not controlled, can be injected into the AC systems or the DC line to cause interference. Consequently, most converter stations are fitted with harmonic filters that essentially confine the flow of harmonics to the stations. Because the converters consume large amounts of reactive power, reactive power sources such as capacitor banks are installed on the AC sides of the converters.

Applying the DC technology for power transmission requires the use of major components such as those shown in the one-line diagram of a typical DC transmission bipole in Figure 6.2.

6.4.2 Conductors

Conductors for DC overhead lines are of the same type that are used for AC lines. In this DC application study, four ACSR cables were used: Drake,

FIGURE 6.2. One-Line Diagram of a Typical HVDC Bipolar Transmission System

Bunting, Chukar, and Thrasher. (See Table 6.1 for data on these conductors.) The bundling arrangements used are given in Table 6.8.

6.4.3 Advanced Technology for HVDC Transmission

Manufacturers have been notably successful in developing semiconductor DC technology. Improvements in the thyristors themselves indicate this. They have gone from 1700 volt, 800 ampere thyristors in the semiconductor converters of the early 1970s to 4400 volt, 4000 ampere thyristors in today's units. Such improvements permit high-capacity converter designs without the complexity of paralleling thyristors. These and other related advances have kept converter price increases well below those seen elsewhere in the electric utility industry.

A second area of research in DC transmission is directed at system voltages beyond the ± 600 kV level in anticipation of the possible need for higher power HVDC applications. For example, research sponsored by EPRI is aimed at identifying problem areas and their solutions for this higher voltage range.

Actual cost information of DC equipment at voltages greater than ± 600 kV is nonexistent. At these levels, several factors become quite important to costs. Among these, switching surge clearances will likely require appreciably larger valve buildings or perhaps greater use of SF_6 for insulation. Converter transformer insulation for the higher DC voltages will present demands that inevitably will be reflected in increased costs. Cost estimates for these studies of ± 750 kV converter stations take into account these factors.

TABLE 6.8. HVDC Conductor Bundling Arrangements

<u>Nominal Voltage Class kV</u>	<u>Conductor</u>
± 400	2 B Chukar 2 B Thrasher
± 500	2 B Thrasher 3 B Chukar
± 600	3 B Chukar 4 B Chukar
± 750	6 B Drake 6 B Bunting

6.5 HVDC SYSTEM MODEL

The HVDC systems examined in this study differ from the HVAC systems in that there are no intermediate sectionalizing stations nor are there any direct interconnections between the DC lines. In the analysis, the transmission system was treated as consisting of simple DC circuits, the final number of lines and the system losses being determined by an iterative process to achieve the required delivered power and DC voltages. One of the constraints was the conductor temperature assumed for emergency conditions.

From these calculations, the HVDC bipole system that is necessary for transmission of 10,000 MW for the various voltage and conductor combinations is shown in Table 6.9. Total system losses are also given for each combination. These include losses caused by the flow of current through the line conductor resistance, converter losses assumed at 0.95% of station capacity, and a small allowance for corona losses.

TABLE 6.9. HVDC Transmission Lines and Total System Losses (MW)

Conductor	1000 Miles		750 Miles		500 Miles		250 Miles	
	No.	Losses	No.	Losses	No.	Losses	No.	Losses
±400 kV 2 B Chukar	-	--	-	--	-	--	4	897
	-	--	-	--	5	1342	5	697
±400 kV 2 B Thrasher	-	--	-	--	4	1330	4	692
	-	--	-	--	5	1002	5	564
±500 kV 2 B Thrasher	3	2922	3	1859	3	1156	3	623
	4	1678	4	1214	4	825	4	489
±500 kV 3 B Chukar	3	1995	3	1402	3	928	3	533
	4	1342	4	1004	4	704	4	436
±600 kV 3 B Chukar	2	2342	2	1581	2	1018	2	568
	3	1258	3	947	3	670	3	421
±600 kV 4 B Chukar	2	1448	2	1069	2	741	2	452
	3	929	3	725	3	536	3	359
±750 kV 6 B Drake	2	1335	2	998	2	700	2	434
	3	888	3	698	3	520	3	352
±750 kV 6 B Bunting ^(a)	2	897	2	703	2	522	2	352
	3	656	3	534	3	416	3	302

(a) 6 B Bunting denotes 6 individual Bunting cables in a conductor bundle, for example.

6.6 ECONOMICS OF ELECTRIC POWER TRANSMISSION

This section contains estimates of capital and annual costs for HVAC and HVDC systems for transport of 10,000 MW over distances of 250, 500, 750, and 1000 miles at load factors of 70, 80, and 90%. Estimates are for complete electric power transmission systems and include costs of transmission lines, HVDC converter stations, HVAC terminal and intermediate switching stations, as well as for series capacitor stations. Costs are developed from the unit cost data presented in Table 6.10 for the transmission lines and AC equipment and from Figure 6.3 for HVDC converter stations.

The capital cost estimates include circuit breakers, transformers, land, station structures and buildings, converter terminals, reactive power compensation, and a 10% allowance for interest during construction. The annual costs include capital recovery costs at 15% and 18%, the costs of system losses and O&M requirements. Cost estimates are in 1980 dollars, with no provision for cost escalation. Capital cost treatment assumes a 10% allowance for interest during construction.

6.6.1 Operation and Maintenance

O&M costs cover staffing for maintenance of transmission lines, substations, relays and meters, telecommunications and controls, in addition to operation and dispatching and management and clerical functions. Staffing assumes no electrical facilities other than those in the transmission system and its associated generating plant.

Transmission maintenance crew requirements are a function of the transmission distance. The influence of the number of lines on manpower plans is not as great as the geographic distance that each crew must normally cover in its work. For example, 3 crews of 8 persons each should be adequate for the 750 and 1000 mile cases and 2 crews for the 250 and 500 mile systems.

Substation maintenance staff requirements are determined primarily by high voltage switching, transformation, or HVDC conversion facilities. For AC transmission of 1000 miles with 3 lines, a staff of 28 to 30 people would be adequate, while a 250 mile system might need about 16 people.

TABLE 6.10. Unit Cost Assumptions

a) Transmission Lines (BPA 1979)--\$/Mile

Conductor	Terrain		
	Flat	Rolling	Mountainous
<u>HVDC</u>			
±400 kV 2 B Chukar	\$ 151,900	\$ 221,400	\$ 281,000
2 B Thrasher	167,800	239,200	300,200
±500 kV 2 B Thrasher	171,800	244,800	308,000
3 B Chukar	198,100	276,900	344,100
±600 kV 3 B Chukar	215,700	303,100	376,300
4 B Chukar	249,700	346,800	425,800
±750 kV 6 B Drake	265,800	374,000	464,800
6 B Bunting	294,800	413,800	510,400
<u>HVAC</u>			
345 kV 1 C Bunting	\$ 205,200	\$ 251,800	\$ 287,500
1 C Chukar	253,800	311,800	355,600
500 kV 3 B Bunting	234,000	297,700	350,100
3 B Chukar	289,400	355,100	410,500
765 kV 4 B Chukar	388,600	495,100	561,900
4 B Thrasher	438,000	547,500	617,100
1100 kV 8 B Chukar	1,023,400	1,247,200	1,408,200
8 B Thrasher	1,132,600	1,364,400	1,531,000

Note: For transmission configurations in this study, Terrain I is assumed to consist of 50% flat and 50% rolling terrain, and Terrain II 50% rolling with 50% mountainous.

b) HVDC terminal cost data may be found in Figure 5.3.

c) HVAC Substation and Compensating Equipment - (Based on manufacturers' data, EPRI (1982), and Commonwealth Associates, Inc. (1979).

Voltage (kV)	Power	Transformers (\$/kVA)	Added % For Land and Structures ^(a)
	Circuit Breakers (\$/line section)		
345 kV	\$2,085,000	--	45
500	4,155,000	--	45
765	5,250,000	6.60	40
1100	9,000,000	9.00	25

(a) These percentages to be added to station estimates to cover cost of land, structures, buildings, communications, control, etc.

Reactive Compensation - \$/KVAR

Voltage	Shunt Reactors	Series Capacitors	Shunt Capacitors	Static Var Systems - (SVS)
345 kV	\$4.00	\$10.00	\$ 5.00	\$22.00
500	5.00	12.00	6.00	24.00
765	6.60	15.00	9.00	26.00
1100	9.00	20.00	12.00	30.00

FIGURE 6.3. HVDC Terminal Cost Data, C_T in $\$/\text{MW}$, As Functions of the Terminal Capacity, P_T , in MW

The remaining craftsmen, engineers, and other staff involved in operating and maintaining such a system would be determined in a similar way. Management and clerical staffing would not change greatly for the systems studied.

Overall, O&M costs do not have great influence on total annual costs for the power transmissions studied since they only represent approximately 1 to 1.5% of the total.

6.6.2 Power Loss Costs

The cost of system losses for each of the AC and DC systems includes costs for lost energy, transmitting the energy lost, and additional generating capacity to supply the energy losses. Losses were evaluated using the following parameters:

Capacity cost	\$1097/kW
Fixed O&M cost	\$9.50/kW/yr
Fuel cost	\$0.006/kWh
Variable O&M cost	\$0.0017/kWh

Losses are assumed to be transmitted half the distance for each transmission. The annual fixed charge rate on capital investment is 15 or 18%. A 90% load factor and 81.9% loss factor (the factor relating average loss to the loss rates at various load levels) were used. Calculations for load factors of 70 and 80% were also made.

6.6.3 Land Requirements

Typical right-of-way assumptions are discussed in Section 6.7.1 for HVAC and HVDC systems. The value of land, over which such lines might be expected to pass, would range from about \$100 per acre for undeveloped range land to possibly \$10,000 per acre for suburban or agricultural land. Because this study is not site specific, its land costs vary from \$2000 to \$3200 per acre. Land cost totals are then fixed by the right-of-way areas, from 11 to 24 acres per mile of AC lines, and from 14 to 19 acres per mile of DC line. Such land costs are included in the line construction unit cost estimates given in Table 6.10.

6.6.4 Cost Estimates - Electrical Transmission

Tables 6.11 to 6.14 give the total capital and annual costs for the HVDC and HVAC configurations examined (8 of each). The costs shown for each conductor arrangement, e.g., ± 400 kV 2 B Chukar - 5 circuits, were selected on the basis of minimum annual cost in comparison with other cases involving different numbers of circuits.

From these tables, a final selection was made of the least-cost HVDC and HVAC conductor configuration, voltage, and number of lines for each transmission distance, Terrains I and II, and 15 and 18% annual capital costs. The results of this final selection are shown in Table 6.15. As the table indicates, the economic crossover distance in which the costs of HVDC are less than those of HVAC electric energy transport systems would be greater than 600 to 700 miles for a load of 10,000 MW operating at 90% load factor.

Capital costs for reactive power compensation are also given in Table 6.15 for the least costly 10,000 MW HVAC transmissions. The costs range from 13 to 20% of the total capital that would be required to construct these AC systems. The transmission loss costs are given in Table 6.16. They range from 11 to 23% of the total annual HVDC costs and from 7 to 17% of the total annual HVAC costs.

6.7 RESOURCE REQUIREMENTS

The resources required for electric power transmission include land, major construction materials and construction manpower. These requirements will vary depending upon site-specific conditions, the number and types of lines, and the system design.

6.7.1 Land

Electric power transmission systems require land for the transmission line right-of-way and for terminals and intermediate stations. Roads are usually needed for access to the transmission line and station structures. Where possible, existing rural (farm or logging) roads are used, although additional access roads from 12 to 16 feet in width are usually required. In heavily

TABLE 6.11. Capital and Annual Costs--Transmission 250 Miles (millions of dollars)

Conductor	Load Factor	18% Annual Cost						15% Annual Cost					
		Terrain II			Terrain I			Terrain II			Terrain I		
		Ccts (a)	Capital Costs	Annual Costs (b)	Ccts	Capital Costs	Annual Costs	Ccts	Capital Costs	Annual Costs	Ccts	Capital Costs	Annual Costs
HVDC													
±400 kV 2 B Chukar	70%	5	\$1577	\$389.9	5	\$1497	\$383.4	5	\$1577	\$337.3	5	\$1497	\$324.3
	90	4	1471	361.4	4	1406	349.1	4	1471	309.7	4	1406	299.5
±400 kV 2 B Thrasher	70	4	1481	379.6	4	1414	366.8	4	1481	321.1	4	1414	310.4
	90	4	1481	348.4	4	1414	335.7	4	1481	297.1	4	1414	286.5
±500 kV 2 B Thrasher	70	3	1414	358.4	3	1363	348.5	3	1414	303.0	3	1363	294.7
	90	3	1414	330.4	3	1363	320.5	3	1414	281.4	3	1363	273.2
±500 kV 3 B Chukar	70	3	1436	351.8	3	1381	341.2	3	1436	296.9	3	1381	288.1
	90	3	1436	327.8	3	1381	317.2	3	1436	278.4	3	1381	269.6
±600 kV 3 B Chukar	70	3	1505	351.9	3	1445	340.1	3	1505	296.3	3	1445	286.5
	90	2	1429	328.8	2	1388	321.0	2	1429	279.6	3	1445	271.8
±600 kV 4 B Chukar	70	2	1447	344.0	2	1403	335.4	2	1447	289.9	2	1403	282.7
	90	2	1447	323.5	2	1403	315.0	2	1447	274.1	2	1403	267.0
±750 kV 6 B Drake	70	2	1895	429.2	2	1845	419.5	2	1895	360.7	2	1845	352.7
	90	2	1895	409.2	2	1845	399.5	2	1895	345.3	2	1845	337.3
±750 kV 6 B Bunting	70	2	1911	422.7	2	1857	412.1	2	1911	354.8	2	1857	346.0
	90	2	1911	406.4	2	1857	395.9	2	1911	342.3	2	1857	333.6
HVAC													
345 kV 1 C Bunting	70%	23	\$1787	\$463.6	23	\$1550	\$418.2	23	\$1787	\$392.6	23	\$1550	\$354.8
	90	23	1787	422.8	23	1550	377.9	23	1787	361.1	23	1550	323.7
345 kV 1 C Chukar	70	19	1803	445.7	19	1561	399.1	19	1803	376.6	19	1561	337.7
	90	19	1803	413.2	19	1561	366.8	19	1803	351.5	19	1561	312.9
500 kV 3 B Bunting	70	8	844	213.0	8	728	190.2	8	844	180.2	8	728	161.3
	90	8	844	198.5	8	728	175.8	8	844	169.1	8	728	150.3
500 kV 3 B Chukar	70	7	871	208.8	7	765	188.0	7	871	176.3	7	765	159.0
	90	7	871	198.0	7	765	176.9	7	871	167.7	7	765	150.4
765 kV 4 B Chukar	70	4	909	209.4	4	823	192.4	4	909	176.3	4	823	162.2
	90	4	909	200.2	4	823	183.2	4	909	169.3	4	823	155.1
765 kV 4 B Thrasher	70	4	960	215.8	4	871	198.2	4	960	181.5	4	871	166.8
	90	4	960	207.8	4	871	190.2	4	960	175.3	4	871	160.7
1100 kV 8 B Chukar	70	3	1423	299.2	3	1279	270.8	3	1423	250.6	3	1279	226.9
	90	3	1423	293.9	3	1279	265.5	3	1423	246.5	3	1279	222.8
1100 kV 8 B Thrasher	70	3	1514	316.1	3	1365	286.6	3	1514	264.6	3	1365	240.0
	90	3	1514	311.1	3	1365	281.7	3	1514	260.8	3	1365	236.2

(a) Ccts = number of circuits.

(b) Minimum annual costs underlined for each load factor.

TABLE 6.12. Capital and Annual Costs--Transmission 500 Miles (millions of dollars)

		18% Annual Cost						15% Annual Cost					
		Terrain II			Terrain I			Terrain II			Terrain I		
Conductor	Load Factor	Ccts (a)	Capital	Annual	Ccts	Capital	Annual	Ccts	Capital	Annual	Ccts	Capital	Annual
			Costs	Costs (b)		Costs	Costs		Costs	Costs		Costs	Costs
HVDC													
±400 kV 2 B Chukar	70%	6	\$2075	\$536.2	6	\$1881	\$499.3	6	\$2075	\$453.9	6	\$1881	\$423.2
	90	5	1920	476.1	5	1759	446.1	5	1920	409.1	5	1759	384.1
±400 kV 2 B Thrasher	70	5	1951	505.6	5	1786	474.0	5	1951	428.0	5	1786	401.7
	90	4	1778	448.8	4	1645	424.1	4	1778	386.2	4	1645	365.7
±500 kV 2 B Thrasher	70	4	1826	461.5	4	1689	435.2	4	1826	390.2	4	1689	368.3
	90	3	1645	412.2	3	1542	392.9	3	1645	354.2	3	1542	338.2
±500 kV 3 B Chukar	70	3	1686	446.2	3	1576	425.3	3	1686	378.0	3	1576	360.6
	90	3	1686	404.2	3	1576	383.4	3	1686	345.6	3	1576	328.3
±600 kV 3 B Chukar	70	3	1771	433.0	3	1651	409.7	3	1771	365.4	3	1651	346.0
	90	2	1619	397.6	3	1651	379.3	2	1619	340.4	3	1651	322.6
±600 kV 4 B Chukar	70	2	1653	418.2	2	1565	401.2	2	1653	353.5	2	1565	339.4
	90	2	1653	384.5	2	1565	367.7	2	1653	327.6	2	1565	313.5
±750 kV 6 B Drake	70	2	2121	503.7	2	2021	484.5	2	2121	424.5	2	2021	408.5
	90	2	2121	471.3	2	2021	452.2	2	2121	399.5	2	2021	383.6
±750 kV 6 B Bunting	70	2	2153	489.5	2	2045	468.6	2	2153	411.6	2	2045	394.2
	90	2	2153	465.3	2	2045	444.5	2	2153	392.9	2	2045	375.5
HVAC													
345 kV 1 C Bunting	70%	23	\$3516	\$898.6	23	\$3043	\$811.6	23	\$3516	\$761.5	23	\$3043	\$689.0
	90	23	3516	804.2	23	3043	718.9	23	3516	687.9	23	3043	616.9
345 kV 1 C Chukar	70	19	3567	868.5	19	3083	778.3	19	3567	733.9	19	3083	658.7
	90	19	3567	793.4	19	3088	704.9	19	3567	676.0	19	3083	601.8
500 kV 3 B Bunting	70	8	1611	403.9	8	1379	359.0	8	1611	341.5	8	1379	304.1
	90	8	1611	373.6	8	1379	329.0	8	1611	318.2	8	1379	281.0
500 kV 3 B Chukar	70	7	1696	402.4	7	1484	361.2	7	1696	339.4	7	1484	305.1
	90	7	1696	378.9	7	1484	337.9	7	1696	321.3	7	1484	287.1
765 kV 4 B Chukar	70	4	1603	366.0	4	1430	332.1	4	1603	307.9	4	1430	279.7
	90	4	1603	349.2	4	1430	315.4	4	1603	295.0	4	1430	266.9
765 kV 4 B Thrasher	70	4	1724	384.0	4	1545	349.0	4	1724	322.7	4	1545	293.5
	90	4	1724	369.3	4	1545	334.4	4	1724	311.3	4	1545	282.2
1100 kV 8 B Chukar	70	3	2730	567.0	3	2441	510.2	3	2730	474.3	3	2441	427.1
	90	3	2730	557.4	3	2441	500.8	3	2730	467.0	3	2441	419.8
1100 kV 8 B Thrasher	70	3	2910	600.5	3	2611	541.7	3	2910	502.2	3	2611	453.2
	90	3	2910	591.7	3	2611	533.0	3	2910	495.4	3	2611	446.5

(a) Ccts = Number of circuits.

(b) Minimum annual costs underlined for each load factor.

TABLE 6.13. Capital and Annual Costs--Transmission 750 Miles (millions of dollars)

Conductor	Load Factor	18% Annual Cost						15% Annual Cost					
		Terrain II			Terrain I			Terrain II			Terrain I		
		Ccts (a)	Capital	Annual	Ccts	Capital	Annual	Ccts	Capital	Annual	Ccts	Capital	Annual
			Costs	Costs (b)		Costs	Costs		Costs	Costs		Costs	Costs
HVDC													
±500 kV 2 B Thrasher	70%	4	\$2120	\$561.2	4	\$1915	\$522.4	4	\$2120	\$475.7	4	\$1915	\$443.3
	90	3	1883	501.3	4	1915	467.1	4	2120	432.6	4	1915	400.6
±500 kV 3 B Chukar	70	3	1939	547.2	4	1993	514.0	3	1939	465.1	4	1993	435.1
	90	3	1939	483.5	3	1775	453.1	3	1939	415.8	3	1775	390.4
±600 kV 3 B Chukar	70	3	2039	516.2	3	1858	481.7	3	2039	436.6	3	1858	407.8
	90	3	2039	471.5	3	1858	438.5	3	2039	403.0	3	1858	374.4
±600 kV 4 B Chukar	70	2	1861	495.7	2	1729	470.6	2	1861	420.2	3	1935	397.8
	90	2	1861	447.1	2	1729	422.2	2	1861	382.6	2	1729	361.9
±750 kV 6 B Drake	70	2	2349	580.8	2	2199	552.4	2	2349	490.7	2	2199	477.0
	90	2	2349	534.5	2	2199	506.3	2	2349	454.9	2	2199	431.4
±750 kV 6 B Bunting	70	2	2395	557.2	2	2233	526.1	2	2395	469.2	2	2233	443.2
	90	2	2395	524.4	2	2233	493.4	2	2395	443.9	2	2233	418.0
HVAC													
500 kV 3 B Bunting	70	8	\$2414	599.1	8	\$2066	\$532.7	8	\$2414	\$506.5	8	\$2066	\$451.2
	90	8	2414	551.2	8	2066	485.5	8	2414	469.4	8	2066	414.6
500 kV 3 B Chukar	70	7	2557	600.5	7	2239	539.4	7	2557	506.2	7	2239	455.3
	90	7	2557	563.4	7	2239	502.8	7	2557	477.5	7	2239	427.0
765 kV 4 B Chukar	70	4	2306	523.4	4	2046	472.9	4	2306	440.3	4	2046	398.2
	90	4	2306	498.2	4	2046	448.0	4	2306	420.8	4	2046	379.0
765 kV 4 B Thrasher	70	4	2501	553.6	4	2233	501.4	4	2501	465.1	4	2233	421.5
	90	4	2501	531.5	4	2233	479.4	4	2501	447.9	4	2233	404.6
1100 kV 8 B Chukar	70	3	3978	821.8	3	3545	737.0	3	3978	687.4	3	3545	616.7
	90	3	3978	807.6	3	3545	723.0	3	3978	676.4	3	3545	605.9
1100 kV 8 B Thrasher	70	3	4247	871.8	3	3798	783.9	3	4247	728.9	3	3798	655.6
	90	3	4247	858.8	3	3798	771.1	3	4247	718.8	3	3798	645.7

(a) Ccts = Number of circuits.

(b) Minimum annual costs underlined for each load factor.

TABLE 6.14. Capital and Annual Costs--Transmission 1000 Miles (millions of dollars)

		18% Annual Cost						15% Annual Cost					
		Terrain II			Terrain I			Terrain II			Terrain I		
Conductor	Load Factor	Ccts ^(a)	Capital	Annual	Ccts	Capital	Annual	Ccts	Capital	Annual	Ccts	Capital	Annual
			Costs	Costs ^(b)		Costs	Costs		Costs	Costs		Costs	Costs
HVDC													
±500 kV 2 B Thrasher	70%	4	\$2418	\$ 665.7	4	\$2144	\$ 614.7	4	\$2418	\$565.4	4	\$2144	\$533.0
	90	4	2418	588.4	4	2144	538.3	4	2418	505.5	4	2144	463.7
±500 kV 3 B Chukar	70	4	2538	653.6	4	2246	598.6	4	2538	553.4	4	2246	507.6
	90	3	2197	566.0	3	1978	526.6	3	2197	489.3	3	1978	456.4
±600 kV 3 B Chukar	70	3	2307	601.2	3	2067	555.7	3	2307	509.2	3	2067	471.3
	80	3	2307	573.5	3	2067	528.2	3	2307	487.8	3	2067	450.1
	90	3	2307	543.1	3	2067	498.1	3	2307	464.2	3	2067	426.8
±600 kV 4 B Chukar	70	2	2071	576.7	3	2168	539.0	2	2071	489.9	3	2168	455.4
	80	2	2071	545.2	2	1895	512.4	2	2071	465.5	2	1895	438.1
	90	2	2071	510.6	2	1895	478.1	2	2071	438.8	2	1895	411.6
±750 kV 6 B Drake	70	2	2579	660.2	2	2380	622.8	2	2579	558.9	2	2380	527.6
	80	2	2579	630.5	2	2380	593.3	2	2579	535.8	2	2380	504.8
	90	2	2579	598.0	2	2380	561.0	2	2579	510.7	2	2380	479.8
±750 kV 6 B Bunting	70	2	2638	625.2	2	2422	583.9	2	2638	527.0	2	2422	492.6
	80	2	2638	605.1	2	2422	564.0	2	2638	511.5	2	2422	477.2
	90	2	2638	583.0	2	2422	542.0	2	2638	494.4	2	2422	460.3
HVAC													
500 kV 3 B Bunting	70	8	\$3167	\$ 782.2	8	\$2703	\$ 695.0	8	\$3167	\$661.4	8	\$2703	\$588.8
	90	8	3167	714.6	8	2703	628.6	8	3167	609.0	8	2703	537.3
500 kV 3 B Chukar	70	7	3362	785.5	7	2938	704.9	7	3362	662.2	7	2938	595.0
	80	7	3362	760.6	7	2938	680.4	7	3362	642.9	7	2938	576.0
	90	7	3362	733.4	7	2938	653.6	7	3362	621.7	7	2938	555.2
765 kV 4 B Chukar	70	4	2953	668.4	4	2606	601.5	4	2953	562.3	4	2606	506.6
	80	4	2953	652.2	4	2606	585.5	4	2953	549.7	4	2606	494.2
	90	4	2953	634.3	4	2606	567.9	4	2953	535.9	4	2606	480.6
765 kV 4 B Thrasher	70	4	3218	710.2	4	2860	640.9	4	3218	596.6	4	2860	538.8
	80	4	3218	695.8	4	2860	626.7	4	3218	585.4	4	2860	527.9
	90	4	3218	680.0	4	2860	611.1	4	3218	573.2	4	2860	515.8
1100 kV 8 B Chukar	70	3	5235	1076.7	3	4658	964.0	3	5235	900.5	3	4658	806.5
	80	3	5235	1067.6	3	4658	955.0	3	5235	893.3	3	4658	799.5
	90	3	5235	1057.5	3	4658	945.1	3	5235	885.5	3	4658	791.8
1100 kV 8 B Thrasher	70	3	5594	1143.8	3	4997	1026.9	3	5594	956.1	3	4997	858.7
	80	3	5594	1135.4	3	4997	1018.7	3	5594	949.5	3	4997	852.3
	90	3	5594	1126.1	3	4997	1009.6	3	5594	942.3	3	4997	845.2

(a) Ccts = Number of circuits.

(b) Minimum annual costs underlined for each load factor.

TABLE 6.15. Least Annual Cost Transmission--10,000 MW at 90% Load Factor
(millions of dollars except as noted)

Miles	HVDC Conductor	Bipole Ccts	Terrain	Capital Required				18%		15%	
				Rectifier	Inverter	Line	Total	Annual Cost	¢/kWh	Annual Cost	¢/kWh
250	600 kV 4 B Chukar	2	II	\$635	\$619	\$ 193	\$1447	\$323.5	0.41	\$274.1	0.35
	600 kV 4 B Chukar	2	I	635	619	149	1403	315.0	0.40	267.0	0.34
500	600 kV 4 B Chukar	2	II	648	619	386	1653	384.5	0.49	327.6	0.42
	600 kV 4 B Chukar	2	I	648	619	298	1565	367.7	0.47	313.5	0.40
750	600 kV 4 B Chukar	2	II	663	619	579	1861	447.1	0.57	382.6	0.49
	600 kV 4 B Chukar	2	I	663	619	447	1729	422.2	0.54	361.9	0.46
1000	600 kV 4 B Chukar	2	II	680	619	772	2071	510.6	0.65	438.8	0.56
	600 kV 4 B Chukar	2	I	680	619	596	1895	478.1	0.61	411.6	0.52
Stations											
	HVAC	Ccts		Structs. & Equipment Compensation Line			Total				
250	500 kV 3 B Chukar	7	II	\$ 84	\$117	\$ 670	\$ 871	\$198.0	0.25	\$167.7	0.21
	500 kV 3 B Bunting	8	I	96	100	532	728	175.8	0.22	150.3	0.19
500	765 kV 4 B Chukar	4	II	276	270	1057	1603	349.2	0.44	295.0	0.37
	765 kV 4 B Chukar	4	I	276	270	884	1430	315.4	0.40	266.9	0.34
750	765 kV 4 B Chukar	4	II	307	413	1586	2306	498.2	0.63	420.8	0.53
	765 kV 4 B Chukar	4	I	307	413	1326	2046	448.0	0.57	379.0	0.48
1100	765 kV 4 B Chukar	4	II	314	525	2114	2953	634.3	0.80	535.9	0.68
	765 kV 4 B Chukar	4	I	314	525	1767	2606	567.9	0.72	480.6	0.61

TABLE 6.16. Annual Cost of Losses [for least annual cost transmission - transmit 10,000 MW at 90% load factor (millions of dollars)]

Miles	HVDC Conductor	Ccts	Terrain	Losses	Annual Loss Costs	
					18%	15%
<u>250</u>	±600 kV 4 B Chukar	2	II	452 MW	\$ 35.1	\$33.4
	±600 kV 4 B Chukar	2	I	452	35.3	33.6
<u>500</u>	±600 kV 4 B Chukar	2	II	741	55.3	52.8
	±600 kV 4 B Chukar	2	I	741	55.9	53.3
<u>750</u>	±600 kV 4 B Chukar	2	II	1069	76.2	73.2
	±600 kV 4 B Chukar	2	I	1069	77.5	74.2
<u>1000</u>	±600 kV 4 B Chukar	2	II	1448	98.2	94.6
	±600 kV 4 B Chukar	2	I	1448	100.5	96.2
HVAC						
<u>250</u>	500 kV 3 B Chukar	7	II	253 MW	\$ 21.2	\$20.0
	500 kV 3 B Bunting	8	I	327	27.7	26.1
<u>500</u>	765 kV 4 B Chukar	4	II	369	28.2	27.0
	765 kV 4 B Chukar	4	I	369	28.8	27.5
<u>750</u>	765 kV 4 B Chukar	4	II	539	37.4	36.2
	765 kV 4 B Chukar	4	I	539	38.7	37.2
<u>1000</u>	765 kV 4 B Chukar	4	II	713	44.8	43.9
	765 kV 4 B Chukar	4	I	713	47.1	45.7

forested or remote areas where development of access roads is not practical, a clearing for an aircraft landing area may be needed for construction and later for maintenance purposes.

Land requirements for both AC and DC transmission lines of various voltage ratings depend on the right-of-way width, which generally increases with line voltage. However, fewer lines are required to transmit a given amount of power as the voltage is increased. Right-of-way widths vary according to type of transmission (AC or DC), line voltage, and configuration of the conductors. A set of typical right-of-way requirements for various voltage levels and conductor configurations is presented in Table 6.17. The land cost estimates of this report are based on requirements of 12 to 24 acres per mile over the voltage range.

TABLE 6.17. Right-of-Way (ROW) Requirements

<u>Voltage and Type (kV)</u>	<u>Circuit Configuration</u>	<u>ROW Width (ft)</u>	<u>ROW Land Requirement (acres/mile)</u>
345 AC	Single circuit	90	11
500 AC	Single circuit, flat	115	14
765 AC	Single circuit	130	16
1100 AC	Single circuit Delta	200	24
±400 DC	Single circuit	115	14
±600 DC	Single circuit	120	15
±800 DC	Single circuit	125	15
±800 DC	Single circuit, flat	155	19

Right-of-way widths are generally based on the levels of audible noise, radio interference and electric field strength on the edge of the right-of-way. These constraints are presented in Table 6.18.

Land use is limited in the right-of-way because residences and other structures generally are not allowed. In most cases, however, the right-of-way

TABLE 6.18. Line Design Constraints^(a)

<u>Criterion</u>	<u>AC Lines</u>	<u>DC Lines</u>
Audible noise at edge of ROW	55 dbA ^(b)	45-50 dbA ^(c)
Radio interference at edge of right-of-way	50-55 dB ^(d)	53-58 dB ^(d)
Electric field	2 kV/m	(e)

(a) Source: Commonwealth Associates, Inc. (1978).

(b) Not to be exceeded more than 50% of the time in rain.

(c) Not to be exceeded more than 50% of the time in fair weather.

(d) Not to be exceeded more than 20% of the time.

(e) The methods of interaction between HVAC and HVDC and biological systems are quite different. Interference criteria for HVDC lines have not been established.

may be used for farming or other activities not requiring structures and otherwise compatible with transmission. The land occupied by the tower base is, of course, not available for other use. About 0.04 acre per base is required (Commonwealth Associates, Inc. 1979). Considerable disagreement exists concerning the right-of-way width requirements for high voltage transmission lines. This controversy focuses on several issues, including ozone production, possible effects on cardiac pacemakers, audible noise, and biological effects of magnetic and electrical fields.

In addition to right-of-way requirements, land will be required for AC terminals, intermediate stations and DC converter stations. Substations may require from 2 to 50 acres, depending primarily on the voltage and the number of lines served (Commonwealth Associates, Inc. 1979). Progress has been made in reducing the land required for DC converter stations since the construction of the Pacific Intertie using mercury-arc valves. The introduction of semiconductor thyristor valves has considerably reduced land requirements for air-insulated converter stations. Present investigations of gas-insulated compact designs are expected to lead to a further three-fold reduction. Reduction in land requirements is illustrated in Table 6.19.

6.7.2 Construction Manpower

The manpower required for constructing an electric power transmission system depends upon construction time, voltage and capacity. The construction of its system involves technical and administrative personnel (e.g., engineers,

TABLE 6.19. Estimated Land Requirements for DC Converter Stations

<u>Station</u>	<u>Size (ft)</u>	<u>Land Area (acres)</u>
Celilo (Pacific Intertie)- 1440 MW, Mercury Arc	1066 x 865	21.1
2000 MW air insulated, thyristor	1050 x 560	13.5
2000 MW air insulated, compact	400 x 144	1.3
2000 MW gas insulated, compact	300 x 50	0.3

designers, draftsmen, clerks), and skilled manual labor (e.g., ironworkers, electricians, linesman) for approximately 2 years.

The personnel required for line design and construction are roughly estimated in Table 6.20. Operating manpower requirements are discussed in Section 6.6.1.

6.7.3 Major Materials

The principal material requirements for transmission systems include structural steel for towers, steel and aluminum for conductors, steel for shield wire and foundation reinforcing, insulators, insulator and conductor hardware, and concrete. The use of higher voltages reduces these material requirements because the greater load-carrying capacity of higher-voltage systems allows fewer lines for a total given capacity. This material reduction is somewhat offset by the greater tower size required for adequate conductor separation. Direct current systems require less conductor steel and aluminum compared to equivalent AC systems because of the use of two conductors rather than three per circuit. The structural and insulation requirements for AC and DC transmission lines at various voltages are presented in Table 6.21. Conductor material requirements for various conductor types are shown in Table 6.22.

For transmission systems about 1000 miles long, AC substation and DC converter station material requirements are small compared to those of the transmission lines. The primary material requirements of a DC converter station are aluminum, steel, copper, insulating oil, and concrete. The material requirements of a 500 MW DC converter station are presented in Table 6.23. An AC substation of equivalent power capacity has a smaller total material requirement.

TABLE 6.20. Personnel Requirements for Transmission Line Design and Construction

<u>Line Data</u>	<u>Technical and Administrative</u>		<u>Crafts and Labor</u>
	<u>1st Year</u>	<u>2nd Year</u>	<u>Peak</u>
345 kV, 500 miles	230	160	930
500 kV, 500 miles	350	250	1250

TABLE 6.21. Major Material Requirements for Various Transmission System Configurations

<u>Configuration</u>	<u>Steel (ton/mile)</u>	<u>Insulators^(a) (ton/mile)</u>	<u>Hardware^(a) (ton/mile)</u>	<u>Concrete^(a) (yd³/mile)</u>
345 kV single circuit	80	5	1	70
500 kV AC double circuit	160	10	1	70
765 kV AC single circuit	120	10	2	80
765 kV AC double circuit	300	20	4	80
1100 kV AC single circuit	420	25	3	200
±400 kV DC	40	6	1	70
±500 kV DC	60	7	1	80
±600 kV DC	80	8	2	90
±750 kV DC	100	15	3	130

Source: Commonwealth Associates, Inc. (1978).

TABLE 6.22. Weights of Typical Conductors

<u>Conductor Type</u>	<u>Steel (ton/mile)</u>	<u>Aluminum (ton/mile)</u>	<u>Total (ton/mile)</u>
Drake	0.8	2.1	2.9
Bunting	0.5	3.1	3.6
Chukar	0.8	4.7	5.5
Thrasher	0.7	6.0	6.7

Source: Arthur D. Little, Inc. (1979).

Although the capacity of the 500 MW DC station is only 2.5% of the total that would be required at both ends of the transmission system studied here, the order-of-magnitude and the relative amounts of different material requirements can be deduced.

TABLE 6.23. Material Requirements of a
500 MW DC Converter Station

<u>Material</u>	<u>Amount (tons)</u>
Aluminum	62
Steel (all types)	1050
Copper	92
Insulating oil	500
Mylar	77
Concrete	2800

Source: Arthur D. Little (1979).

6.8 ENVIRONMENTAL EFFECTS

The potential environmental effects of electric power transmission may be examined in three main categories: effects of construction and maintenance, radiation and chemical effect of corona, and effects of electric and magnetic fields.

6.8.1 Construction and Maintenance

The environmental effects of construction and maintenance of transmission lines vary widely according to the terrain. The effects include clearing of the land within the right-of-way, and for access roads, soil compaction and other physical damage during construction, interference with agriculture and other land uses by tower structures, and the aesthetic or visual impact of towers and lines.

Habitat modification resulting from right-of-way clearing may benefit certain animal species that are able to adapt to a transitional or fringe habitat. Other species which are more sensitive to destruction of their habitat or which exhibit little tolerance to human activity may, in effect, be eliminated by activities in the right-of-way. The effects of clearing the right-of-way on indigenous animal populations are entirely site-specific.

In some cases, removing vegetation for clearing right-of-way corridors or constructing access roads may create an erosion problem. In forested areas,

transmission line construction starts as a logging operation that may leave long-lasting visible effects. In addition, the air quality, water quality, microclimate, and soil productivity may be affected.

A common complaint against high-voltage transmission lines is their visual or aesthetic impact, especially in scenic and recreational areas. Visual impacts depend on the type of transmission tower (design, color, size, bulk and height), width of the right-of-way corridor, type of landscape setting, and viewing distance, but these may be modified by the degree of visibility and the setting.

Electric utilities reduce the visual impacts of substations and transmission lines by attention to route selection, placement of towers, judicious right-of-way clearing and landscaping, more pleasing tower designs, and the use of materials and colors to blend with the surroundings.

6.8.2 Corona

Corona is a discharge of high-voltage electricity into the immediate space around conductors and other line components. It produces several effects, including interference with radio and television reception, the generation of audible noise, and the production of ozone and nitrogen oxides. In good weather, corona discharge is very small; it is primarily a foul weather problem. Dust, insects, leaf material and other particles clinging to transmission lines are the major causes of corona, although heavy rain and snow cause a significant increase in corona.

Induced currents and radiated electromagnetic fields generated by corona create radio and television interference. The intensity of the interference depends on the distance from the transmission line to the receiver, the transmission line geometry, line voltage and weather conditions (NRC 1977). High-voltage transmission lines that operate without corona are impractical. Each line should be designed and the transmission corridor planned to minimize interference and achieve tolerable noise levels in the area. Interference criteria at the edge of the right-of-way for AC lines generally range from 50 to 55 dB and from 53 to 58 dB for DC lines (Commonwealth Associates, Inc. 1979).

Audible noise from transmission lines is most often a foul weather phenomenon and is generally characterized by a crackling or hissing and a low-level hum. The possible effects from corona noise include interference with sleep, speech interference, general annoyance, and increased tension or fatigue.

Corona also produces small amounts of ozone and nitrogen oxides. Ambient concentrations in rural areas usually range from 0.01 to 0.06 ppm, but concentrations exceeding 0.1 ppm are not uncommon. The amounts of ozone and nitrogen oxides produced by transmission lines operating at 345 kV and higher are so low that they are not detectable above ambient concentrations (DOE 1979, 1980b). For example, two 500 kV transmission lines are expected to increase ozone concentrations 0.006 to 0.0012 ppm above ambient during foul weather (Lee et al. 1978).

In general, the corona effects from a DC transmission line are less than those from an AC line. Radio and television interference and audible noise from a DC line change little in foul weather and actually may decrease slightly. The amount of ozone produced by a DC line appears to be roughly the same as the small quantity produced by an AC line of equivalent voltage.

6.8.3 Electric and Magnetic Fields

The effects of electric and magnetic fields include hazard of electric shock due to contact with lines, induced electric currents and voltages, the small risks of fuel ignition by spark discharges and interference with obsolete cardiac pacemakers, and possible biological effects of these fields. Electric and magnetic fields in the vicinity of transmission lines induce voltages and currents in nearby conducting objects. In properly designed transmission lines, the shock that a person can receive from contact with a nearby conducting object is well below the level that can cause harm (ITT Research Institute 1979) and may be little more than annoying.

The possible biological effects of electric and magnetic fields are highly controversial. Several studies are currently in progress. Biological responses to electric and magnetic fields have been detected in some animal subjects and are under continuing investigation.

The State of New York Public Service Commission's decision to increase the right-of-way for a proposed 765 kV transmission line from 250 to 350 feet was based primarily on unanswered questions concerning electric and magnetic fields. Following extensive testimony, the Commission concluded that several unresolved questions cannot be ignored. Consequently, the right-of-way was expanded so that the field strength and its edge were no greater than that produced by existing 345 kV lines at the edge of their right-of-way (State of New York Public Service Commission 1978). This electric field strength (assuming a single circuit line and a 150-foot right-of-way) is about 1.6 kV/m. Typically, the maximum levels of electric fields generated by a 500 kV transmission line are 8 kV/m on the ground under the line (35 feet ground-to-conductor clearance) and 2.5 to 3.5 kV/m at the edge of the right-of-way (Lee et al. 1978). An 1100/1200 kV line with a 76-foot ground-to-conductor clearance would have an electric field of 6 kV/m directly under the line.

The biological interactions of the electric field of a DC line are fundamentally different from those of an AC line. Equal field magnitudes do not create similar effects, and shock tolerance levels are much higher for DC than they are for AC. Clarifying these complexities is the prime objective of at least three major research programs into the bioeffects of electric power transmission lines. Eventually, the progress now being made will allow lines to be designed and constructed with even less impact than those of today.

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APPENDIX A

REVIEW OF FEDERAL AIR-QUALITY REGULATIONS

APPENDIX A

REVIEW OF FEDERAL AIR-QUALITY REGULATIONS

This appendix reviews the major federal air-quality regulations affecting construction and operation of coal-fired power plants. The three main regulations are the New Source Performance Standards, State Implementation Plan, and Prevention of Significant Deterioration, which are described below.

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The NSPS consists of emission limits for SO_2 , NO_x , and particulates for all new electric generating plants in the U.S. The standards are based on pounds of pollutant per million Btu input and are summarized in Table A.1. Eastern utilities became very interested in Western coal since 80% of all coals in the U.S. with sulfur content below 0.6% can meet existing NSPS standards for SO_2 without any scrubbing. However, the proposed standards will require some level of scrubbing on all coal-fired plants.

The level of SO_2 removal needed to comply with the proposed NSPS will vary depending on the heat value and sulfur content of the coal being burned. Coal may be classified into three categories described below (Allen and Kaslow 1979).

- Category 1 Coals with uncontrolled SO_2 emissions that are equal to or less than $2 \text{ lb}/10^6 \text{ Btu}$ must remove 70% of potential SO_2 emissions.
- Category 2 Coals with uncontrolled SO_2 emissions between $2 \text{ lb}/10^6 \text{ Btu}$ and $6 \text{ lb}/10^6 \text{ Btu}$ must limit SO_2 emissions to $6 \text{ lb}/10^6 \text{ Btu}$. Therefore, the percent removal required for coals in this category will vary depending on their potential uncontrolled emissions.
- Category 3 Coals with uncontrolled SO_2 emissions between $6 \text{ lb}/10^6 \text{ Btu}$ and $12 \text{ lb}/10^6 \text{ Btu}$ must remove 90% of potential SO_2 emissions.

TABLE A.1. New Source Performance Standards

<u>Existing^(a)</u>	<u>Emissions Ceiling</u>	<u>Required Reduction of Uncontrolled Emissions</u>
Particulates	0.1 lb/10 ⁶ Btu	No Reduction
NO _x	0.7 lb/10 ⁶ Btu	No Reduction
SO ₂	1.2 lb/10 ⁶ Btu	No Reduction
<u>Proposed^(b)</u>		
Particulates	0.03 lb/10 ⁶ Btu	99% Reduction
NO _x		
- Subbituminous Coal	0.5 lb/10 ⁶ Btu	65% Reduction
- Bituminous Coal	0.6 lb/10 ⁶ Btu	65% Reduction
- Northern Great Plains Lignite Burned in Slag Tap Furnaces	0.8 lb/10 ⁶ Btu	No Reduction
	<u>Potential SO₂ Emissions</u>	
SO ₂	0 - 2 lb/10 ⁶ Btu	70% Reduction
	2 - 6 lb/10 ⁶ Btu	70-90% Reduction
	6 - 12 lb/10 ⁶ Btu	90% Reduction

If potential SO₂ emissions exceed 12 lb/10⁶ Btu, the coal may only be burned if emissions do not exceed 1.2 lb/10⁶ Btu.

(a) 40 CFR 60.42-45.

(b) Environment Reporter, June 30, 1978 and Allen and Kaslow, 1979.

The absolute upper limit for all coals is 1.2 lb/10⁶ Btu. Therefore, coals with potential SO₂ emission above 12 lb/10⁶ Btu may not be burned unless SO₂ removal exceeds 90% and the 1.2 lb/10⁶ Btu limit is met.

Compliance with the proposed NSPS will be determined on a 30-day rolling average.

The proposed 0.03 lb/10⁶ Btu NSPS for particulate emissions, although stringent, is not a major problem for most utilities since electrostatic precipitators and other particulate removal systems provide a high removal

efficiency with relatively few problems. SO₂ removal systems, however, have encountered many problems with scaling and plugging.

The existing NSPS for NO_x emissions (0.7 lb/10⁶ Btu) caused many utilities to seek alternate combustion methods since effective NO_x removal systems available for large generating units are quite expensive. Many utilities could meet the existing standards by instituting staged firing techniques in boilers. However, if the EPA decides to further lower the NO_x emissions standards below the proposed NSPS (Table A.1), other methods such as flue gas scrubbing may be necessary.

STATE IMPLEMENTATION PLAN (SIP)

The federal government has established National Ambient Air Quality Standards (NAAQS) which are summarized in Table A.2. The standards are based on ground level concentrations of six pollutants that are measured in micrograms per cubic meter (μg/m³) at a distance from the polluting source. Of the six pollutants listed in Table A.2, only SO₂, NO_x, and particulates cause constraints on power plants. Under the Clean Air Act of 1970, the federal government required the states to establish plans to control emissions so that the NAAQS (especially for the SO₂ standard) would not be violated. These State Implementation Plans (SIP) are superceded by the NSPS whenever the former are less stringent. Table A.3 lists the SIP standards for SO₂ for Wyoming, Montana, Illinois, and Missouri along with the amount of scrubbing required for coals of varying sulfur and heat content.

In addition to the NSPS and SIP regulations, the EPA has identified Air Quality Maintenance Areas (AQMA) having the potential to exceed the secondary NAAQS by 1985 (40 CFR 52.21). Two areas in Wyoming and six areas in Montana have been designated as AQMA and are shown in Figure A.1, and their potential pollutants given in Table A.4. Four areas in Illinois and Missouri have been designated AQMA and are shown in Figure A.2 and their potential pollutants given in Table A.5. The statistics are required to develop strategies for these areas that will insure that the NAAQS for the specified potential pollutant will not be exceeded with increasing regional growth and growth and development. The AQMA plans are included in the SIPs of the appropriate state.

TABLE A.2. National Ambient Air-Quality Standards^(a)

Pollutant	Standard ($\mu\text{g}/\text{m}^3$)	
	Primary ^(b)	Secondary ^(c)
Particulate		
Annual Geometric Mean	75	60
24-Hour Maximum ^(d)	260	150
Sulfur Oxides (SO_2)		
Annual Mean	80	-
24-Hour Maximum	365	-
3-Hour Maximum	-	1300
Photochemical Oxidant		
1-Hour Maximum	160	160
Hydrocarbons		
3-Hour Maximum (6-9 AM)	160	160
Nitrogen Oxide (NO_2)		
Annual Mean	100	100
Carbon Monoxide		
8-Hour Maximum	10 mg/m^3	10 mg/m^3
1-Hour Maximum	40 mg/m^3	40 mg/m^3

(a) 40 CFR 50.4-11.

(b) Primary standards are designed to provide an adequate margin of safety to protect the public health.

(c) Secondary standards are designed to protect the public welfare from the known or anticipated adverse effects associated with the presence of such air pollutants in the ambient air.

(d) Exceeded <1 time/year.

In addition to the AQMAs, the EPA has designated Air Quality Control Regions (AQCR) for all parts of the U.S. as a means of monitoring and regulating air quality on a local level. These regions are usually comprised of adjacent counties that have similar pollution characteristics. Figures A.3 and A.4 show the AQCRs for Wyoming/Montana and Missouri/Illinois. In the 1977 Amendment of the Clean Air Act, the EPA, after consultation with state authorities, classified each AQCR as priority IA, I, II, and III (Table A.6). The classifications reflect the actual or estimated existing pollution levels for five pollutants in each region that were developed by the EPA "for purposes of plan development and evaluation (40 CFR 51.3). The classification of AQCRs for Wyoming/Montana and Illinois/Missouri is listed in Tables A.7 and A.8.

TABLE A.3. SO₂ Control Requirements for Selected State Implementation Plans

	<u>Sulfur Content</u>	<u>Btu Content</u>	<u>% Scrubbing</u>
Wyoming:	0.5	9,667	80
0.2 lb/10 ⁶ Btu	0.5	10,453	78
(New Sources)	0.6	11,489	80
	0.7	12,728	81
	1.0	9,760	90
Montana:	0.5	9,667	0
1.0 lb/10 ⁶ Btu	0.5	10,453	0
(All Sources)	0.6	11,489	0
	0.7	12,728	0.4
	1.0	9,760	51
Illinois:	0.5	9,667	-
1.2 lb/10 ⁶ Btu	0.6	11,489	-
(New Sources)	0.7	12,728	-
	1.0	9,760	38
Missouri:			
1000 lb SO ₂ /hr for			
Selected Sources			
St. Louis	Limit of 2.3% Sulfur in Coal		

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The EPA has established Prevention of Significant Deterioration classifications for AQCRs that meet the secondary NAAQS (40 CFR 52.21). The PSD standards were designed to prevent areas with very low pollutant levels from being polluted up to the secondary NAAQS. Under the PSD regulation, all "attainment" areas that meet the secondary NAAQS are classified as follows:

- Class I: Pristine areas, little or no industrial development allowed
- Class II: Moderate, well-controlled development allowed
- Class III: Concentrated industrial development but not exceeding NAAQS.

Table A.9 lists the allowable pollution increments over baseline air quality that are specified in the 1977 Amendments to the Clean Air Act. Baseline air quality is determined from data provided by the EPA or a state air pollution control agency. The designation of PSD classes for AQCRs or their subdivision is to be determined by the states and included in the State Implementation Plans within the guidelines set fourth by the 1977 amendments.

FIGURE A.1. Wyoming and Montana Air-Quality Maintenance Area Map

Originally, all AQCRs were classified as Class II except for the Northern Cheyenne Indian Reservation in Montana which was subsequently redesigned as Class I. With the passage of the 1977 amendments, the following areas were immediately designated as Class I areas (Environment Reporter November 11, 1977):

TABLE A.4. Wyoming and Montana Air-Quality Maintenance Areas^(a)

Area	Potential Pollutant					Map Region/Counties	
	Particulate Matter	Sulfur Oxides	Nitrogen Oxides	Carbon Monoxide	Photochemical Oxidants		
Kalispell	X					A	Flathead Lake
Missoula	X			X		B	Missoula
Helena		X				C	Lewis and Clark
Anaconda-Butte	X	X				D	Deer Lodge Silver Bow
Billings	X	X		X		E	Stillwater Sweet Grass Yellowstone Big Horn (Excluding Northern Cheyenne Indian Reservation)
Southern Montana Coal Resource	X	X				F	Carter Custer Fallon Powder River Rosebud Treasure Northern Cheyenne Indian Reservation
Sweetwater	X	X				G	Sweetwater
Powder River Basin	X				X	H	Cambell Converse

(a) 40 CFR 52.2631 and 40 CFR 52.1381.

FIGURE A.2. Illinois and Missouri Air-Quality Maintenance Area Map

- International parks
- National Wilderness areas
- National memorial parks greater than 5,000 acres in size
- National parks greater than 6,000 acres in size
- All areas previously designated as Class 1.

The Class I areas for Wyoming and Montana are shown in Figure A.5. There are currently no Class I areas in Illinois and Missouri.

TABLE A.5. Illinois and Missouri Air-Quality Maintenance Areas^(a)

Area	Potential Pollutant					Map Region/Counties	
	Particulate Matter	Sulfur Oxides	Nitrogen Oxides	Carbon Monoxide	Photochemical Oxidants		
Kansas City Interstate (Missouri Portion)	X					A Cass Clay	Jackson Platte
St. Louis Interstate	X	X			X	B Missouri	Illinois
						St. Louis City St. Louis County Franklin Jefferson St. Charles	Madison Monroe St. Clair
Decatur	X					C Macon	
Peoria	X	X				D Peoria Tazewell	Woodford
Illinois-Indiana-Wisconsin Interstate (Illinois Portion)	X	X	X	X	X	E Cook Dupage Kane	Lake McHenry Will

(a) 40 CFR 52.735 and 40 CFR 52.1338.

FIGURE A.3. Wyoming and Montana Air-Quality Control Region Map

States may redesign any area to Class I. States may also redesign areas to Class III except the following areas greater than 10,000 acres in size:

- Present national monuments
- Primitive areas
- Wild and scenic rivers

FIGURE A.4. Illinois and Missouri Air-Quality Control Region Map

- Lakeshores and seashores
- Future national parks and wilderness areas.

The procedure for redesignating areas to Class III is complicated, requiring public hearings, local approval by affected residents, consultation with the state legislature, and approval by the governor.

TABLE A.6. Air-Quality Control Region Priority Definitions^(a)
(in $\mu\text{g}/\text{m}^3$ (ppm) except where noted)

<u>Pollutant</u>	<u>Priority I Greater Than</u>	<u>Priority II From-To</u>	<u>Priority III Less Than</u>
Sulfur Oxides			
Annual Arithmetic			
Mean	100 (0.04)	60-100 (0.02-0.04)	60 (0.02)
24-hr Maximum	455 (0.17)	260-455 (0.10-0.17)	260 (0.10)
3-hr Maximum	--	1,300 (0.5) - 1,300 (0.5)	1,300 (0.05)
Particulate Matter			
Annual Geometric			
Mean	95	60-95	60
24-hr Maximum	395	150-325	150
Carbon Monoxide			
1-hr Maximum	55 mg (48)	--	55 mg (48)
8-hr Maximum	14 mg (12)	--	14 mg (12)
Nitrogen Dioxide			
Annual Arithmetic			
Mean	110 (0.06)	--	110 (0.06)
Photochemical			
Oxidants			
1-hr Maximum	195 (0.10)	--	195 (0.10)

Priority IA: Where a region is classified Priority I on the basis of measured or estimated air-quality levels reflecting emissions predominantly from a single point source, it shall be further classified Priority IA.

^(a) 40 CRF 51.3.

Areas that currently do not meet the secondary NAAQD are classified as "nonattainment" areas (NA). The SIPs must include plans for NA compliance with the primary NAAQS for SO_2 and particulates by December 31, 1983. An extension of five years is available for meeting primary NAAQS for photochemical oxidants or carbon monoxide.

If the SIPs are not approved by the EPA by June 30, 1979, the EPA is empowered to prohibit major stationary sources from locating in a NA. However,

TABLE A.7. Wyoming and Montana Air-Quality Control Region Classifications^(a)

	<u>Map Region</u>	<u>Particulate Matter</u>	<u>Sulfur Oxides</u>	<u>Nitrogen Dioxide</u>	<u>Carbon Monoxide</u>	<u>Hydro- Carbons</u>
Montana Regions						
Missoula Intrastate	A	I	III	III	III	III
Great Falls Intrastate	B	III	IA	III	III	III
Helena Intrastate	C	IA	IA	III	III	III
Billings Intrastate	D	II	II	III	III	III
Miles City Intrastate	E	III	III	III	III	III
Wyoming Regions						
Wyoming Intrastate	F	III	III	III	III	III
Casper Intrastate	G	II	III	III	III	III
Cheyenne Intrastate	H	II	III	III	III	III

(a) 40 CFR 52 2621 and 40 CFR 52.1371.

industries that submit permits prior to July 1, 1979, may be allowed to locate in NAs even if their SIP has not been approved (Environment Reporter March 2, 1979).

The PSD requirements will have a significant effect on power plant siting. However, a good deal of uncertainty still exists over which areas could accommodate power plants. Virtually all power plants would be excluded from Class I areas and some utilities believe that many Class II areas could not tolerate a 1000 MW plant. When multiple plants are involved, the siting options are still fewer.

TABLE A.8 Illinois and Missouri Air-Quality Control Region Classifications^(a)

<u>Missouri/Illinois Regions</u>	<u>Map Region</u>	<u>Particulate Matter</u>	<u>Sulfur Oxides</u>	<u>Nitrogen Dioxide</u>	<u>Carbon Monoxide</u>	<u>Hydro- Carbons</u>
Metropolitan Dubuque Interstate	A	I	III	III	III	III
Rockford-Janesville- Beloit Interstate	B	II	III	III	III	III
Metropolitan Quad Cities Interstate	C	I	III	III	III	III
North Central Illinois Interstate	D	II	IA	III	III	III
Metropolitan Chicago Interstate	E	I	I	I	I	I
Burlington-Keokuk Interstate	F	I	I	III	III	III
East Central Illinois Interstate	G	III	II	III	III	III
West Central Illinois Interstate	H	I	IA	III	III	III
Metropolitan St. Louis Interstate	I	I	I	III	I	I
Southeast Illinois Intrastate	J	III	II	III	III	III
Paducah-Cairo Interstate	K	I	II	III	III	III
Northern Missouri Intrastate	L	II	III	III	III	III
Metropolitan Kansas City Interstate	M	I	III	III	I	I
Southwest Missouri Intrastate	N	I	III	III	III	III
Southeast Missouri Intrastate	O	III	III	III	III	III

TABLE A.9 Prevention of Significant Deterioration (PSD) Permitted Increments ($\mu\text{g}/\text{m}^3$) (a)

	<u>Class I</u>	<u>Class II</u>	<u>Class III</u>	<u>NAAQS (Primary)</u>	<u>NAAQS (Secondary)</u>
SO ₂ Annual	2	20	40	80	
24-hr	5	91	182	365	
3-hr	25	512	700		1300
TSP(b) Annual	5	19	37	75	60
24-hr	10	37	75	260	150

(a) Environment Reporter November 11, 1977.

(b) Total Suspended Particulates.

Note: 24- and 3-hr standards to be exceeded <1 per year.

One alternative to power plant siting limitations resulting from PSD classifications is the EPA's Emissions Offset Policy (EOP). The EOP will allow new major stationary sources to locate in NAs and some PSDs if the net pollution of the area is decreased. This would mean that developers of a new source must provide pollution control for or eliminate established sources so that the total pollution level of the area is reduced.

The EOP was only applicable until June 30, 1979, when the SIPs were to take effect. The states may adopt the EPA's offset policy into their SIP or use their own plan (Environment Reporter September 15, 1978). In either case the primary NAAQS for SO₂ and particulates must be achieved by December 31, 1982.

In addition to the offset policy is the bubble concept. Here, the entire plant would be treated as a point source and may expand if the total plant emissions (including the new unit) are less than the emissions from the original source (Environment Reporter March 2, 1979).

The PSD regulations will affect power plant siting and costs in four ways. First, large power plants will be restricted from locating in Class I areas and possibly other areas depending on a state's implementation plan.

FIGURE A.5. Class I Areas for Wyoming and Montana

Second, sources locating adjacent to Class I areas may also be restricted if they affect the air quality in the Class I area. Third, multiple power plant sitings could be limited, restricting minemouth power generation in coal-producing AQCRs. Fourth, with limited budgets in many states, the process for

obtaining PSD permits may be time consuming and cause increase in lead time for power plants. One article estimated that a PSD permit could take up to 43 months to obtain (Hoffnagle and Dunlap 1979).

It is felt that many SIPs will adopt some form of the EPA Emission Offset Policy, although they are not required to. This will mean that utilities that are planning power plants in nonattainment areas (and in some cases PSDs) will have the option of paying for pollution control equipment on established sources or buying out and shutting down other sources so that the net pollution of the area is decreased.

The total effect of the PSD regulations will not be known until the SIPs are submitted and approved by the EPA. Even then, new sources will be evaluated on a case-by-case basis. It seems apparent though, that of all the air quality regulations the PSD requirements will have the greatest impact on power plant siting.

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APPENDIX B

AN ALTERNATIVE METHOD FOR COMPUTING OPERATING AND MAINTENANCE COST ESTIMATES FOR A COAL-FIRED POWER PLANT

APPENDIX B

AN ALTERNATIVE METHOD FOR COMPUTING OPERATING AND MAINTENANCE COST ESTIMATES FOR A COAL-FIRED POWER PLANT

This appendix includes a methodology for computing operating and maintenance cost estimates based on a number of plant design parameters as well as empirically derived relationships of O&M costs components. The methodology was developed by United Engineers and Constructors (UE&C) in Commercial Electric Power Cost Studies, Part 8--Total Generating Costs: Coal and Nuclear Plants (1979). We have expanded some of the equations slightly for clarity, although the basic relationships have not been altered. The methodology is explained below and an example calculation follows.

For coal-fired plants, UE&C has identified six general categories of O&M costs for the purpose of estimating these charges:

- plant staff
- fixed maintenance materials
- variable maintenance materials
- fixed supplies and expenses
- variable supplies and expenses
- administrative and general expenses.

Generic relationships are used to estimate the above categories. In some cases, O&M costs for SO₂ removal and cooling are broken out separately since these systems use interchangeable technologies that have different costs.

The equations below are based on empirically derived factors based on historical operation of coal-fired plants.

Annual Operating Staff Cost:

$$\text{STAFF COST } t_i = \text{TOTSTAFF}_{t_b} + \text{TOTSTAFFS}_{t_b} (1 + e)^{t_i - t_b} \quad (\text{B.1})$$

where

STAFF COST t_i = Total annual staff cost in year i (\$)
 TOTSTAFF $_{t_b}$ = Total annual cost of station (excluding FGD) staffing members at base year (\$)
 TOTSTAFFS $_{t_b}$ = Total annual cost of station staffing members for SO₂ removal in base year (\$)
 e = Annual rate of aggregate escalation.
 TOTSTAFF $_{t_b}$ = NMAN (SALARY $_{t_b}$)
 TOTSTAFFS $_{t_b}$ = NMANS (SALARY $_{t_b}$)

where

NMAN = Number of staff for station (excluding FGD equipment) (Table B.1)
 NMANS = Number of staff for SO₂ removal (Table B.1)
 SALARY $_{t_b}$ = Annual average cost of staffing member at base year (\$).

Fixed Maintenance Material Cost:

$$\text{FIXMAIN}_{t_i} = (\text{FIXFAC})(\text{PERTMC})(\text{TOTSTAFF}_{t_b})(1 + e)^{t_i - t_b} \quad (\text{B.2})$$

where

FIXMAIN $_{t_i}$ = Annual fixed maintenance material cost in year i (\$)
 FIXFAC = Fixed portion of total plant maintenance cost
 PERTMC = Ratio between total maintenance material cost and total staffing cost.

For SO₂ removal:

$$\text{FIXMAINS}_{t_i} = \text{FIXFACS}(\text{PERTMCS})(\text{TOTSTAFFS}_{t_b})(1 + e)^{t_i - t_b} \quad (\text{B.3})$$

where

FIXMAINS $_{t_i}$ = Annual fixed maintenance material cost for SO₂ removal in year i (\$)
 FIXFACS = Fixed portion of total plant maintenance cost for SO₂ removal

TABLE B.1. Staff Requirements for Coal-Fired Power Plants^(a)

Number of Units	Coal-Fired Without SO ₂ Removal 701 - 1400 MWe				Coal-Fired With SO ₂ Removal 701 - 1400 MWe			
	1	2	3	4	1	2	3	4
<u>Plant Manager's Office</u>								
Management Staff	2 28	2 35	4 63	4 70	2 28	2 35	4 63	4 70
<u>Plant Operations</u>								
Supervision Staff	2 54	4 68	6 122	8 136	3 69	4 98	7 167	8 196
<u>Plant Technical and Engineering</u>								
Supervision Staff	2 20	3 24	5 44	6 48	2 20	4 24	6 44	8 48
<u>Plant Maintenance</u>								
Supervision Staff	2 90	4 120	6 210	8 240	3 130	5 176	8 306	10 352
Plant Total	200	260	460	520	257	348	605	696

(a) UE&C 1979.

PERTMCS = Ratio between total maintenance material cost and total staffing cost for SO₂ removal.

Cooling system O&M cost is calculated separately:

$$FMMCS_{t_i} = FMMCS_{t_b} (1 + e)^{t_i - t_b} \quad (B.4)$$

where

$FMMCS_{t_i, t_b}$ = Fixed maintenance material cost for cooling system in t_i and t_b dollars, respectively.

Variable Maintenance Material Cost:

$$VMAIN_{t_i} = (1 - FIXFAC)(PERTMC)(TOTSTAFF_{t_b})(1 + e)^{t_i - t_b} \quad (B.5)$$

where

$VMAIN_{t_i}$ = Variable maintenance material cost in year i (\$).

$$VMAINS_{t_i} = (1 - FIXFACS)(PERTMCS)(TOTSTAFFS_{t_b})(1 + e)^{t_i - t_b} \quad (B.6)$$

where

$VMAINS_{t_i}$ = Variable maintenance material cost for SO_2 removal in year i (\$).

Cooling system O&M cost is calculated separately:

$$VMMCS_{t_i} = \frac{VMMCS_{t_b} (ENGTOT)(1 + e)^{t_i - t_b}}{1000} \quad (B.7)$$

where

$VMMCS_{t_i, t_b}$ = Variable maintenance material cost for cooling system in year i and base year respectively (\$).

ENGTOT = Total annual station energy generation (kWh).

Fixed Supplies and Expenses:

$$FIXSE_{t_i} = FIXSE_{t_b} (KWOUT)(1 + e)^{t_i - t_b} \quad (B.8)$$

where

$FIXSE_{t_i}$ = Cost of fixed supplies and expenses in year i (\$)

$FIXSE_{t_b}$ = Cost of fixed supplies and expenses in base year (\$/kW)

KWOUT = Total net station output (kW).

Variable Supplies and Expenses:

$$\text{VARSE}_{t_i} = \frac{\text{VARSE}_{t_b} (\text{ENGTOT})(1 + e)^{t_i - t_b}}{1000} \quad (\text{B.9})$$

where

VARSE_{t_i} = Cost of variable supplies and expenses in year i (\$)

VARSE_{t_b} = Cost of variable supplies and expenses in base year (mills/kWh).

Cost of variable supplies and expenses for SO₂ removal is calculated separately:

$$\text{VAERSO2}_{t_i} = [(\text{LCOST}_{t_b})(\text{LRATE})] + [(\text{SCOST}_{t_b})(\text{SRATE})] \quad (\text{B.10})$$
$$[\text{PERSUR}] [\text{COALRATE}] [\text{OPHR}] [1 + e]^{t_i - t_b}$$

where

VARSO2_{t_i} = Cost of variable supplies and expenses for SO₂ removal in year i (\$)

LCOST_{t_b} = Cost of limestone in base year (\$/ton)

LRATE = Ratio of tons of limestone needed to remove a ton of sulfur

SCOST_{t_b} = Cost of sludge disposal in base year (\$/ton)

SRATE = Ratio of tons of sludge produced per ton of sulfur removed

PERSUR = Sulfur content by weight in coal (fraction)

COALRATE = Coal burning rate for the station (tons/hr)

OPHR = Annual hours of plant operation (hr).

Administrative and General Expenses:

$$\text{AGEX}_{t_i} = \text{PERAG} (\text{TOTSTAFF}_{t_i} + \text{FIXMAIN}_{t_i} + \text{FIXSE}_{t_i}) \quad (\text{B.11})$$

where

$AGEX_{t_i}$ = Administrative and general expenses in year i (\$)

PERAG = Percent of total staff, fixed maintenance materials and fixed supplies and expenses for administrative and general expenses (fraction).

Administrative and general expenses for SO₂ removal is calculated separately:

$$AGSO2_{t_i} = PERSO2 (TOTSTAFFS_{t_i} + FIXMAINS_{t_i}) \quad (B.12)$$

where

$AGSO2_{t_i}$ = Administrative and general expenses for SO₂ removal

PERSO2 = Percent of total additional staff and fixed maintenance materials required for SO₂ removal that are A&G expenses.

AN EXAMPLE CALCULATION

The annual operating and maintenance cost for a single unit 1000 MW coal-fired power plant with limestone SO₂ removal and mechanical draft wet cooling towers was calculated using the above equations. The list of assumptions used in this calculation is listed in Table B.2 and represents reasonable values for the year 1976.

The total annual O&M cost was estimated to be \$13.9 million in 1979 dollars. This is equivalent to 2.27 mills/kWh at a 70% capacity factor. If two 1000 MW units are used, the total cost is \$21.66 million or \$10.83 million per unit in 1979 dollars (1.77 mills/kWh, 70% capacity factor).

The annual O&M costs for selected coal-fired plants is listed in Table B.3. These plants are similar in capacity and coal type to the reference plant used in this analysis. A range of 1.18 to 4.22 mills/kWh is obtained after adjusting costs in Table B.3 for inflation to 1979 dollars. This is consistent with the previously estimated value of 2.27 mills/kWh for a 1000 MW plant.

TABLE B.2. Assumptions Used to Calculate O&M Cost
for a 1000 MW Coal-Fired Plant^(a)

COALRATE = 544 tons/hr	PERAG = 0.1
	PERSO2 = 0.1
e = 6%	PERSUR = 0.008
ENGTOT = 8.76×10^6 kWh	PERTMC = 0.45
FIXFAC = 0.75	PERTMCS = 1.00
FIXFACS = 0.33	SALARY _{t_b} = \$18,900
FIXMAINS = $\$0.42 \times 10^6$	SCOST _{t_b} = 5.25 \$/ton
FIXSE _{t_b} = 1.103 \$/kW	SRATE = 10
FMMCS = \$26,200	t _i = 1979
KWOUT = 1×10^6 kW	t _b = 1976
LCOST _{t_b} = 5.25 \$/ton	TOTSTAFF _{t_b} = $\$3.78 \times 10^6$
LRATE = 4	TOTSTAFFS _{t_b} = $\$1.08 \times 10$
NMAN = 200	VARSE _{t_b} = 0.0305 mills/kWh
NMANS = 57	VMMCS _{t_b} = 0.0042 mills/kWh
OPHR = 6,132 hr	

(a) Based on UE&C 1979.

TABLE B.3. Operating and Maintenance Cost for Selected Plants in 1977^(a)

Plant Name	State	Capacity (MW)	Capacity Factor (%)	Cost (mills/kWh)	Coal Heat Value (Btu/lb)
Jim Bridger	WY	1680	69	1.05	9309
Dave Johnson	WY	817	74	2.01	7460
Centralia	WA	1460	70	1.67	8100
Colstrip 1	MT	717	55	2.50	8736
LaCynge	MO	1580	33	2.84	9089
Waukegan	IL	933	40	3.51	9484
Kinkaid	IL	1320	44	2.17	9943
E. D. Edwards	IL	780	43	2.04	9570
Four Corners 1, 2, and 3	NM	634	62	3.79	8762

(a) DOE/EIA, 1978.

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