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Industrial and export potential of Northern Great Plains coal

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The University of Montana

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INDUSTRIAL AND EXPORT POTENTIAL OF NORTHERN GREAT PLAINS COAL

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The current demand for Northern Great Plains coal is dominated by the demand from electric utility fossil fuel plants. However, approximately 5% of the coal contracts are not from utilities and are probably used by industry and for other retail sales. This industrial use of the coal in the Northwest is little understood. Also, a much discussed potential for future demand is the possibility of export sales to the Far East. The major purpose of this study is to specify and estimate the potential demand from these different markets based on an economic spatial market analysis.

Assuming that both industries and the buyers in the Far East are attempting to minimize expenditures on energy using facilities, it is possible to model the cost process from mine to point of consumption in order to predict market behavior. In the industrial market this is modeled as a spatial competition of the coal with other fuels and against other Western coals. A survey of industrial coal users is used to check the results of the economic prediction model. In the analysis of the export market both international coal sources and U.S. coal sources compete for the Pacific Rim demand for coal. Other issues that may impact on this procedure are addressed such as the technical feasibility of coal substitution in industrial processes, the economics of industrial cogeneration, advanced combustion technologies and the sensitivity of specific industries to energy costs.

The estimates from the study indicate a very soft market for industrial and export sales of Northern Great Plains coal over the next twenty years. Based on the results, the industrial demand will probably be no greater than ten million tons per year by the year 2000. The majority of the demand will be from cement plants and near mine mouth steam production from industrial boilers. The export demand for Powder River coals is even more uncertain due to the deregulation of rail rates, the instability of world oil prices and the soft international economy. Results indicate a demand of from .7 to 10 million tons in export contracts to the Far East by the year 2000. Thus utility sales of the Northern Great Plains coals are forecasted to continue to dominate demand with industrial and export markets comprising less than 10% of total contracts.

ACKNOWLEDGEMENTS

The completion of this thesis was made possible from the combined efforts of many persons. I thank my committee (Arnold Silverman, John Duffield and Ron Erickson) for their continued support and assistance. Also, my colleagues, Mike Lee, Brad Harr and Don Snow deserve special recognition for their valuable contribution.

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CHAPTER ONE

STATEMENT OF THE PROBLEM

Problem

Considerable research has been conducted since the OPEC oil embargo of 1973 on the possibilities of using coal as a substitute industrial fuel in the U.S. for expensive supplies of petroleum. The Northern Great Plains subbituminous coal resource is known to be a vast low sulfur energy resource that has rapidly developed a market for utilization in central electrical generating plants (Duffield, Silverman et.al., 1982). Studies by the National Academy of Sciences (1979) and Silverman (1982) have identified potential U.S. demand for NGP coal from synthetic fuels programs. Research has not established the market potential of this coal for international export trade or for use in the industrial sector.

Many of the national studies to date have centered on economic constraints posed by environmental regulations with respect to fuel choice for industrial boiler applications. PEDCo Environmental (1978) investigated the costs of various boiler systems for the U.S. Environmental Protection Agency in order to ascertain the effects of New Source Performance Standards on the economics of the various fuel choices. ICF, Inc. (1977) and Energy and Environmental Analysis (1978) conducted similar research, which included pollution control costs in the decision process. However, even the highest projected fuel prices used in sensitivity of the two studies understandably failed to anticipate more recent world petroleum price increases. As a result, many of the conclusions are open to question. Little consideration has been given to the use of coal in industrial process heat applications and still less to implications of advanced fuel burning methods such as fluidized bed combustion and cogeneration.

The potential export market for NGP coal is a relatively new field of inquiry. The federal government Interagency Coal Export Task Force (D.O.E., 1980) and the World Coal Study (Wilson ed., 1980) have surveyed the national situation with some concentration on the Pacific Rim markets. However, the economics of export fuel choice from Western states to the Far East has received only superficial analysis.

In order to assess the potential demand for NGP coal created by these largely hypothetical markets, an economic spatial market model must be developed to account for competing substitute fuels and competing coal prices on a thermal basis as modified by transportation costs.

Objectives

A comprehensive analysis of the current developments of industrial export potential for NGP coal has yet to emerge. I propose to initiate such a study by compiling existing data, surveying current literature, and then by conducting analysis of identified areas of interest. Sensitivity analysis will be used to examine critical variables. The basis of the study would be an attempt to link real-world decisions with economically causal factors.

This thesis is organized as a series of sections, each dealing with a specific topic pertinent to the investigation. The following topics are included:

1. A survey of national industrial coal use with historical trends
2. A study of the economics of boiler fuel choice
3. A study of the economics of process heat fuel choice
4. A case study survey of industrial use of NGP coal
5. Advanced coal combustion technologies
6. Trends in industrial interfuel substitution
7. Prospects for industrial electrical cogeneration
8. Industrial energy intensiveness as a predictor for fuel substitution
9. NGP coal export potential
10. Qualitative concerns of coal use
11. Conclusions

Methodology

A comprehensive literature search is first required. Analysis would then proceed to identify specific areas of investigation such as the economics of boiler and process heat fuel choice, environmental regulations, export potential, advanced combustion technologies and qualitative concerns.

The national industrial coal use study will consist primarily of a survey of available literature and research. I will reexamine the economics of the fuel choice for both industrial and export sectors in light of current world oil prices. Cogeneration and advanced fuel combustion studies will concentrate on an analysis of the technological viability of these options. Sections on environmental regulation and normative concerns will address policy questions. The national trends in the industrial coal consumption Chapter will examine the substitution of petroleum fuels for coal in hopes of better understanding this phenomenon.

Finally, a case study survey will be conducted to provide evidence of industrial and export coal activity in the region in order to validate theoretical suppositions in the analysis.

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CHAPTER TWO

TRENDS IN INDUSTRIAL FUEL CONSUMPTION

History

From the beginning of the existence of the human species on earth, man has depended on the ability to gather and manipulate energy sources for survival and comfort.

About 8,000 Btus of food energy were consumed per capita, per day during the long period in which the species subsisted as hunters and gatherers (Odum, 1980). Primitive agriculture increased this rate of use to about 50,000 Btus per day. The industrial revolution of 1850 - 1870 greatly expanded the energy consumption to 280,000 Btu/day; while recent per capita use of energy in the United States was over 1.1 x 10^6 Btu (Cook, 1971). This period demonstrates a progressively accelerating move from a human population based on the diurnal solar flux to one predicated upon use of stored fossil fuel supplies of energy.

The advent of large scale manufacturing processes in the early 1800s in England signaled the Industrial Revolution and a dramatic increase in the use of energy. The transition was facilitated by coal whose higher heating value per unit weight and volume greatly reduced transportation costs and helped the fuel to increase its rate of market penetration. However, it was scarcity of fuel wood and the deforestation of vast areas of Elizabethan England that provided the initial impetus for coal's utilization (Rosenberg, 1973).

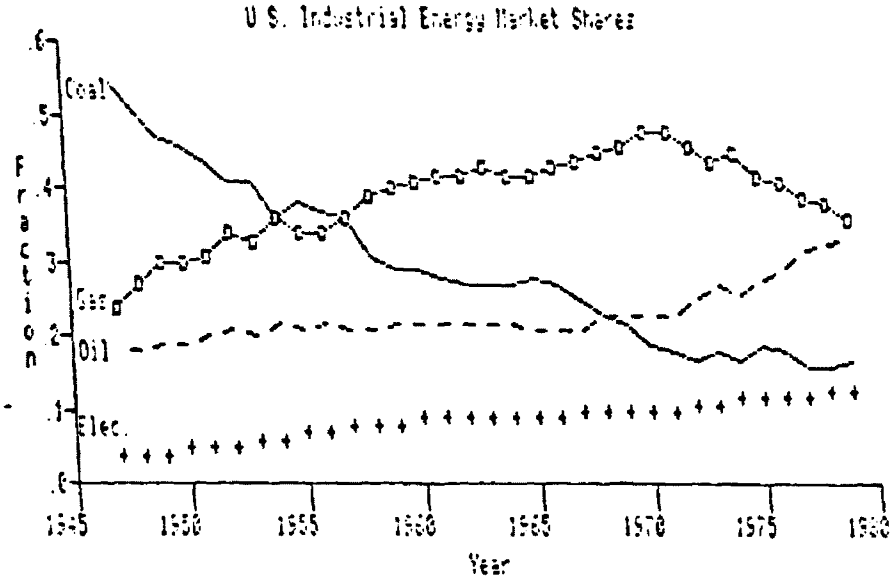
It is postulated that coal was initially the determinant factor over the emergence of the cultural and technological phenomenon known as industrialization. No longer constrained by animal and plant energies, man could now vastly increase productivity through the application of fossil energies. The steam engine was a natural adaptation of this available coal energy. In a similar fashion the internal combustion engine developed in response to the petroleum discoveries of the late nineteenth century. Later, an extensive natural gas distribution network has made this energy source widely available in the U.S., particularly in the industrial sector due to its clean burning properties and high heat content. More recently, nuclear electricity has become available for multi-sector use. In spite of three decades of research and development, its immediate future remains uncertain (Snow, 1981).

Analysis

A statistical data file was created based on records of industrial consumption since World War II. These records were changed from nominal units of consumption to common ones in terms of annual quadrillion Btus (quads) of each fuel used by the industrial sector. This was then normalized into a fractional market share presentation shown in Figure 2.1 similar to that used by Marchetti (1977). This graph includes all fuel use by the industrial sector; that is, process heat, process steam and feedstock use. Surprisingly, natural gas utilization has been declining without interruption since 1971 in terms of its fractional market share. On the other hand the growth in the fractional market share of oil has been relatively constant, only altered temporarily by the 1974 OPEC oil embargo! The relatively constant growth rate in the market penetration of electricity was an anticipated finding (Lee, 1981). Coal has been in a long period of decline from World War II to

Figure 2.1

U.S. Industrial Energy Market Shares



Source: U.S. Department of the Interior, 1975. "Energy Perspectives," Vol. 1 & 2, Washington D.C.

U.S. Department of Energy, 1981. Annual Report to Congress, DOE/EIA-0173, Washington D.C.

about 1972 at which point its fractional component has somewhat stabilized at approximately 18%. The data series for the next ten years will be critical in a long term evaluation of coal's market potential. Given the decline in natural gas dominance, it may be that coal will enter a new period of growth, albeit a slow one. The long term outlook for coal will be determined by changes in the reserve base of the various fuels by the cost of the available petroleum supplies to the sector and by conservation practices. Regulatory policies such as the Power Plant and Industrial Fuel Use Act, 1978 (PIFUA), the Public Utilities Regulatories Policy Act (PURPA) and the Natural Gas Policy Act (NGPA) may have an added effect depending on continuation and enforcement.

The history of industrial energy utilization follows three primary eras. The first was the use of wood for the purpose of manufacture of weapons and ornaments some 100,000 years ago. Until the utilization of coal in the nineteenth century, wood and other in-constant solar energies provided the entirety of man's energy needs.

During the succeeding century however, coal's fraction of the total U.S. energy market continued to increase along with the decline of dependence on wood. The introduction of oil in the 1860s had a similar result - oil's share of the total U.S. energy demand has continued to increase at the expense of coal. Figure 2.1 shows this trend of interfuel substitution for the U.S. from 1945 - 1980. Despite an abundance of potential fuel wood in the continental U.S. and also of coal reserves, both of these sources have been declining in fractions of total energy demand during the last century.

Past investigation has shown these growth and decline rates to be logarithmic in nature (Fisher, 1974). Figure 2.2 illustrates the growth in U.S. total energy consumption since 1850.

Total U.S. energy consumption increased by a steady 2.8% per year with a remarkable fit to a log-linear least squares regression. The correlation coefficient, using time as the dependent variable, was .98; R-squared was .96.

Given the fact the U.S. industrial sector is about 37% of the total U.S. energy demand (D.O.E., 1980), it is suspected that if there were time series data available from industry alone, such a line would be quite similar. Available information on industrial consumption from 1947 to 1982 indicates approximately a 2% annual growth rate in the annual demand for energy for that sector.

Fuel Substitution

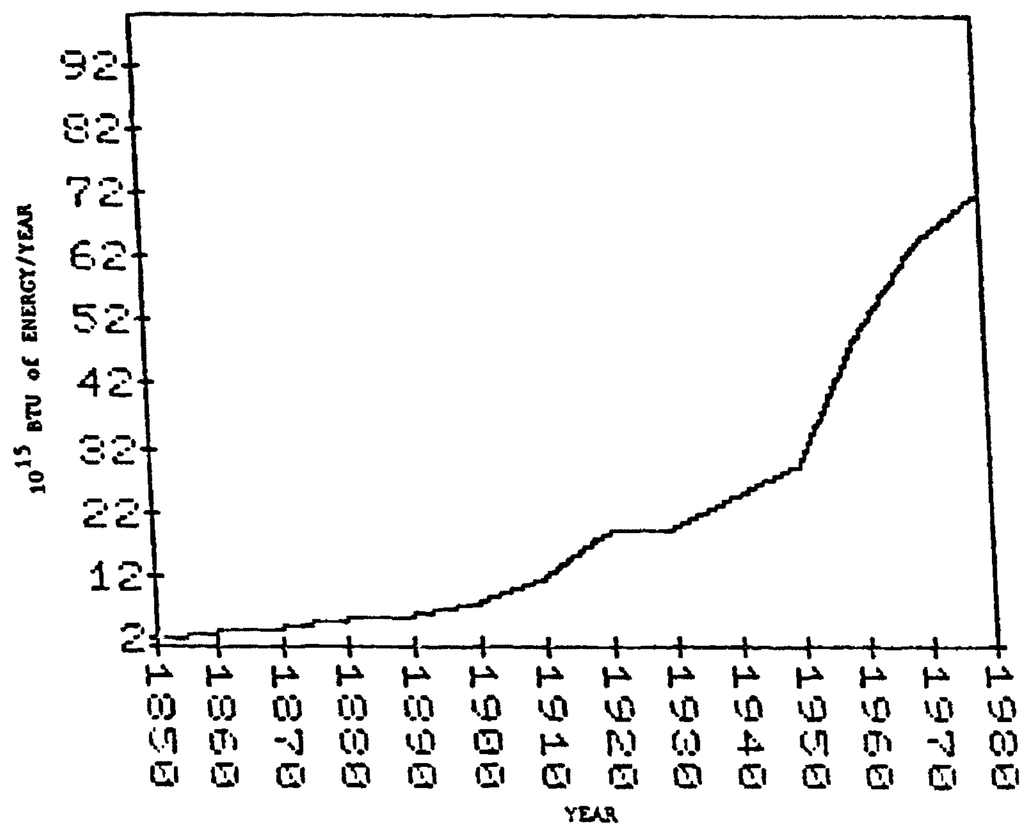
Marchetti (1977) has performed a study of world energy demand, illustrated in Figure 2.3 which displays a 2% annual growth rate in global energy demand since 1860. Marchetti believes that primary energy sources are substituted over time, based on logistics curves. Figure 2.4 illustrates the data fit with the actual historical data and predicted future values. Marchetti's analysis includes several controversial ideas:

1) Early rates of substitution, after an energy source's introduction, determines the shape of its logistics curve.

2) Revivals of declining energy sources do not occur (e.g., wood and coal will not reemerge as major energy sources).

Figure 2.2

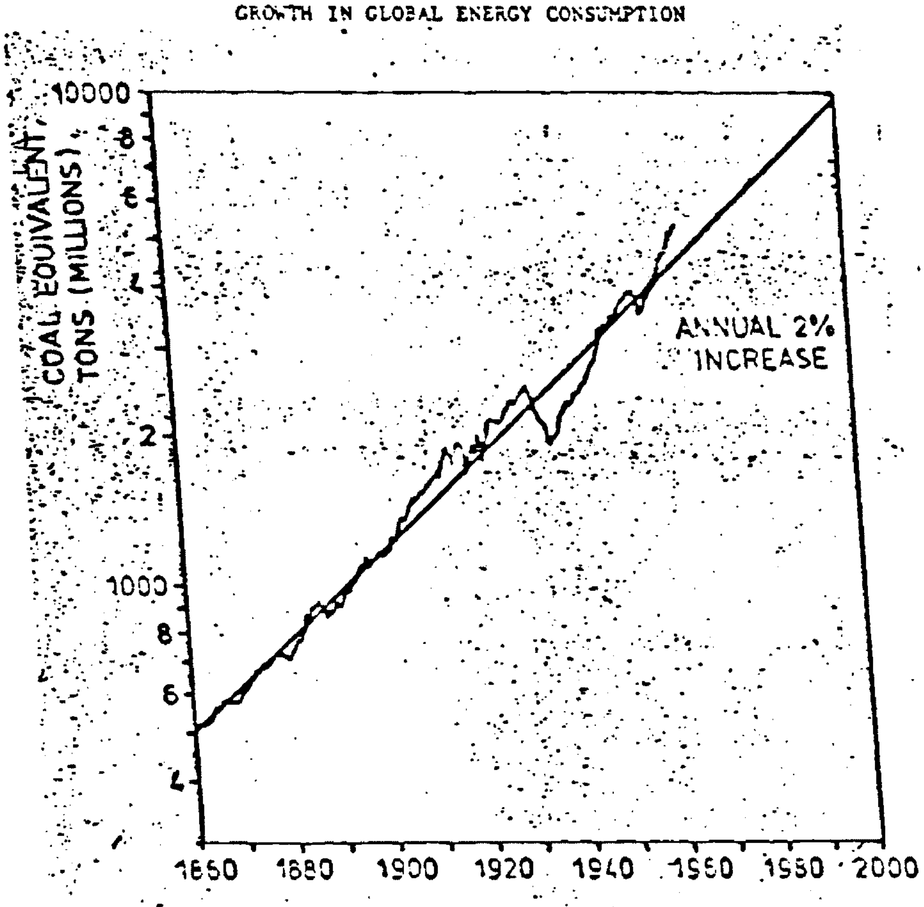
GROWTH IN ENERGY CONSUMPTION IN THE U.S.
(1850-1980)



Source: Schurr and Netschert, 1960. Energy in the American Economy, Resources for the Future, John Hopkins Press, Baltimore, Md.
DOE, 1981. Annual Report to Congress, DOE/EIA-0173, Washington D.C.

Figure 2.3

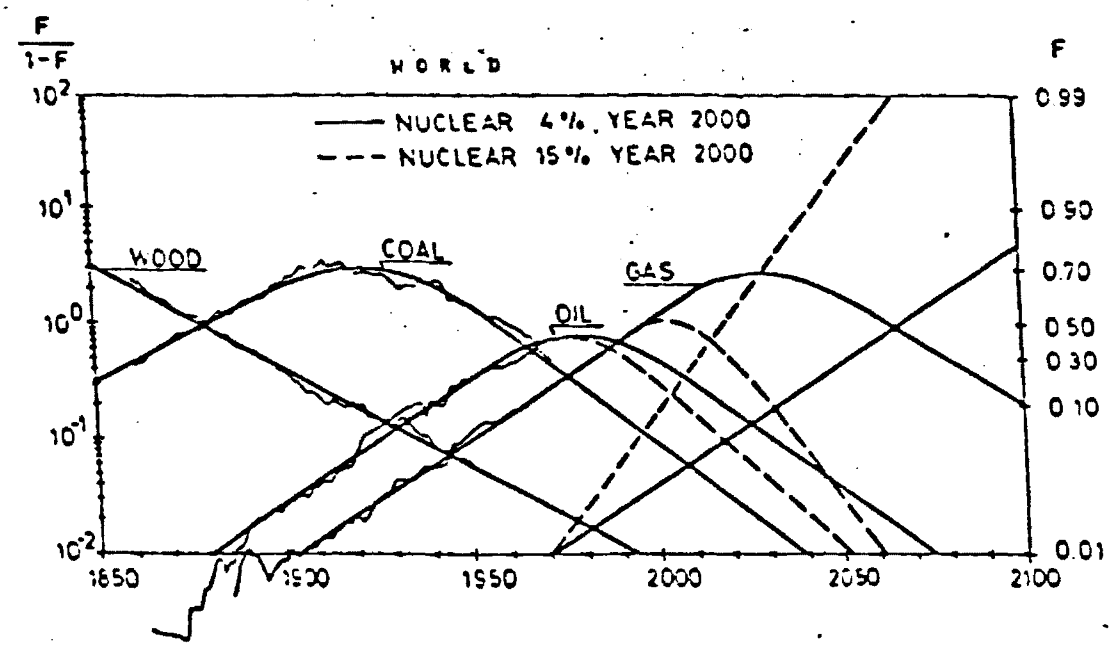
GROWTH IN GLOBAL ENERGY CONSUMPTION



Source: Marchetti, et. al., 1978. Dynamics of Energy Systems and the Logistic Substitution Model, International Institute for Applied Systems Analysis, Laxenbourg, Austria.

Figure 2.4

HISTORICAL AND PROJECTED MARKET SHARES FOR WORLD FUEL SUPPLY



Source: Marchetti, et. al., 1978. Dynamics of Energy Systems and the Logistic Substitution Model, International Institute for Applied Systems Analysis, Laxenbourg, Austria.

3) The substitution rates are very stable, regardless of wars and economic fluctuation.

4) Prices of energy sources may be effects rather than causes of changes in demand.

5) Substitutions proceed at a very slow pace and it takes a century for an energy source to go from one percent of the energy market to 50% of the total. Consequently, rapid changes in the energy mix are doubtful. Governmental projects for rapid fuel switching or energy independence are suspect.

6) Substitution possesses certain dynamics that are not necessarily influenced by exogenous factors such as the available reserve base.

The following questions arise with regard to the logic of his arguments:

1) If early rates of substitution determine the rate of market penetration, then how is a phenomenon such as the initial rise and recent decline of nuclear power explained?

2) If revivals of energy sources do not occur then how is the recent rise in national wood use and coal produced electricity explained in lieu of their previous decline?

These questions cast some doubt on Marchetti's conclusions. Fuels do seem to advance through periods of growth and decline, however it is less certain that a period of decline indicates absolute obsolescence. Could it be that fuel substitutions are more like sine functions than logistics curves? This scheme would allow for emergence of new fuel sources with the decline of old ones, or conversely, the reemergence of a fuel if other sources become constrained by the geologic resources or cost. Marchetti's assertion that substitution proceeds with little regard to the reserve base is in conflict with the much cited findings of Hubbert (1968) in which the author hypothesizes that the ultimate production of an energy resources can be defined by "fixed initial supplies". The rate of consumption of the resource may be determined by factors exogenous to the model, although the final result must be the same. For the entire cycle of a mineral resource, the production rate begins at zero and assuming that the reserve base is geologic and not renewable in the frame of human time, it must return to zero. Thus Hubbert's fossil fuel of production algorithm:

$$P = dQ / dt$$

where:

P = the production rate

dQ = change in quantity remaining

dt = change in time

The curve of 'P' can be plotted arithmetically by derivation of the area underneath the curve against the absolute quantity of the resource initially available:

$$dA = Pdt = (dQ/dt)dt = dQ$$

Such a curve must necessarily have an area equal to 'Q', the initial calculated reserve base. To conform with this assumption, such a production curve must have a growth period to its maxima followed by a period of decline as the limits of the reserve base are reached. Figure 2.5 illustrates this cycle of production for natural gas. Says Hubbert:

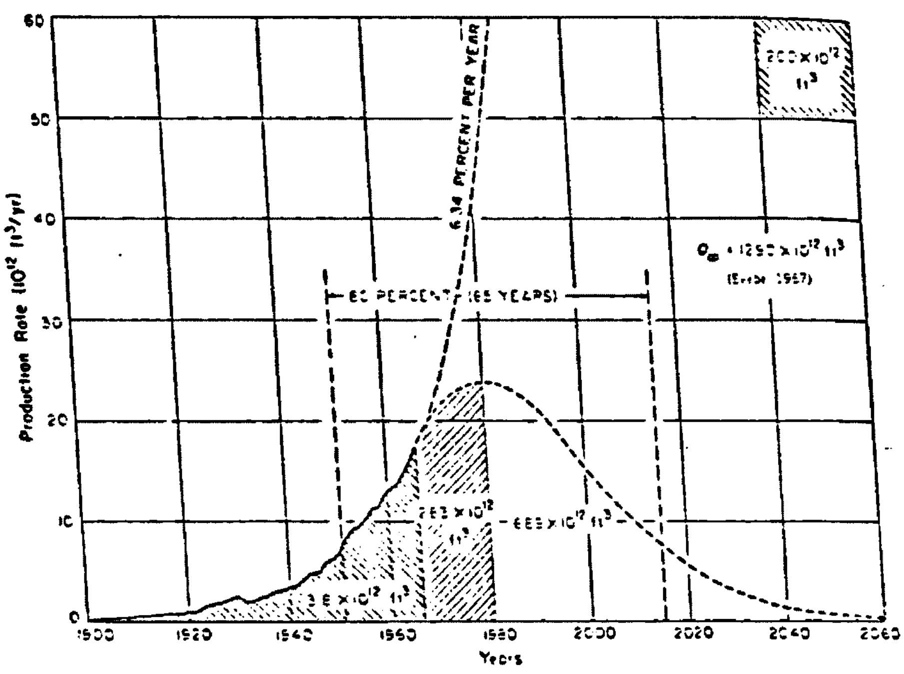
> "Mathematically, such a curve may assume an indefinite number of shapes, but the technology of production essentially requires that the early phase be one of a positive exponential rate of increase, and the declining phase an exponential rate of decrease, so between these two requirements, and that of the limitation of the area circumscribed, the amount of latitude in such a curve is greatly reduced."

Using various reserve estimates, Hubbert predicted that U.S. oil production would peak around 1970; natural gas production around 1980 and coal production around 2200 A.D. Hubbert believes that the total period of exploitation of fossil fuel energies on earth is short in terms of human history. When plotted on a time scale in increments of 1,000 years, this fossil fuel epoch appears in Figure 2.6 as a brief transitory "blip" in geologic history.

The question posed by Hubbert is significant. Given the limited extent of even the most optimistic estimates of petroleum reserves (Hendricks, 1965; Zapp, 1961 and others), increased reliance on non-petroleum energies appears certain. What might supplant coal in the next millenium after the decline of world coal production? The future

Figure 2.5

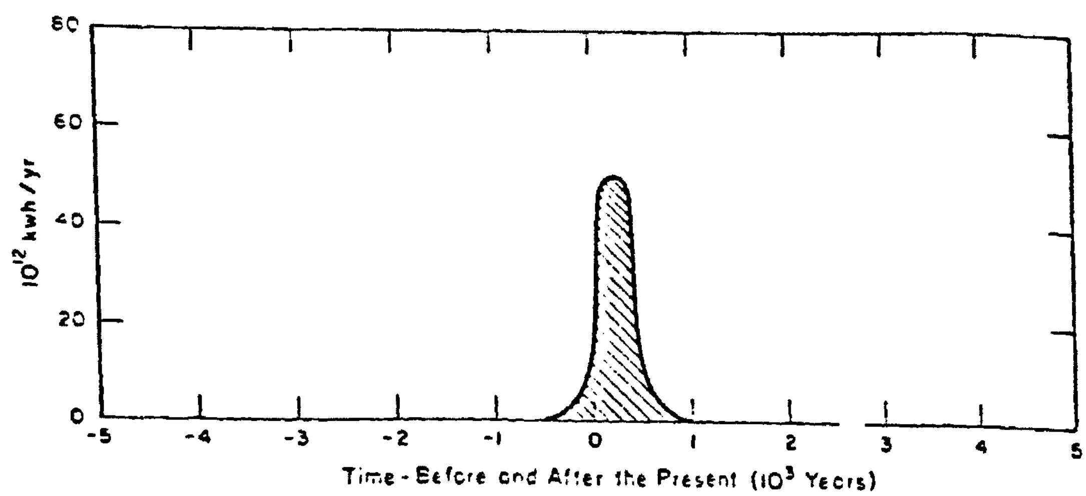
COMPLETE CYCLE OF NATURAL GAS PRODUCTION IN THE U.S.



Source: Hubbert, M.K., 1968. "Energy Resources," in Resources and Man, National Academy of Sciences, W.H. Freeman and Co., San Francisco, Calif.

Figure 2.6

EPOCH OF FOSSIL FUEL EXPLOITATION IN HISTORICAL PERSPECTIVE



Source: Hubbert, M.K., 1968. "Energy Resources," in Resources and Man, National Academy of Sciences, W.H. Freeman and Co., San Francisco, Calif.

of nuclear generated electricity seems obscure in light of the numerous reactor order cancellations and fiscal disasters (Snow, 1981). Solar energy is safe and abundant, but it is diffuse, interruptible and requires considerable capitalization for its use. While it may be applicable for some low heat process steam applications in the next century, widespread application is doubtful because of the concentrated heat necessary for many industrial processes (SERI, 1979). Other solutions such as fusion power, widespread geothermal or biofuels seem even more remote. Marchetti does seem correct in his assessment of the long market penetration times for new energy sources. It may be that nuclear and solar energies have not really established their rates of growth and this may not be evident before the turn of the century. Both Hubbert and Marchetti agree that these initial growth rates are descriptive of the exponential growth phase of energy sources. Hubbert found this growth rate to be 5.9% per year for oil production; 6.3% for natural gas and 3.6% for coal. The emergence of oil and natural gas as major energy sources is explained by their more rapid rates of market penetration than of coal. The initial growth rates of nuclear or solar energy introduction do not seem to follow the historically increasing rates of initial acceptance for new fuel sources. If one accepts Hubbert's hypothesis that petroleum sources are limited by their reserve base, then the only plausible short term future fuel mix would necessitate a renaissance of coal as a major energy source for industrialized countries. Implications for the coal rich regions of the

Northern Great Plains include slowly increasing industrial demand for this fuel in the future. This trend is not apt to be rapid until substantial constraints in natural gas supplies become apparent. According to Hubbert, because of the mathematic characteristics of exponential growth curves, even a doubling of the estimated world petroleum reserve base will only retard the world peak output from 1990 to the year 2000. Consequently, this period of substantial constraints in petroleum supply probably will not occur before the turn of the century. After that time, the dependence of the U.S. residential and transportation sectors on the limited supply of petroleum fuels will require an almost an industrial exodus from these sources into a fuel mix considerably more dependent on coal. Subsequent to this transition, the potential increase in industrial demand for Northern Great Plains coal could be considerable.

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CHAPTER THREE

INDUSTRIAL COAL DEMAND FORECASTS

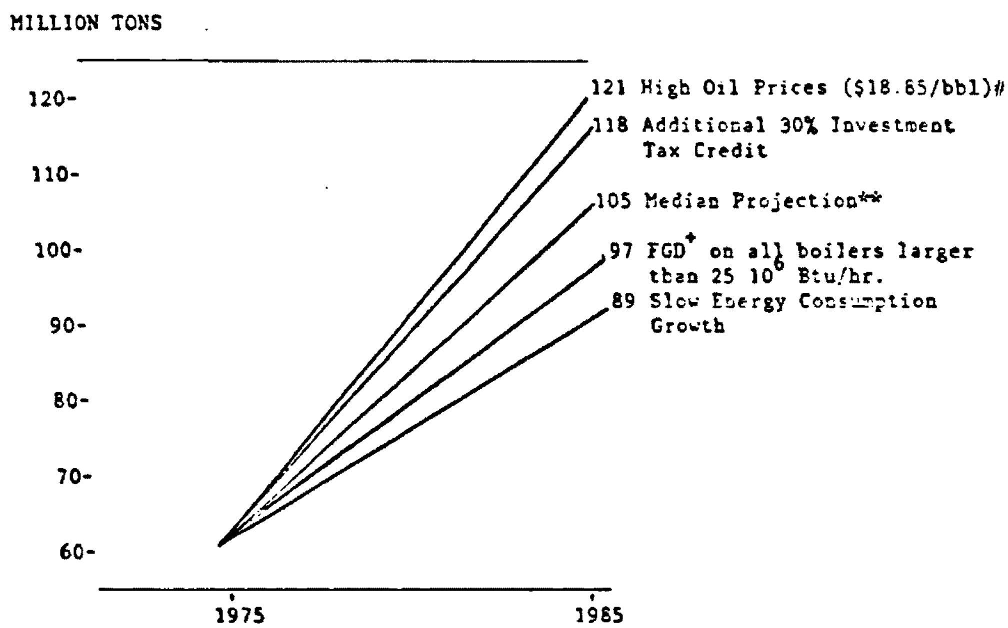
Industrial Coal Overview

Over the last 25 years coal use in the industrial sector has declined as manufacturing firms have switched to cheaper, more plentiful oil and natural gas (Figure 3.1). With increased oil and natural gas prices there may be a greater industrial coal use in the future although the industrial market will remain small compared to coal demand in the utility sector.

Coal's market share of industrial fuel has declined from about 20% in 1954 to about 6% in 1980 but is forecast to rebound to about 10% by 1990 (DOE, 1982). Even with increased use of coal in the industrial sector, use of oil and gas will still rise due to the necessity of clean burning fuels for process heaters. This is the largest energy consumptive functional use in the industrial sector (Table 3.1). Coal is a proven technology only for boilers and a few process heat applications such as cement kilns. Since 90% of existing boilers are not designed to burn coal, the potential for increased coal use in industry depends on the rate that firms purchase new boilers or replace existing units. This depends on new plant construction, the economics of competing fuel sources, and upon the positive and negative influences of mandatory coal use regulations and environmental air pollution standards.

To evaluate the current industrial coal uses for the NGP coal market and its future potential, models have been studied that forecast such future trends on a national level. Three such forecasting models

FIGURE 3.1
INDUSTRIAL COAL* DEMAND PROJECTIONS, 1985
(million tons)



* Steam coal; excludes metallurgical coal.
**Assumes oil price of $15.95, FGD on boilers larger than 250 10^6 Btu/hr, and 10 percent investment tax credit.
Flue gas desulfurization.
$ 1978 (constant) dollars.

Source: Manning and Heller, 1978. Coal and Profitability, McGraw-Hill Publications Co., N.Y.

have been identified. The summaries below include a brief description of each model.

Table 3.1
Industrial Sector Oil and Gas Consumption by Functional Use, 1974
(million coal ton equivalents)

Industry Group	Boiler	Raw Materials	Process Equipment	Other*	Total	% of Total Industrial Fuel Use
Food	18	-	4	4	26	4
Textiles	6	-	1	-	7	1
Paper	31	-	7	6	44	7
Chemicals	48	101	22	12	183	29
Petroleum	28	-	97	2	127	20
Stone, Clay and Glass	1	-	35	-	36	6
Primary Metals	13	4	48	9	74	11
All Other Industry	72	-	72	-	144	22
Total Industry	216	105	286	33	640	100

*Space heating and cooling, lighting, coke production, machine drive, other uses not specified by kind, and data not elsewhere classified.

Source: Energy and Environmental Analysis, Inc., 1977. Energy Consumption Data Base, Vol. 1 - Summary Document.

The Manning and Heller Study

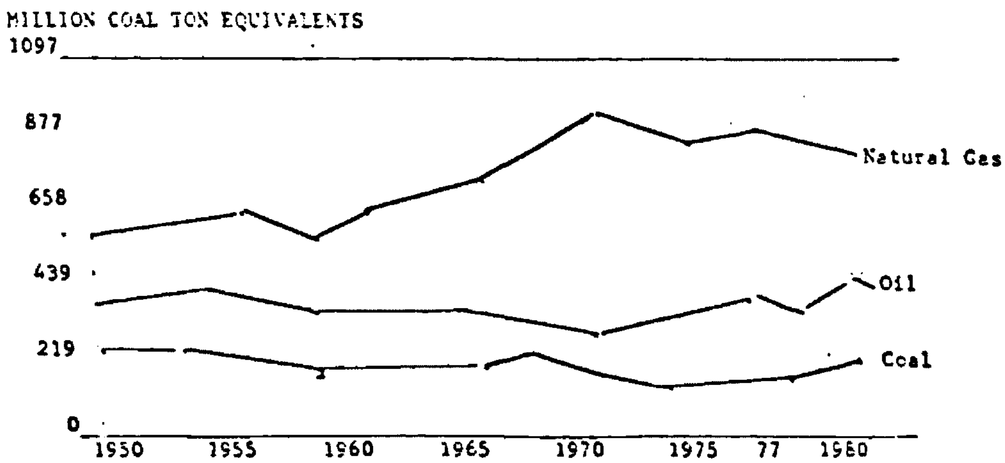
The study prepared by Manning and Heller (1978) in Coal and Profitability lists five possible scenarios for the growth of industrial coal use from 1975 to 1985. The low case examines a pattern of slow energy consumption growth. This model predicted about 88 million tons of industrial coal use by 1985. The second scenario assumes that the new EPA New Source Performance Standards will require FGD equipment on all boilers greater than 25 x 10^6 Btu capacity and thereby retard industrial potential. The median or most likely projection assumes an oil price of $15.95/BBL in 1978 constant dollars, FGD on boilers larger than 250 x 10^6 Btu/h and a 10% investment tax credit. This model predicts a demand of about 82 million tons for 1980 and 104 million tons for 1985. Consumption of industrial coal in 1979 was 67 million tons which is approximately that forecast for the low energy demand growth scenario. The rapid growth cases call for either an additional 30% investment tax credit or high world oil prices ($18.85/BBL). The projections are illustrated in Figure 3.2. Unfortunately, this study is of limited future value given its dated nature. The greatest significance to be drawn from this forecast is the shortfall of even median expectations for industrial conversions to coal as of 1980.

The D.O.E.Study

This study was completed by Cohen (1980) for the Office of Energy Use Analysis. The report forecasts that direct use of coal by industry in the next fifteen years will be confined to conventional boilers with the notable exception of coal fired cement and lime kilns. This discounts increased utilization due to gasification, fluidized bed combustion or MHD technologies. Even so, the D.O.E. study predicts that industrial use of coal will more than double by 1990 to 7.9 Quads/yr from a 1978 level of 3.4 Quads/yr. The rate of the increase in coal is based on two primary factors:

1) The provision of the 1978 National Energy Act that specifically increases the price of natural gas to industrial consumers, the Industrial Fuel Use Act which prohibits the use of oil and natural gas in new boilers with a firing rate of 100 x 10^6 Btu/hr or more and the Energy Tax Act which provides investment tax credits and accelerated depreciation methods for investments in coal.

FIGURE 3.2
INDUSTRIAL FUEL CONSUMPTION*, 1950-1977
(million coal ton equivalents)



*Includes metallurgical coal.

Source: <u>Historical Statistics of the U.S.</u>, Table Series S25-31, M107-122, M147-161.
Energy and Environmental Analysis, Inc.: <u>Energy Consumption Data Base</u>, 1977.
<u>Statistical Abstract of the U.S.</u>, Table 210.
DOE: <u>Monthly Energy Review</u>, various issues.

2) Coal's current and projected relative fuel price advantage. This is based on increasing delivered nominal residual oil prices of 6.1% annually between 1979 and 1990, nearly 7.6% for natural gas and only 3.4% for coal. Table 3.2 summarizes the projections of fuel mix industrial energy prices that seem to be pivotal in the D.O.E. analysis. By 1995 coal delivered to the industrial sector is estimated to cost less than half of the price of natural gas and one third the price of fuel oil of similar heating value.

The industries that are identified as the most probable for new construction or conversion were the large boiler industries (paper and chemical plants) and cement and lime kilns. Those of small boiler size (e.g., textile and food industries) and requiring process heat are seen to be less attractive to coal use. An EPA report indicated about 7% of these boilers were capable of conversion.

The stone, clay and glass industries are predicted to vary considerably in their ability to use coal. Contamination problems prohibit coal use in glass manufacture while it forms a necessary raw material in the production of cement. Coal use in cement and lime kilns are projected to dominate this category.

Table 3.2
Industrial Energy Prices -- History and 1979 Annual Report to Congress, Medium Case Projections, 1965-1995
(1979 dollars per 10^6 Btu)

Fuel	History 1965	1973	1978	Projections 1990	1995
Electricity	6.41	5.96	8.34	12.18	11.96
Distillate Oil	2.29	2.33	3.60	7.18	7.85
Residual Oil	1.24	1.72	2.49	6.22	6.83
Liquid Gas	1.90	2.37	3.42	8.83	9.56
Coal	1.03	.98	1.34	2.26	2.36
Natural Gas	.76	.75	1.56	4.85	5.40

Source: Energy Information Administration, 1979. Annual Report to Congress, 1979, Table 4.3.

Use of coal in the chemical industry varies considerably. Probability of conversion in paper mills is likely. Other applications such as petroleum refining, ammonia and ethelyene production are less likely due to heat control considerations.

Only products in the metals industry that can allow levels of contamination associated with coal use are forecast for conversion to coal. The most noteworthy is that of the displacement of natural gas in the steel industry by coal utilization.

Other factors that influence the future market penetration of coal into industry are those concerned with environmental regulation, the capital cost of coal vs. oil or gas fired burners and associated fuel storage and handling requirements.

Environmental regulations that affect coal use in industry are:

1) The Clean Air Act (1970) and the Clean Air Act Amendment (1977) which have increased the cost of burning coal vs. low sulfur oil or natural gas.

2) The National Ambient Air Quality Standards which govern both short and long term emission limits and designation of non-attainment areas.

3) State Implementation Plans (SIPs) which vary according to state implementation and enforcement of the provisions of the Clean Air Act.

4) New Source Review of new sources of air pollution by states for possible implementation of suitable control methods.

5) Prevention of Significant Deterioration (PSD) provision which limits air degradation in areas particularly those classified as "clean air" areas.

6) New Source Performance Standards are Federal standards on new or modified stationary pollution sources. These limits are now being revised by EPA.

Since natural gas and distillate oil are relatively clean burning fuels, they do not require expensive F.G.D. equipment that is necessary for coal fired combustion. Until the New Source Performance Standards are effectively evaluated many industries are hesitant to convert to coal given possible retroactive environmental costs and constraints on small boilers. The low capital cost for burners and ease in handling of natural gas are prime reasons for its increase in the market share of industrial fuel use. Most firms consider a far shorter payback period than the physical life of the equipment. Many companies use discounted cash flow analyses for only five years because of a desire to minimize capital expenditures on energy facilities given high current lending rates and uncertain future fuel prices. There is general consensus that a coal fired facility for industry will have a first cost 3-4 times as much as a natural gas burner of similar capacity. This may be of greater economic significance than project life life-cycle cost.

D.O.E. feels that enforcement of the provisions of the 1978 National Energy Act coupled with fuel price advantages will result in substantial increases in industrial coal demand compared to other fuels. Table 3.4 summarizes these predictions. Unlike the N.C.A. forecasts, the D.O.E. projections include metallurgical coal use in their forecasts.

National Coal Association Study

The N.C.A. Long Term Forecast is generally the least optimistic of the three cited studies as to the utilization of coal in industrial markets over the next ten years. The forecast is divided into "several" scenarios.

The most likely scenario according to N.C.A. assumes moderately rising oil and natural gas prices, continuing environmental constraints on the use of coal and a steadily decreasing energy input per industrial unit output of 1.5% annually. Of course, such an assumption becomes absurd if the analysis period is longer than 5-10 years.

Table 3.3
Industrial Energy Consumption; History and Projections, 1965-1995

	History						Projections[a]			
Fuel	1965		1973		1978		1990		1995	
Electricity	1.5	8.2%	2.3	10.0%	2.7	12.3%	4.6	17.2%	5.5	18.6%
Distillate Oil	0.7	3.8%	0.9	3.9%	1.2	5.5%	0.4	1.5%	0.4	0.4%
Residual Oil	1.2	6.6%	1.3	5.7%	1.5	6.8%	0.1	0.4%	0.2	0.7%
Liquid Oil	0.3	1.6%	0.6	2.6%	0.8	3.6%	0.7	2.6%	0.8	2.7%
Coal[b]	5.4	29.5%	4.4	19.2%	3.4	15.5%	7.3	27.2%	7.9	26.8%
Natural Gas	6.8	37.2%	9.6	41.9%	7.9	35.9%	7.8	29.1%	8.1	27.5%
Other	2.5	13.7%	3.8	16.6%	4.5	20.0%	6.0	22.4%	6.7	22.7%
Total	18.3		22.9		22.0		26.8		29.5	

[a]Medium World Oil Prices projection series, Energy Information Administration, Annual Report to Congress, 1979, p. 93.

[b]Coal consumption includes metallurgical coal consumption.

Note: Column A lists quadrillion Btu; Column B lists percentages. Quadrillion Btu is used in this table in order to facilitate comparisons among fuels. Many coal consumption numbers in the text are derived from this table based on a conversion factor of 22.5 x 10^6 Btu per ton.

The low forecast assumes stronger environmental restrictions and/or slow industrial economic growth coupled with large numbers of extensions in the provisions of the 1978 Fuel Use Act. The high forecast assumes greater increases in oil and natural gas prices and government enforcement of the Fuel Use Act or increase investment taxes.

The results of this forecast are summarized in Table 3.4. The study shows industrial coal use doubling by 1990 at an annual growth rate of 6.6%.

N.C.A. lists several variables that offer a large potential influence on the above forecast. These include:

1) The revised New Source Performance Standards.

2) The PSD and Non-attainment Standards which may preclude coal use in already degraded industrial areas.

3) Federal oil and natural gas controls can affect conversion to coal specifically if extension or rapid decontrol should ensue. For example, decontrol of oil but not natural gas would encourage continued and increased reliance on natural gas.

4) World oil prices that are controlled by OPEC and increase moderately.

5) Technology improvements or breakthroughs in coal utilization or FGD such as MHD, fluidized bed combustion or gasification.

6) Conservation along with further reductions of energy use per unit output.

7) Industrial growth of an otherwise sluggish economy.

The forecast was based on an analysis of likely growth in energy use within the various industrial sectors. N.C.A. states that the industrial market is difficult to predict because of the "lack of reliable data on coal and the multiplicity of uses of energy in the industrial sector."

In order to predict future demand more accurately N.C.A. studies the seven major sectors of industry that use steaming coal in regard to their most current consumption rates and the market share of coal versus natural gas and residual oil. Table 3.5 summarizes these findings. The chemical and cement industries dominate 1979 consuumption although much of the use of coal in the chemical industry is as a feedstock raw material used in manufacture. The only major user with well established coal demand is the paper products industry.

Table 3.6 shows coal's market share of the industrial energy base as compared with oil, gas and electricity, including N.C.A.'s forecast of how the market share of each fuel will change from 1979 to 1990. In spite of existing investment incentives and that of O&M price advantages, it predicts only a slight increase in coal's market share of the industrial energy supply.

N.C.A. advises that the model of industrial coal growth is very sensitive to:

1) Industrial production growth rates,
2) Availability and price of competing fuels,
3) Environmental regulations regarding coal use.

Table 3.4
Long Term Industrial Coal Forecast

	Industrial/Retail Coal Consumption (Million Tons)		
	1979	1985	1990
Low		87	113
Most Likely	77	107	160
High		120	196

Source: N.C.A., 1980. "Industrial and Retail Market Long Term Fore-cast", Washington, D.C.

Table 3.5
1979 Industrial Coal Consumption by Sector and Market Share

Industry	1979 Coal Consumption (Million Tons)	1979 Market Share Coal	Other Fuels
Chemicals & Products	14.7	12%	88%
Cement	12.2	61%	39%
Other Stone, Clay & Glass	2.1	27%	73%
Paper & Products	8.5	16%	84%
Residential & Commercial	7.1	1%	99%
Food & Kindred Products	3.9	10%	90%
Primary Metals	4.6	5%	95%
Others	21.2	—	—
Total	74.0		

Source: N.C.A., 1980. "Industrial and Retail Market Long Term Fore-cast", Washington, D.C.

Table 3.6
Industrial Fuel Market Share Forecast

	Market Share of Industrial Energy 1979	1985	1990
Coal	8%	10%	13%
Oil	16%	14%	13%
Gas	44%	39%	36%
Electricity	13%	14%	14%
Other	19%	23%	24%

Source: N.C.A., 1980. "Industrial and Retail Market Long Term Fore-cast", Washington, D.C.

Comparison of the Forecasts

It is difficult to compare the three studies since the forecast periods for each do not coincide in any continuous sense. Perhaps the most useful comparison possible is a compilation of 1990 proejctions for industrial coal use including metallurgical coal use in Quad But's. This is listed in Table 3.8.

In the short run the Manning and Heller study agrees closely with the N.C.A. forecast. However, there is considerable disparity between the DOE 1990 forecast and that of N.C.A. There appears to be a significant disagreement in historical data between the two studies. DOE lists the 1978 industrial coal use as 3.4 Quads while N.C.A.'s study evidences only 2.3 Quads including metallurgical coal use for 1979.

The DOE forecast shows industrial coal use increasing dramatically from 1978 to 1990 by over 100% and then increasing slowly to 1995, while N.C.A. details the greatest portion of such an increase from 1985 to 1990 (a 72% increase in consumption in five years). The N.C.A. projections for 1990 are significantly less than that of DOE (3.9 Quads vs. 7.3 Quads). Which is to be believed? The 1980 data for industrial consumption of coal agrees best with the low forecast by Manning and Heller or N.C.A.

Table 3.7

INDUSTRIAL FUEL USE
(QUAD BTU'S)

	COAL	COKE[1/]	FUEL OIL	NATURAL GAS	ELECTRICITY	OTHER[2/]	TOTAL[3/]
1955	2.5	1.2	1.7	4.9	0.8	1.3	12.4
1973	1.8	0.5	2.6	10.0	2.2	2.7	19.7
1979	1.8	0.5	3.4	9.4	2.9	3.7	21.6
1985	2.0/2.3/2.6[4/]	0.5/0.5/0.5	3.1/3.4/3.6	8.5/9.2/9.8	3.1/3.3/3.5	4.4/4.8/5.1	21.7/23.6/25.1
1990	2.6/3.4/4.0	0.5/0.5/0.5	3.0/3.4/3.9	8.3/9.6/10.8	3.4/3.8/4.2	5.0/5.8/6.6	22.7/26.6/30.0

1/ COKE -- Historical data defined as used in Census of Manufactures Data: Assumed constant in forecasts.

2/ OTHER -- Defined as used in Census of Manufactures Data.

3/ Totals may not agree with the sum of each category due to rounding.

4/ Low, most likely and high forecasts.

Table 3.8
Industrial Coal Consumption Forecasts
For 1985 - 1995 Including Metallurgical Coals
QUAD/Btus

		1985	1990	1995
DOE		-	7.3	7.9
N.C.A.	low	2.5	3.1	-
	mid	2.8	3.9	-
	high	3.1	4.5	-
Manning & * Heller	low	2.5	-	-
	mid	2.9	-	-
	high	3.2	-	-

*.5 Quad Btu added to projections for metallurgical coal equivalent.

Significance for the NGP Study

There is a general consensus that industrial expansion of coal use in the next ten to fifteen years will be confined to large new boilers or heaters of the following industry types:

1) Cement and lime industry

2) Chemical products

3) Paper industry

Although the NGP coal is of a generally lower sulfur content than eastern coals, all three models have emphasized the sensitivity of industrial coal economics of the required FGD control equipment as modified by State Implementation Plans.

References

Cohen, Barry 1980. The Substitution of Coal for Oil and Natural Gas in the Industrial Sector, DOE/EIA-TR-0253, Washington, D.C.

D.O.E., 1980. Annual Report to Congress, DOE/EIA 0173, Washington, D.C.

Manning and Heller, 1978. Coal and Profitability, McGraw Hill Co., N.Y.

National Coal Association, 1980. "Industrial and Retail Market Long Term Forecast," Washington, D.C.

CHAPTER FOUR

INDUSTRIAL ENERGY INTENSIVENESS

Methods

In assessing the industry specific potential to convert to coal it is useful to develop a method to predict plant sensitivity to energy costs. This is most appropriately approximated by study of process specific energy intensity.

Not all industries are strongly influenced by energy costs. A study by EPRI (1980) of 33 manufacturing sectors in the U.S. found that energy represented for most industries only a small proportion of total output costs. Over a 1948-71 period, energy costs were under 1% of total costs for ten industries (food, tobacco, apparel, furniture, print, petroleum, leather, metals, electrical, machinery, instruments). Two industries had energy costs greater than 3% of total costs - stone, clay and glass and primary metals. Labor, raw materials, and transportation of goods to markets are other important determinants of production costs.

The energy intensity has been detailed by Hannon & Hereendeen (1975), Just (1974), Reardon (1974) and others. There are several methods of defining the energy intensity of an industry.

One method is simply the total energy by fuel that is used by a particular industry. Although useful with regard to evaluating total process energy demand within the industrial sector, it is strongly influenced by the size of the industry. It is also influenced by fluctuating market demand and production of the product. Table 4.1 and 4.2 illustrate this method of determination for the years 1970 and 1974.

Table 4.1
Largest Energy Consuming Sectors in the U.S. in 1970
(10^{15} Btu)

	Consumption	% of Total (85×10^{15} Btu)
Electric Utilities	28.701	34%
Residential	14.798	17%
Petroleum Refining	3.925	5%
Energy Exports	2.431	3%
Retail Trade	1.989	2%
Truck Transportation	1.830	2%
Air Transportation	1.497	2%
Steel	1.461	2%
Chemicals	1.457	2%
Paper/Woodproducts	1.392	2%
State/Local Government	1.256	2%
Rail Transportation	1.219	1%
Real Estate/Rental	1.190	1%
Wholesale Trade	1.097	1%
Food	1.078	1%
Stone, Clay & Glass	1.032	1%
	66.373	78%

Source: James Just (1974) Energy Intensiveness and Conservation Potential of U.S. Industries, Mitre Corporation, McLean, VA, P. 10-13.

Table 4.2
1974 Industrial Energy Consumption by Sector,
(10^{12} Btu)

Industry	Coal	Natural Gas	Distilled Oil	Residential Oil	Total
Food	75	476	67	66	721
Textiles	22	102	26	37	187
Paper	209	414	25	489	1,137
Chemicals	322	1,617	120	165	2,225
Petroleum Refining	5	1,111	50	282	1,449
Stone, Clay, Glass	234	696	76	50	1,056
Steel	170	682	15	250	1,117
Aluminum	31	411	17	17	476
Other[1]	247	2,798	760	201	4,062
Total	1,316	8,163	1,156	1,544	12,179

1 - manufacturing, agriculture, mining industries and miscellaneous.

Source: Energy and Environmental Analysis, 1980 Industrial Fuel Choice Analysis Model, Arlington, VA, Table 2-4.

Table 4.3
Most Energy Intensive Industries Per Dollar Output
($1970 U.S.)

Type	10^6 Btu/$1970 Output
Utilities	1.584
Paving/Asphalt	.668
Steel	.434
Cement/Lime	.410
Air Transportation	.241
Local Passenger Transportation	.155
Petroleum Refining	.142
Stone, Clay & Glass	.141
Paper	.130
Aluminum	.107

Source: Just, 1974, p. 14-17.

Table 4.4
Most Energy Intensive Industries Per
Dollar Final Demand ($1970 U.S.)

Type	Consumption Coefficient $1970 Demand/$10^6$ Btu
Utilities	3.210
Petroleum Refining	1.235
Coal Mining (Deep)	1.047
Cement	.900
Paving	.591
Asphalt	.422
Aluminum	.402
Primary Steel	.350
Foundaries	.286
Air Transportation	.281
Fertilizers	.221
Paper	.216
Local Passenger Transportation	.206

Source: Just, 1974, p. 18-21.

Table 4.5
Most Energy Intensive Sectors, U.S.
Economy - Direct & Indirect Energy Inputs

Type	(10^{15} BTU/YR)
Petroleum Refining	11.830
Utilities	11.013
New Construction	6.685
Food	3.881
Retail Trade	3.170
Motor Vehicles	2.873
Coal Mining (All)	2.800
Real Estate/Rental	2.081
Wholesale Trade	1.596
Medical & Education	1.494
Air Transportation	1.037
Hotel, Personal & Repair Service	.986
Truck Transportation	.921
Apparel	.907
Local Passenger Transportation	.899

Source: Just, 1974, p. 26.

A second definition is the energy consumption of an industry per dollar of output (Table 4.3). This is probably the most important determinant of firm behavior toward energy cost minimization. If energy costs per dollar output is high, conversation efforts will be more important. This criteria is not effected by the size of the industry, but does not account for inter-industry purchases. Thus, transportation costs may be masked by contracts with independent services. This is important since there is often a trade off between location and transportation cost for industries. Also, process inefficiencies must be accounted for in the analysis. This indicates a definition of energy intensity that identifies goods and services cross purchased by industries as part of their energy input per dollar final demand (Table 4.4). It is possible to calculate energy consumed by all industrial sectors resulting from a dollar of sales by a single industry. By applying the analytic technique of input-outout analysis (Leontif, 1966), it is possible to determine the energy consumed throughout the economy by a single purchase by final consumers such as individuals, governments and institutions (Yan, 1969). An input-output matrix is created and then inverted:

$$E_i = \sum_{k=1}^{K} E_{i,k} + E_{i,y}$$

where:

E_i = total energy output of sector 'i' in Btus

$E_{i,k}$ = energy sales from i to k in Btus

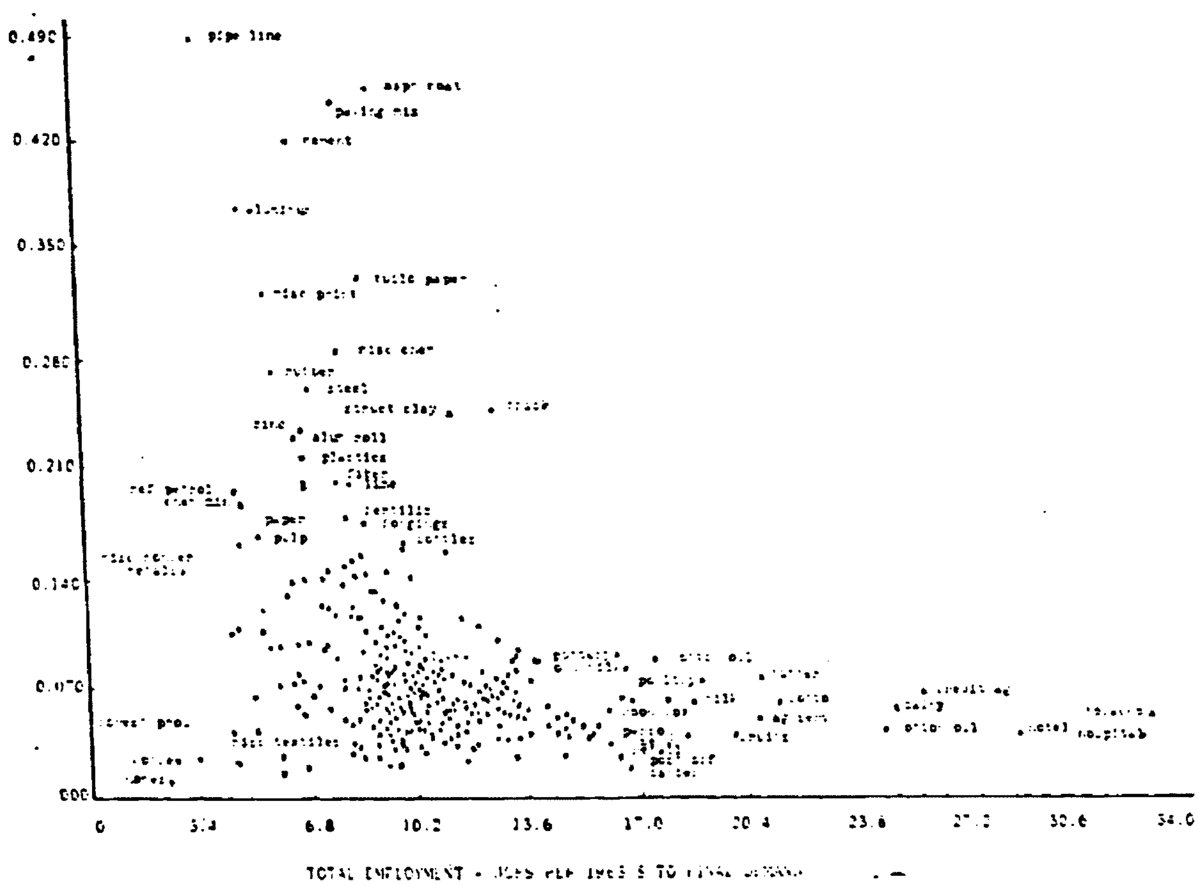
$E_{i,y}$ = energy of type: sold to final demand, element by element multiplication of 'n' sectors

The inverse coefficients calculated for Table 4.4 are weighted by the size of the final demand for that category's goods (Table 4.5). While direct energy consumption in new construction or local transportation is not high, the indirect energy requirements (cement/steel) makes them very energy intensive.

Figure 4.1 illustrates the findings of Hannon & Hereendeen (1975). A million Btus required by a particular industrial process is compared to a \$1963 of final demand in that sector against the jobs per \$1963 final demand. The figure illustrates not only the energy intensiveness

Figure 4.1

ENERGY AND EMPLOYMENT INTENSITY PER DOLLAR FINAL DEMAND FOR U.S. INDUSTRIES



Source: Hannon, B. and Herendeen, R., 1975. "Energy Research Group," Center for Advanced Computation, University of Illinois, Urbana, IL.

of various industries, but also its employment characteristics. While energy intensive industries are mixed in regards to their employment characteristics, all high energy sectors have lower employment ratios to dollar final demand. Agriculture and service institutions tend to use less energy per value output. They also employ large numbers of people in the production process.

Conclusions

Most energy intensive industries are not likely to use NGP coal. Given the scope of the study, utilities are not considered and paving and asphalt production which use petroleum derivatives are relatively unyielding in terms of fuel substitution. The raw materials necessary for steel production makes location of such plants in the market area unlikely.

The energy intensive industries identified that might be sensitive to substitution of NGP coal on a basis of cost minimization include the cement, stone, clay and glass and paper industries. Categories that might eventually use NGP coal given demonstrated commercial feasibility include the fertilizer and aluminum industries. Each of the energy cost sensitive categories identified above already have some application of NGP coal. The South Dakota cement plant is using about 300,000 tons per year of coal from Gillette, Wyoming and numerous bentonite drying kilns (stone, clay and glass) in the production area are using the fuel. Additionally, two paper plants in Wisconsin are using Montana coal. Use of NGP coal for ammonia production has been proposed for a plant near Circle, Montana. This application would fall under the fertilizer category identified in Table 4.4.

Use of NGP coal in the aluminum industry must await demonstrated engineering and economic feasibility before substitution is likely. Higher natural gas prices in the 1980s may provide incentive for experimentation with coal use in aluminum, node prebake ovens and reverbratory furnaces.

Local availability of wood for paper production could induce such industries to locate new plants proximate to cheap NGP coal sources. This is also true for the cement and lime industry and the stone, clay and glass categories. Since energy costs are a large portion of production costs for these industries such firms may seek to buffer themselves against future petroleum price uncertainty by entering into long-term contracts with Western coal producers.

References

EPRI, 1980. Dynamic Adjustment Models of Industrial Energy Demand, 1947-74. Electric Power Research Institute, EA-1613, Palo Alto, CA.

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CHAPTER FIVE

INDUSTRIAL BOILER FUEL CHOICE

Introduction

To anticipate future NGP coal demand, it is necessary to investigate the role of coal as an industrial boiler fuel in addition to its consumption in the utility market. During the 1950s and 1960s coal use in the industrial sector was in long-term decline with the development of larger packaged oil and natural gas-fired boilers and the emergence of stringent air pollution standards.

However, during the 1970s significant changes occurred in the supply and price of industrial petroleum fuels. The supply interruptions of the 1973 oil embargo and the 1979 natural gas shortage have made domestic consumers acutely aware of the vulnerability of this supply. The dramatic increase in the average price of imported oil due to decisions of the OPEC cartel, coupled with concern over deregulation of domestic petroleum pricing has renewed interest in coal as an industrial fuel based on its comparatively low price.

Although fuel use in boilers represents roughly one-third of all energy used by industry, coal is presently the fuel choice in comparatively few new boilers (EEA, 1979). Since the Powerplant and Industrial Fuel Use Act (PIFUA) has specified that coal must be the boiler fuel used unless it can be demonstrated in units with firing rates in excess of 100×10^6 Btu to be comparatively more expensive than oil or gas, there is a need to survey the economics of this fuel choice. Considerable research effort has centered on modeling this decision. Three separate reports have been submitted to the Congressional Budget Office, the Department of Energy and the Environmental Protection Agency. These studies are:

1. "Economic Considerations in Industrial Boiler Fuel," ICF, Inc., January 1979.
2. "Industrial Fuel Choice Analysis Model," Energy and Environmental Analysis, Inc., January 1979.
3. "Background Study in Support of New Source Performance Standards for Industrial Boilers," PEDCo Environmental, Inc., March 1979.

Each study outlines a procedure that models the decision process used by a firm in choosing boiler equipment and fuel types. The underlying assumption is that coal will be selected only if its total costs are lower than oil or natural gas with respect to risk, cost of capital, regulations, and investment period. There are specific variations in each study with respect to modeled boiler sizes, boiler fuel specifications, steam temperature and pressure, combustion types, and so forth. Each study used actual quotes for equipment cost estimation; the results of the studies were standardized for comparative purposes so that a range of variation might be identified. Since the studies have been completed, signficant increases have occurred in the price of imported oil and natural gas, which may have considerable impact on the resultant annualized costs used as a basis for fuel choice decision.

<u>The Modeled Boiler</u>

In order to compare these studies, it was decided to concentrate on a specific boiler size that was representative of current industrial use. Boiler population data were examined for the U.S. by size and installed thermal capacity. Table 5.1 summarizes this information:

Table 5.1
Distribution of Commercial/Industrial Boilers by Size

	Size (10^6 Btu/h)	Number	Installed Capacity (10^6 Btu/h)
1	.4 or less	970,980	236,100
2	.4 - 1.5	568,415	490,700
3	1.5 - 10	208,659	820,000
4	10 - 25	25,081	432,600
5	25 - 50	16,483	608,700
6	50 - 100	6,840	503,000
7	100 - 250	4,266	632,000
8	250 - 500	1,018	335,400
9	500 - 1500	253	191,400
10	1500	65	232,200

Source: PEDCo, Environmental, Inc. 1979. Background Study in Support of New Source Performance Standards for Industrial Boilers. Cincinnati, OH, p. 12.

The modeled boiler should be an industrial type representative of the class commanding the greatest installed thermal capacity. This critera was chosen because it correlates closely to the class of boiler that is both fuel-intensive and also commonly used by industry. It is only in larger boilers that fuel costs may make NGP coal the least-cost choice because of higher capital costs associated with such boilers. The smaller commercial boilers (those smaller than 25 x 10^6Btu/h) were eliminated because their capacity utilization is considerably lower than that of industrial boilers (PEDCo, 1979). This resulted in the choice of Class 7 (100-250 x 10^6Btu/h) boilers for analysis. From this class, a size was chosen that would allow comparison with boilers of equal size and also with larger and smaller boilers for proper representation of economies of scale. The model size is a boiler with a firing rate of 175 x 10^6Btu/h.

A consideration in the boiler model is the heat exchange configuration for water-tube, fire-tube, or cast iron models. Based on size, the modeled boiler was taken to be a water-tube type, which dominates the larger industrial units irrespective of fuel and accounts for most of the installed thermal capacity. The distribution of capacity by fuel type for water-tube boilers in 1977 is shown in Table 5.2.

Table 5.2
Distribution of Capacity by Fuel for all Water-Tube Boilers

Fuel	Total Capacity (10^6Btu/h)
Natural gas	1,045,900
Residual oil	755,700
Coal	618,600
Distillate oil	143,300

Source: PEDCo Environmental, Inc. 1979. Background Study in Support of New Source Performance Standards for Industrial Boilers. Cincinnati, OH, p.12.

It was decided to model each of the various fuel types listed. A coal-fired boiler was assumed to be a field-erected spreader/stoker system with an expected plant life of 30 years, while water-tube oil and gas systems would be prepackaged units with replacement in 15 years. Such prepackaged systems are normally shipped by rail and cost 15% to 30% less than the comparable field-erected unit (ICF, 1979).

The steam production of the units is an important parameter in the economic assessment, since it is the cost of this end-product that industry will attempt to reduce. A steam pressure of 650 psi and a temperature of 750°F for all boiler systems was assumed. For each pound of steam, 1200 Btu must be absorbed by the feedwater in order to reach this pressure and heat content (ICF, 1979). Table 5.3 lists the boiler efficiencies of the various fuel types and the associated steam production in thousands of pounds per hour).

Table 5.3
Boiler Efficiency and Steam Production for a 175 x 10^6 Btu Water-Tube Model

Fuel	Boiler Efficiency (%)	10^3 lbs/h Steam Production
Residual oil	89	130
Natural gas	87	127
Western stoker/coal	82	120

Source: ICF, Inc. 1978. Economic Considerations in Industrial Boiler FuelChoice. Washington, D.C., p. II-6, II-9.

Capacity utilization is also a consideration in the economics of boiler fuel choice. It is the actual operational firing rate over the theoretical maximum firing rate. For example, the modeled boiler could theoretically operate 8,760 hours a year, but because of reduced load periods, scheduled maintenance, or unforeseen curtailments, it might only operate 5,000 hours per year. This would correspond to a capacity utilization rate of 57%. This rate determines the fuel use rate and the annual fuel cost, as well as variable plant O & M costs. Generally, industrial boiler systems have more idle periods than do utility boilers since boiler costs are usually only a small component of the finished product cost, steam needs may vary by season, working days per week, and shifts per day (ICF, 1979). The three studies indicate utilization rates of 50% to 65% (ICF, 1979; EEA, 1979; PEDCo, 1979). An EPA study reported utilization rates of between 40% and 55% (Batelle Columbus, 1975) and the Federal Energy Administration (FEA) found an average rate for boilers between 100 and 899 x 10^6Btu/h of 54% (Exxon, 1977). Value of 60% was used in the model.

FUEL CHARACTERISTICS

Fuel characteristics determine a major part of total plant life cycle costs. Fuel is valued for its heat content, usually expressed in Btus per pound. This has a direct on the hourly fuel requirements for the boiler and also for sizing of coal handling equipment. Because of pollution control requirements, the percent sulfur content by weight is an important indicator of pollution control expenditures. The ash content and total suspended particulate (TSP) rates are similarly important.

Table 5.4
Pertinent Fuel Characteristics

Fuel	S Content (%)	Ash Content	Btu Content	TSP Emission Rate	Lbs TSP/ 10^6Btu	Lbs SO2/ 10^6Btu
NGP Coal	.5	9.0	8,600/lb[a]	1316 lb/ton	6.88	1.18
Residual oil						
High	3.0	-	150,560/gal[b]	8lb/10^3 gal	0.053	3.14
Low	.3	-	146,430/gal[c]	8lb/10^3 gal	0.055	.31
Natural gas		-	1,027/ft^3	5-15 lb/$10^6 ft^3$	0.015	0.0006

Source: EPA, 1975. Compilation of Air Pollution Emission Factors, Pub AP-42. Triangle Park, N.C., p. 1.4-2.
a, Assumes undried coal; b, assumes gallon - 7.882 lbs;
c, assumes gallon - 7.571 lbs.

AIR POLLUTION CONTROL REGULATIONS

Emissions control of industrial boilers has a large impact on the economics of fuel choice because of the large increases in capital and O & M costs involved. The expense of such equipment often exceeds the price of a packaged boiler and sometimes even that of a field-erected unit (ICF, 1979). The level of control necessary can have a substantial effect on the annualized costs for coal and high-sulfur oil units. Because of its relative cleanliness, natural gas is not subject to regulation and the need for pollution control equipment (see Table 5.4). Since both state and federal laws are involved, the regulations can vary by boiler location. Finally, the combustor size can be a factor, since it figures prominently in the revised new source performance standards.

The regulations that influence the need for pollution control equipment are the Clean Air Act (1970) and its Amendments (1977), which gave EPA the authority to establish the National Ambient Air Quality Standards (NAAQS). States are required by these standards to adopt environmental regulations that insure compliance by industrial sources: (1) State Implementation Plans (SIPs) and (2) Nonattainment (NA/Prevention of Significant Deterioration (PSD).

SIPs are designed by each state to implement and maintain the standards within their borders. The NA and PSD rules are designed to upgrade or maintain air quality in areas in accordance with NAAQS. Nonattainment areas are those where NAAQS for specific pollutants are being exceeded. EPA has called for SIP revisions in these areas to insure reasonable progress toward air quality goals according to mandated schedules (1982 or 1987) (EEA, 1979). SIP strategies adopted for nonattainment areas vary from state to state and from case to case.

PSD rules are applied on a case-by-case basis to insure that economic development does not cause the air to deteriorate beyond specified levels. Depending on the emissions level and the class of the air quality area, new sources will be required to adopt best available control technology (BACT). For BACT application of the PSD standard, a major facility is defined as any with a firing rate of greater than 250×10^6 Btu/hr or one with the potential of emitting 250 or more tons of a pollutant annually. Alternately, this limit is 100 tons according to the NA rules.

The Clean Air Act also gave EPA the authority to create new source performance standards (NSPS), which are federal standards governing emissions from newly constructed sources. Current NSPS standards apply to all boilers coming on line between 1972 and 1985 that have firing rates greater than 250 x 10^6Btu/hr. For any unit, the NSPS is the binding regulation unless the applicable SIP is more stringent than NSPS. SIPs regulations apply to all boilers smaller than 250 x 10^6Btu/h. Table 5.5 summarizes current NSPS regulations. The regulation is specified as a ceiling emission rate that may not be exceeded (lbs/10^6Btu of fuel burned). SIPs limits on SO_2, total suspended particulate (TSP), and NO_x vary considerably by state both in stringency and method of expression (e.g., lbs pollutant/10^6Btu; lbs/lbx10^3 steam, boiler size, fuel, percent reduction).

Table 5.5
New Source Performance Standards

Fuel Type	Boiler Size (10^6Btu/hr)	Pollutant (lb/10^6Btu) SO_2	TSP	NO_x
Coal	10-250	SIPs	SIPs	SIPs
	250	1.2	.1	.7
Residual oil	10-250	SIPs	SIPs	SIPs
	250	.8	.1	.3
Distillate oil	10-250	SIPs	SIPs	SIPs
	250	.8	.1	.3
Natural gas	10-250	---	---	---
	250	---	---	.2

From EPA. October, 1980. Impact Analysis of Alternative New Source Performance Standards for Industrial Boilers: Economic Impacts. Research Triangle Park, N.C.

Boilers coming on line after 1985 will be subject to the revised new source performance standards (RNSPS), which will apply to all boilers with firing rates greater than 100 x 10^6Btu/h, called major fuel-burning installations (MFBIs). The actual EPA regulations have not been made final; therefore, the best assumption is that they will be similar to the revised new source performance standards regulations issued by EPA in 1978 for utilities. These standards are listed in Table 5.6.

Table 5.6
MFBI Revised New Source Performance Standards (lbs/10^6Btu)

Emission	Coal	Oil	Natural Gas
SO_2	1.2 lbs/90% reduction or if 90% reduction < = .6 lbs, then 70% reduction	.35	.20
TSP	.03	.03	--
NO_x	.05/.06[a]	.03	.015

Source: DOE. 1980. 1980 Annual Report to Congress, 1980. Service Report SR/1A/80-16.
a .05, subbituminous; .06. bituminous.

Pollution Control Requirements

Since 90% SO_2 reduction of NGP coal (1.18 lbs/10^6Btu) results in less than .6 lbs SO_2 MMBtu, only 70% SO_2 removal is required according to RNSPS. Since TSP emissions for NGP coal are high (6.88 lbs/10^6Btu), a removal system of 99.5% efficiency would be required to meet the standard. Often SIPs and interpretation of the nonattainment rules specify best available control technology standards for new MFBIs for

SO_2 so that 90% removal may be required even though the revised new source performance standards are not that stringent. EPA is also considering five new source performance standards options, one of which is more demanding than that listed in Table 5.6. The most severe, option 4, would extend the revised standards to boilers exceeding 50 x 10^6Btu/hr and also set an SO_2 floor of 2.0 lbs/10^6Btu/hr for smaller boilers. EPA estimates that even the most stringent of the options would result in a less than 1% product cost increase over all industries (EPA, 1980). The general effect on industrial boilers of the adoption of this standard would be to eliminate boiler undersizing in order to avoid revised new source performance standards regulations.

The modeled boiler (175 x 10^6Btu) qualifies as a major facility under all stated criteria (RNSPS, NA, PSD, and SIPs) because it potentially releases 904 tons of SO_2 and 5,273 tons of TSP per year at 100% capacity. The current political climate seems to favor leniency in future environmental standards for industry. Thus instead of BACT for NGP coal, the revised new source performance standards of Table 5.6 are assumed.

Industrial boilers are assumed to meet SO_2 revised new source performance standards and SIPs standards by the installation of wet or dry flue gas desulfurization equipment (FGD). Wet scrubbers would conform to BACT standards; dry lime scrubbers meeting the 70% SO_2 removal standard would fulfill the revised new source performance standards in Table 5.6. FGD equipment is assumed to be 90% reliable and 80% to 90% efficient (70% to 80% reduction). In addition, some FGD systems remove a significant portion of TSP. TSP reduction to compliance levels is accomplished using electrostatic precipitators or baghouse filter systems that are 99.5% efficient and 100% reliable (DOE, 1980). Oxides of nitrogen (NO_x) are controlled through combustion control modifications in the boilers. These costs will be included in the boiler pollution control capital costs.

Regulations Affecting Fuel Choice

Other federal regulations have implications for industrial boiler fuel choice. They are the Powerplant and Industrial Fuel Use Act (PIFUA), the Natural Gas Policy Act (NGPA), and the Energy Tax Act.

The PIFUA of 1978 prohibits the use of oil and gas in new boilers with a firing rate of 100 x 10^6Btu/h or greater. Exemptions from the act can be granted for reasons of cost, environmental constraint site resitrctions, or a temporary exemption for plants planning to use a synthetic fuel. An important aspect of the law is that the economic "test" that determines whether natural gas is prohibited in new industrial boilers is based on the price of equivalent medium sulfur oil and not on the price of the gas. For compliance, the natural gas used by industry must be priced as if it were oil (DOE, 1978). If adhered to, this policy would make coal-fired units less expensive than gas or oil.

The Natural Gas Policy Act of 1978 increases the price of natural gas to many industrial customers. It has two major impacts: well-head pricing controls and incremental pricing. The well-head regulation sets various maximum prices of natural gas to pipelines and provides for gradual escalation and eventual decontrol of natural gas.

The incremental pricing rule sets a price ceiling for use of natural gas in boilers. For 10 months, the gas price ceiling for nonexempt users is set at a price determined by DOE to be two standards deviations below the mean #6 residual fuel oil price. After 10 months, the price ceiling will automatically be set at a price two standard deviations below the distillate oil price. These provisions now apply to any boiler using more than 300 million cubic feet of gas per day (the equivalent of about 25 x 10^6Btu being burned during a 12-hour day). Typically, industrial users will have to pay $1.00 to $2.00 more per million Btus because of the Title II incremental pricing structure (DOE, 1980).

The Energy Tax Act (ETA) provides financial incentives for industry to burn alternative fuels in the place of oil and gas. The most important element is a 10% investment tax credit for boilers burning an alternative fuel. Oil and natural gas-fired boilers are denied the credit. Also, investments in alternative fuel burning ability can use accelerated depreciation methods for tax purposes, whereas oil and gas investments are required to use the straight line method. The provisions for the acts are due to expire and renewal is uncertain.

Cost Components

The direct costs of boiler systems include the cost of the boiler and various equipment items and the cost of labor and material required for installing the equipment and connecting the system. Land for the facility is also included as a direct cost. For coal and residual oil-fired systems, direct capital costs also include equipment and installation costs for pollution control equipment.

Indirect costs are those entailed in developing the overall facility, but not attributable to specific equipment. They include such items as construction and field expenses, engineering, construction fees, startup, performance tests and contingencies. Working capital, also included, represents the assets required to cover items needed for current operation of the facility--raw materials, in-process inventory, accounts receivable, and obligations for employee wages. Indirect costs are typically estimated at a set fraction of direct costs.

The three studies relied on price quotes from boiler manufacturers to arrive at direct cost information. However, each study modeled different sized boilers, making it necessary to interpolate by using two boiler sizes for each study to arrive at a value for a boiler with a firing rate of 175×10^6 Btu. By averaging oversized and undersized boilers, it was possible to approximate scale factors. For the PEDCo calculations, changes were made to offset the cost of the stoker used in our model, which was lower than the cost of the pulverizer they modeled. Also, it was necessary to inflate all dollar values to 1980 dollars using the Producer Price Index for industrial boiler equipment. Cost data for coal, oil, and natural gas units are presented. Table 5.7 shows the direct costs for the modeled boiler.

Table 5.7
Direct Capital Costs for a 175 x 10^6 Btu/hr Industrial Boiler (\$1980 x 10^6)

Study	Coal[a]	Low-S Oil	High-S Oil	Natural Gas
ICF	6.22	2.26	2.26	1.92
EEA	4.89	2.02	2.02	1.86
PEDCo	9.12	1.57	1.58	1.51

Source: ICF, Inc. 1978. Economic Considerations in Industrial Boiler Fuel Choice. Appendix A. Washington, D.C.; DOE/EIA. 1978. An Industrial Boiler Fuel Modeling Approach. DOE/EIA-0183/8; PEDCo Environmental, Inc. 1979. Background Study in Support of New Source Performance Standards for Industrial Boilers. Cincinnati, OH.

PEDCo Environmental, March, 1979. Background Study in Support of New Source Performance Standards for Industrial Boilers,

Significant disparities exist between the various estimates for direct capital costs. The PEDCo estimates for oil and gas are lower than those of EEA and ICF, whereas their costs for coal boilers are significantly higher than the EEA or ICF projections. Table 5.8 lists the indirect capital cost information for the modeled boiler.

Table 5.8
Indirect Capital Costs for a 175 10^6 Btu/h Industrial Boiler (\$1980 x 10^6)

Study	Coal[a]	Low-S Oil	High-S Oil	Natural Gas
ICF	2.31	1.27	1.18	.75
EEA	2.41	1.06	1.06	.87
PEDCo	7.32	.85	.80	.76

From references cited for Table 5.7.
a No pollution control

Since indirect capital costs are normally broken down in categories that are percentages of the direct capital expenses, the information in Table 5.8 is not surprising. Typically, indirect capital costs are about 30% to 50% of direct costs (PEDCo, 1979).

Given current environmental regulations, it is important to incorporate direct and indirect capital expenses for pollution control equipment for industrial boilers. Because the technology for pollution control is fairly new for industrial-sized installations, such information is not widely available. Several studies were surveyed to reach a consensus. It is assumed that 70% removal of SO_2 will be required for coal and that a dry lime scrubbing system with a baghouse filtration system for 99% TSP removal is used. Table 5.9 lists both direct and indirect capital costs for the modeled boiler.

Table 5.9
Estimated Pollution Control Costs for a 175×10^6 Btu/h Boiler
Firing NGP Coal ($\$1980 \times 10^6$)

Study	Direct Capital	Indirect Capital (40% of direct)
EEA	3.67	1.47
ICF	3.97	1.59
Radian	2.67	1.07
TVA	3.19	1.28
Mean	3.38	1.35

Source: Ball, J.G. 1980. FGD Capital Investment/Operating Costs. Durham, N.C.: Radian Corp.; DOE/EIA. Sept.1978. An Industrial Boiler Fuel Modeling Approach. DOE/EIA 0183/8. Washington, D.C.

The range in estimates is not large (standard deviation = $\$.57 \times 10^6$), so it was decided to use a mean cost for both direct and indirect estimates. Only two of the studies above listed the expenses of pollution control for a residual high-sulfur oil boiler.

Table 5.10
Estimated Pollution Control Costs for a 175 x 10^6 Btu/h Boiler Firing High-Sulfur Residual Oil ($1980 x 10^6)[a]

Study	Direct Capital	Indirect Capital (40% of direct)
EEA	3.67	1.47
ICF	2.71	1.08
Mean	3.19	1.28

Source: Energy and Environmental Analysis. 1980. Industrial Fuel Choice Analysis Model. Arlington, Va.: EPA, Vol. 2, p. H-38; ICF, Inc. 1978. Economic Considerations in Industrial Boiler Fuel Choice. Washington, D.C., pp. A-12, A-19.

After estimating all direct and indirect capital costs by fuel type and pollution control costs, it is possible to aggregate total capital cost data. This represents the total anticipated capital investment necessary for the modeled boiler.

Table 5.11
Total Capital Costs for a 175 x 10^6 Btu/h Industrial Boiler ($1980 x 10^6)

Study	Coal[a]	Low-S Oil	High-S Oil	Natural Gas
ICF	13.26	3.53	7.91	2.67
EEA	12.03	3.08	7.55	2.73
PEDCo	21.17	2.42	6.85	2.27
Mean	15.49	3.01	7.44	2.56

[a]4.73 added to all coal plants from mean of Table 5.9.

[b]4.47 added to all high-sulfur oil plants from mean of Table 5.10.

Operation and maintenance costs are expenses incurred for the labor and materials necessary to continue operations on an annual basis. These costs do not include annual fuel costs, which are covered later.

O & M costs are considered to consist of five components: (1) staff and labor force, (2) maintenance equipment and repairs, (3) pollutant transport and disposal, (4) supplies, and (5) general and administrative expenses. These components are represented in the form of fixed and variable components, the variable constituents being those that are altered by degree of plant capacity utilization. Unless otherwise noted, O & M variable costs are assumed to follow a fixed plant capacity utilization of 60%. However, these expenses are broken into two distinct areas: costs attributable to steam plant operation and those associated with pollution control equipment. This classification allows important sensitivity analysis of compliance variations with applicable environmental regulations. All costs are presented in 1980 dollars. Plant and payroll overhead is estimated at a fixed percentage (normally 25% to 30%) of direct labor costs.

Staff expenses comprise the largest single component in the O & M costs for a boiler plant. Coal systems, especially those with FGD systems installed, require numerous skilled workers for reliable plant operation. The O & M expenses for coal-fired boilers demonstrate significant economies of scale (ICF, 1979).

Table 5.12 presents a fractional breakdown of the O & M categories of typical boilers.

Table 5.12
ICF Annual O & M Breakdown for a 175 x 10^6Btu Boiler (\$1980 x 10^6)[a]

	High-S Coal Plant	High-S Coal PC	Residual Oil Plant	Residual Oil PC	Natural Gas Plant	Natural Gas PC
Staff	.35	.11	.21	.06	.18	.00
Maintenance materials	.09	.05	.04	.02	.03	.00
Pollutant disposal	0	.09	.00	.05	.00	.00
Supplies	.04	.26	.02	.14	.01	.00
G & A	.05	.04	.03	.02	.02	.00
Total	.53	.44	.30	.29	.24	.00

Source: ICF, Inc. 1978. Economic Considerations in Industrial Boiler Fuel Choice. Washington, D.C., p. II-85; Congressional Budget Office, p. 31

[a]Assumes 60% capacity utilization.

Observe that pollution control costs more than double the O & M costs for coal. Table 5.13 summarizes the pollution control O & M costs estimated for the model boiler by various studies.

Table 5.13
Estimated O & M Pollution Control Costs for (in \$$10^6$) a 175 x 10^6Btu/h Boiler System Firing NGP Coal[a]

Study	Annual O & M
EEA	.66
Radian	.94
TVA	.53
ICF	.93
Mean	.77

Source: Ball, J.G. 1980. FGD Capital Investment/Operating Costs. Durham, N.C.: Radian Corp.; DOE/EIA. Sept. 1978. An Industrial Boiler Fuel Modeling Approach, DOE/EIA D183/8.

Table 5.14 summarizes O & M costs for the modeled boiler as estimated by each of the three primary studies. Note the wide range of results.

Table 5.14
Annual O & M Costs for a 175 MMBtu/h Industrial Boiler ($1980 x 10^6)

Study	NGP Coal	P/C	Coal P/C	Low-S Oil	High-S Oil P/C	Natural Gas
ICF	.53	.44	.97	.30	.59	.24
EEA	1.71	.66	2.47	1.07	1.36	1.07
PEDCo	1.91	.77[a]	2.68	2.14	2.43	2.14
Mean	1.38	.77[a]	2.04	1.17	1.46	1.15

Source: ICF, Inc. 1978. Economic Considerations. Washington, D.C., pp. A-11, A-13, A014, II-35; EEA. 1980. Industrial Fuel Choice Analysis Model. Arlington, Va.: EPA, pp. F-13, F-10; PEDCo. 1979. Background Study, pp. G-53, 37, 47, 52, 54.

[a]Mean from Table 5.13.

Fuel Costs

The fuel costs for industrial plant operation are very important to the fuel choice modeled. This includes all expenses related to extraction, processing and the delivery of fuel to the steam plant. The fuel types considered in this analysis are Northern Great Plains coal, residual and distillate fuel oil and natural gas. Their characteristics have been described in Table 5.4.

All fuel costs are enumerated in the analysis in terms of 1980 dollars per 10^6 Btus of heat content. The annual fuel consumption is estimated based on a 175 x 10^6 Btu/hr boiler with a 60% capacity utilization rate. The product of fuel costs and the consumption rate yields an annual fuel component cost expressed in millions of 1980 dollars.

From the previous discussion we observe the forceful effect of fuel prices and their effect on boiler fuel choice. Since the economic analysis typically involves a study of the costs over the life of the facility, assumptions concerning future fuel price behavior is particularly important. In the following sections determinants of future fuel prices peculiar to each fuel is examined.

COAL

Coal has the lowest price per million Btus among the considered fuels. Its cost is divided into two major components -- freight on board (F.O.B.) mine costs and transportation costs. The average F.O.B. mine costs for industrial contracts in the survey conducted was $10.95 for NGP coal (Std. Dev.=$1.92). This survey is discussed in detail in Chapter 7. This cost is about 23% greater than the average utility coal purchase in 1980 of $8.90 per ton since smaller short term contracts are necessary. Some real annual coal cost increases can be expected in the future due to real cost increases for mining labor and reserve depletion allowances. ICF Inc. (1979) estimates this to be only about 1% per year over the thirty year plant lifetime for Western coals. A study of the average cost per ton of NGP coal from the period 1960 to 1980 found only a real rate of annual increase in price of .57% per year. As a result this assumption appears conservative.

Coal has significant transportation costs from mine to burning facility. The most often used method of coal transport is to use unit trains as developed by the utilities. However, few if any industrial sites require the coal volume necessary to use unit trains. The average tons per year was only 56,780 for industrial contracts in the survey whereas utility contracts are up to 100 times this amount.

Consequently, they have to purchase multiple or single car rates which are double or more that of the unit train rates (ICF, 1978). Such rates increase in direct proportion to the distance the load must travel from mine to plant. As a result most of the coal from the NGP fields are trucked to their destination. The average cost for this transport was \$9.80 (Std. Dev.=\$5.81) so that transportation formed 47% of the delivered costs of the coal which was \$20.75 per ton in the survey. A linear regression was performed on the relationship between the distance of shipment and the resulting cost adjusted to 1980 dollars. The result was:

$$\text{TransCost} = \$2.66 + \$.043\ (\text{Straightline Air Miles})$$

$$R^2 = .990$$

$$N = 10$$

The fixed cost component is more than twice that encountered in utility sales and the variable cost is slightly less than three times as much. This will have the effect of restricting industrial use to near minemouth generation. Furthermore, these costs are expected to escalate in real terms. In Duffield et.al. (1982) Harr determined that a 3.8% real escalation rate for the base case analysis in utility contracts was appropriate. In this analysis, a real escalation rate of 3% is used for the first ten years based on expectations concerning railroad deregulation (DOE/EIA-0399, 1983). Subsequent to this period, a 2% real rate is used.

Assuming 17 million Btus per ton (8,500 Btu/lb) NGP coal cost only \$1.22 per million Btu as delivered to Montana industry in 1980. This was only 46% that of natural gas costs to industry in that year (\$2.62 per 10^6 Btu), 36% that of heavy fuel oil costs (\$3.43) and only 20% of distillate fuel oil costs (\$6.10) (DOE/EIA-0376, 1983). Furthermore, this disparity is expected to continue and perhaps widen as natural gas is deregulated by 1985 (Walsh, 1983).

OIL

Delivered oil prices to industry are much more uncertain than those of coal because of the volatile nature of the world petroleum market. Because of this uncertainty, it is necessary to examine a range of possible fuel price projections.

Since oil prices are not solely dictated by extraction and transportation costs, but also by scarcity and cartel oil pricing, it is difficult to develop a fuel price escalation rate with any degree of certainty. The 1970s were marked by wild fluctuations in delivered oil prices to industry. The DOE Midterm Energy Forecasting System has consistently incorrectly estimated world oil prices. In 1979 an international oil price of \$32 per barrel was predicted by 1985 which was subsequently passed in 1980! Currently, (Fall, 1983), a world oil surplus exists which has slightly depressed world oil prices. However, this surplus is apt to disappear with international economic recovery (International Energy Agency, 1983).

All these factors conspire to make the future price of oil exceedingly uncertain. An examination of oil prices delivered to Montana industry from 1960 to 1980 found the average annual real fuel price escalation rate for distillate oil to be 4.11% per year; and 3.00% for residual fuel oil (EIA-0376, 1983, Steele, 1980). However, the period observed was one of rapid change, a study of well head prices from 1950 to 1978 found the real rate of increase to be about half this -- 1.89% per year. Therefore, a rate of 2% real escalation in oil prices is used in the analysis as the base case. Sensitivity analysis for this estimate is important, however.

NATURAL GAS

The policy mechanisms affecting natural gas pricing have been discussed earlier. However, these pricing mechanisms are nearing expiration which lends uncertainty to future natural gas prices. Historically, gas prices have incrased more rapidly in real terms than any of the other studied fuels as shown in Table 5.15.

Table 5.15
Montana Historical Industrial Energy Prices
Constant $1980 per 10^6 Btus

Fuel	1960	1970	1975	1980	APGR
Coal	.575	.212	.423	.644	.5%
N. Gas	.722	.601	1.292	2.620	6.4%
R. Oil	1.833	1.552	3.550	3.430	3.0%
D. Oil	2.683	2.367	3.720	6.101	4.1%

Sources: EIA, 1983. Energy Price and Expenditures Data Report, DOE/EIA-0376, Washington, D.C.
Steele, L., 1980. Historical Energy Statistics, DNRC, Energy Division, Helena, MT.

As seen in the table, the rate of price increases for natural gas has been very rapid during the 1970s. However, it is very likely that much of this increase has been due to the relaxation of pricing mechanisms that have historically held this valuable fuel to less than its true market price. Furthermore, it is unlikely that such a trend will continue, although many analysts expect signficant increases in 1985 when deregulation is complete (Walsh, 1983). The enforcement of the PIFUA may have important consequences for future gas use by industry since it is based on increasing the price of natural gas to that of residual fuel oil based on equivalent heat content. Of course this in turn heightens the uncertainty of natural gas prices since they are apt to be tied to the fluctuating price of world fuel oil. As a result, DOE has forecasted that industrial demand for natural gas will continue to be soft (DOE, 1982) and its market share of the industrial demand for energy is not forecasted to change appreciably.

On an economic basis, natural gas is the primary competitor with coal as an industrial boiler fuel. Although coal has always been the least cost fuel for such applications on a heat basis, this does not account for the very significant disparity between plant cost. An industrial coal boiler with required pollution control equipment may cost ten times as much as a comparable gas boiler. As seen in Table 5.15, the cost of a million Btus of gas heat was relatively cheap until after 1970. This accounts for the preference of natural gas over coal as an industrial fuel during this period.

Future natural gas prices are exceedingly difficult to predict. Currently there is a gas surplus which has slightly depressed price. However, complete deregulation in 1985 and enforcement of the PIFUA that will increase gas prices to that of residual fuel oil makes short term increases likely (Walsh, 1983). In the modeling procedure, a real escalation rate of 4% is used over the short term (10 years) with 2% being used over the long term as the base case parameters. Clearly a major caveat in this assessment is the enforcement of the PIFUA and NGPA and continuation of this legislation.

The Modeling Approach

The methodology for comparing firm investment decisions in this investigation is to evaluate the present value of the project costs over its expected lifetime. This is accomplished by representing the present value of the cost stream as a series of real annuities assumed to simply escalate at the rate of inflation. These costs are the sum of the annual levelized capital costs, the operation and maintenance costs and the fuel costs. These annuities are readily comparable in terms of the relevant fuel choice. The various factors involved in this analysis are complex and repetitive in nature. Therefore, a computer code was formed to facilitate the analysis. A listing is contained in Appendix A.

CAPITAL CHARGE RATE

Capital costs have been estimated for steam plants according to the combusted fuel. The values used are the means shown in Table 5.11. To translate these capital costs into real annuities a capital charge rate must be estimated. This cost represents the investments necessary to design, develop and erect the boiler. The charge rate is an analytic construct which translates all the lifetime capital expenditures into a constant stream of annual fixed costs. The rate includes depreciation, interest on debt, return on equity and other charges associated with capital such as state and federal taxes, insurance and administrative costs. The present value of the annuity is equal to the present value of the actual stream of capital charges, stipulated in real terms with inflation subtracted from the assessment. This insures that comparisons of annuities are equivalent comparisons of present values.

The weighted cost of capital is used as the appropriate discount rate for these calculations. It is the average after tax cost of debt and equity according to the firm's capital composition. A representative financial structure was estimated at 30% debt and 70% equity (Moody's, 1976). Other assumptions include a 10% investment tax credit, a 52% marginal state and federal tax rate, a 6% annual inflation rate and a project life of thirty years (Multari, 1981). These assumptions are detailed below in Table 5.16:

Table 5.16
Financial Assumptions in Fuel Choice Model

Time Horizon = 30 years
Debt Ratio = .3
Preferred Stock Ratio = .2
Common Stock Ratio = .5
Nominal Debt Cost = 9.5%
Nominal Preferred Stock Cost = 10%
Nominal Common Stock Cost = 13.5%
Inflation = 6%
Insurance Rate = 2%
Marginal Federal Tax Rate = 45%
Marginal State Tax Rate = 5%
Marginal Property Tax Rate = 2.5%
Investment Tax Credit = 10%
Depreciation = Acclerated Straightline (2/3s book life)

Other assumptions necessary for this modeling procedure includes the boiler firing rate which is set at a 175 million Btus input per hour and the capacity utilization rate, set at 60%. The nominal weighted cost of capital is then 11.07% or 3.7% in real terms. In order to calculate the Fixed Charge Rate (FCR) a capital recovery factor must be estimated:

$$CRF = \frac{RCC * (1+RCC)\hat{}N}{[(1+RCC)\hat{}N-1]}$$

Where: RCC = Real Cost of Capital
N = Project life (30 years)
CRF = .0672

To calculate depreciation, a sinking fund factor is estimated. Its use provides a fund at the end of the project life equal to the original capital investment. A modified capital recovery factor, CRFb is also estimated:

$$SFF = \frac{RCC}{(1+RCC)^N - 1}$$

The SFF = .0143

The levelized income tax rate is calculated as:

$$LIC = (CRFb - SLD) * 1 - \frac{\text{Debt Ratio} * \text{Debt Cost}}{RCC} * \frac{ITX}{1-ITX}$$

Where: SLD = straight line depreciation (1/project life)
RCC = real cost of capital
ITX = marginal state and federal tax rate

The assumed levelized accelerated depreciation is calculated:

$$ADPR = \frac{[2 * CRFb * (n - 1/CRFb)]}{n\ (n+1) * RCC}$$

Where: n = tax life (2/3s of the project life; 20 years)
ADPR = .0575

$$\text{Levelized ADPR} = (ADPR-SLD) * 1 - \frac{ITX * \text{Debt Ratio} * \text{Debt Cost}}{RCC} * \frac{ITX}{1-ITX}$$

The levelized investment tax credit is estimated:

$$LEITXCR = \frac{ITCR}{1-ITX} * \frac{[CRFb/1+RCC) - (ITX * \text{Debt Ratio} * \text{Debt Cost})]}{RCC} * (CRFb/\ (1+RCC) - 1/N)]$$

Where: ITCR = investment tax credit, .10
LRITXCR = .0154

The fixed charge rate is simply the sum of the cost components less the credits for investment tax credit and depreciation. This is summarized in Table 5.17.

Table 5.17
Real Levelized Fixed Charge Rate

Component	Per Cent
Weighted Real Cost of Capital	5.28%
Sinking Fund Depreciation	1.43
Insurance and Property Taxes	2.00
Income Taxes	4.33
Investment Tax Credit Factor	(1.54)
Accelerated Depreciation Factor	(2.41)
Total	9.09%

VARIABLE COSTS

Variable costs in the analysis consist of two components -- operation and maintenance costs, coal transportation costs and fuel costs. Both vary considerably with the capacity utilization rate of the plant which is set to 60% in the base case analysis. Also, based on historical behavior we expect that fuel prices may escalate in real terms. Moreover, Harr in Duffield et.al. (1982) has shown that historically operation and maintenance costs have also escalated in real terms although only at about 1% annually while the best estimate for future increase in coal transportation costs was significant at 3.8%. In the analysis, these variable costs are set to the expected values in 1980 at a 60% utilization rate. They are specified in real terms so that adjustments for inflation are unnecessary. The procedure for estimating this escalation effect for the variable cost components is shown below. It results in a multiplicative levelization factor for these costs:

$$UPWe = CRF * \frac{(1+e)}{(1+RCC)} \quad 1 - \frac{(1+e)N}{(1+RCC)}$$

Where: e = real price escalation rate (0-4%)

In the analysis, the escalation rates are specified for the short term (first ten years of the study) and a long term rate for the remainder of the analysis period. Since the variable costs form the largest annualized component, the specification of these escalation rates is particularly important in the analysis. They are summarized in Table 5.18 below:

Table 5.18
Base Case Real Price Escalation Rates

Component	Short term Rate	Long term Rate
Operation and Maintenance	1.0%	1.0%
Transportation Costs	3.0%	2.0%
Coal F.O.B. prices	1.0%	1.0%
Residual Oil prices	2.0%	2.0%
Distillate Oil prices	2.0%	2.0%
Natural Gas prices	4.0%	2.0%

PLANT SCALE FACTOR

Another "variable" cost is the expense of erecting the modeled boiler. Generally in engineering projects economies of scale are observed. Thus it would not cost twice as much to purchase and install a boiler of twice the capacity of the one modeled (350 x 10^6 Btu/hr firing rate). On the other hand, it would cost more than half as much to install one of half the capacity (88 x 10^6 Btus/hr). As depicted, unit costs decrease as the size of the system increases. This is usually accounted for in engineering practice through use of a power equation to represent the relationship between investment and capacity:

$$I = KC^n$$

Where: I = investment
C = capacity
K = reference capacity
n = scale factor

ICF (1978) recommends scale factors of .65 for prepackaged natural gas and distillate oil units and .75 for coal and residual oil units that will require pollution control equipment. Thus, if the coal steam plant size is doubled from the reference case, it would cost 68% more than the base unit. Specification of this value will allow study of the effects of scale in the fuel choice decision.

FUEL SPECIFIC STEAM PLANT EFFICIENCY

Different fuels used in a boiler with a similar input firing rate will have different outputs in terms of steam production. Ultimately, this is the commodity on which the firm is attempting to reduce costs in production. In the model this is accomplished easily through modification of the heat contents of the various fuels according to the efficiency penalty factor for that fuel. These are taken directly from Table 5.3. The efficiency factors are .89 for oil combustion, .87 for natural gas and .82 for coal in a stoker system (ICF, 1979).

COAL TRANSPORTATION COSTS

This value is very important in the analysis of interfuel substitution potential for coal. It is specified according to the fixed and variable cost components shown in the regression developed from the survey results. These values are then modified by the appropriate escalation factor. This tends to be a critical variable in the assessment since industrial transport costs are almost triple that of utility unit train rates. In the reference case, the coal plant is assumed to be sited one hundred miles from minemouth. In later sensitivity study, coal's competitive equilibrium distance will be estimated against the other fuels and against competing western coals.

MODEL CALCULATION PROCEDURE

The model first estimates fixed charge rate and variable cost escalation factors. The base 1980 values are then multiplied by these levelization factors. The plant cost is calculated based on the plant firing rate and base operation and maintenance expenses are computed according to the capacity utilization and firing rate. The amount of fuel for each type is computed based on the firing rate, utilization rate and the efficiency factors. The costs of the various fuel are taken from the 1980 base values in Table 5.16 with appropriate transportation costs added to coal. The various costs of annual operation are then summed for a levelized esimate for each fuel. The annualized costs for the various fuels is then examined for the least cost choice.

Results

The reference case model results are presented in Table 5.19:

Table 5.19
Annualized Costs for a 175 x 10^6 Btu/hr
Industrial Boiler $1980 x 10^6

Component	NGP Coal	Nat. Gas	Res. Oil	Dis. Oil
Capital	$1.41	$ .23	$ .68	$ .27
O & M	2.30	1.30	1.65	1.32
Fuel	1.41	3.72	4.54	8.08
Total	5.12	5.25	6.87	9.66

From this summary it is seen that coal is only marginally least cost in the market area. Distillate oil is not competitive due to the very high fuel costs. Residual fuel oil is not competitive due to additional pollution control costs. With coal and natural gas so competitive, sensitivity analysis is required.

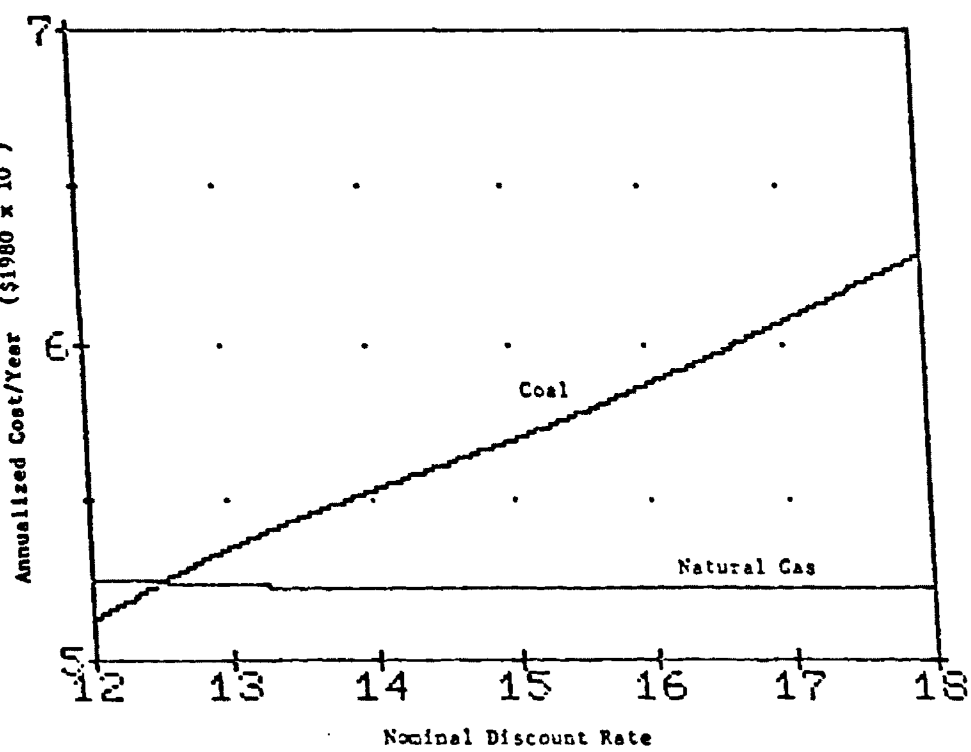
Sensitivity Analysis

The following examination studies the model sensitivity to the variables that might affect the investment decision. These include the real cost of capital, the macroeconomic inflation rate, capacity utilization, economies of scale, payback time horizon and cost of environmental compliance.

The cost of capital is very sensitive to the prime lending rate which is in turn dependent on many exogneous political and economic influences. In the model the real weighted cost of capital excluding inflation is 5.3%. In Table 5.20 and Figure 5.1 variations on annual-

Figure 5.1

SENSITIVITY OF ANNUALIZED COAL AND GAS COSTS TO NOMINAL DISCOUNT RATE



ized cost of the various boiler fuel configurations due to varying discount rates is studied.

Table 5.20
Sensitivity of Annualized Costs to Nominal Cost of Capital

Real Cost of Capital	NGP Coal	Nat. Gas	Res. Oil	Dis. Oil
Ref. 12.0%	$5.12	$5.25	$6.87	$9.66
13.0	5.35	5.23	6.90	9.57
15.0	5.69	5.22	6.97	9.46
18.0	6.28	5.22	7.13	9.35

Coal annualized costs show strong sensitivity to the appropriate cost of capital. At a real cost of capital of 6% natural gas is roughly equivalent and is preferred at higher rates.

In a similar fashion, Table 5.21 tests the model sensitivity to the inflation rate:

Table 5.21
Sensitivity of Annualized Cost to Fuel Escalation Rate

Escal. Rate	NGP Coal	Nat. Gas	Res. Oil	Dis. Oil
Ref.[1]	$5.12	$5.25	$6.87	$9.66
No Escal.	4.66	4.30	5.68	7.75

1 = Natural Gas = 4.0% first ten years, 2.0% last 20 years
Coal = 1.0%, 1.0%, Res. Oil = 2.0%, 2.0%, Dist. Oil = 2.0%, 2.0%

If it assumed that fuel and labor costs will remain constant during the analysis period, the competitiveness of industrial steam coal is seriously reduced. Here it is assumed that transportation costs will escalate at 3% per year for the short term and remain constant thereafter.

Table 5.22
Sensitivity of Annualized Costs to Inflation Rate

Inflation Rate	NGP Coal	Nat. Gas	Res. Oil	Dis. Oil
6.0% (Ref.)	$5.12	$5.25	$6.87	$9.66
8.0%	4.89	5.29	6.86	9.84
10.0%	4.70	5.35	6.90	10.04

As shown here, increased inflation is beneficial to the coal investment in that the cost of capital is somewhat reduced. Inflation tends to increase the cost of combusting petroleum fuels due to its effect in reducing the amount of discounting of future fuel cost streams.

Table 5.23
Sensitivity of Annualized Costs to Capacity Utilization Rate

CU Rate	NGP Coal	Nat. Gas	Res. Oil	Dis. Oil
Ref. 60%	$5.12	$5.25	$6.87	$9.66
20%	4.18	2.77	3.84	4.28
30%	4.42	3.39	4.59	5.63
40%	4.65	4.01	5.35	6.97
50%	4.89	4.63	6.10	8.31
70%	5.36	5.87	7.62	11.01
80%	5.59	6.49	8.37	12.35

The relative insensitivity of coal's annual costs to fuel expenses increases its attractiveness as the rate of use increases. As shown in Figure 5.2 low utilization rates strongly favors natural gas.

Figure 5.2

SENSITIVITY OF ANNUALIZED COAL AND GAS COSTS TO CAPACITY UTILIZATION RATE

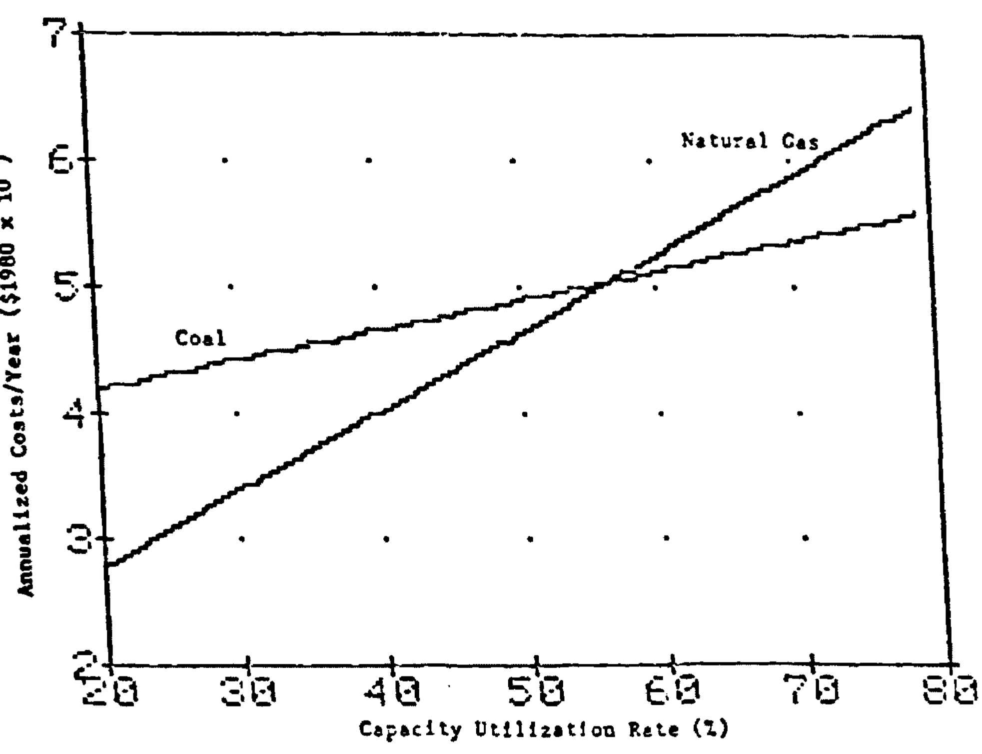


Table 5.24
Sensitivity of Annualized Costs to Boiler Size

Firing Rate	NGP Coal	Nat. Gas	Res. Oil	Dis. Oil
175 (Ref)	$5.12	$5.25	$6.87	$9.66
50	1.85	1.74	2.20	3.01
100	3.25	3.19	4.12	5.72
200	5.71	5.92	7.75	10.96
300	7.98	8.54	11.26	16.10
400	10.12	11.11	14.69	21.17

The competitiveness of the coal fired units increases with the size of the firing unit. Sizes under that of the modeled boiler tend to favor natural gas units as seen in Figure 5.3.

Table 5.25
Annualized Costs as a Function of Time Horizon

Year	NGP Coal	Nat. Gas	Res. Oil	Dis. Oil
30 (Ref)	$5.12	$5.25	$6.87	$9.66
3	14.60	14.65	18.63	25.80
5	9.50	9.29	11.89	16.34
7	7.33	7.00	9.01	12.29
10	5.71	5.29	6.87	9.28
15	5.20	4.96	6.47	8.86
20	5.12	5.04	6.58	9.13
25	5.11	5.14	6.72	9.40

This is one of the most sensitive variables. Coal does not become the least cost fuel until a time horizon of over twenty years is considered (see Figure 5.4). This is important since many firms are attempting to recover their capital in much shorter periods than the

Figure 5.3

SENSITIVITY OF COAL AND GAS ANNUALIZED COSTS TO BOILER SIZE

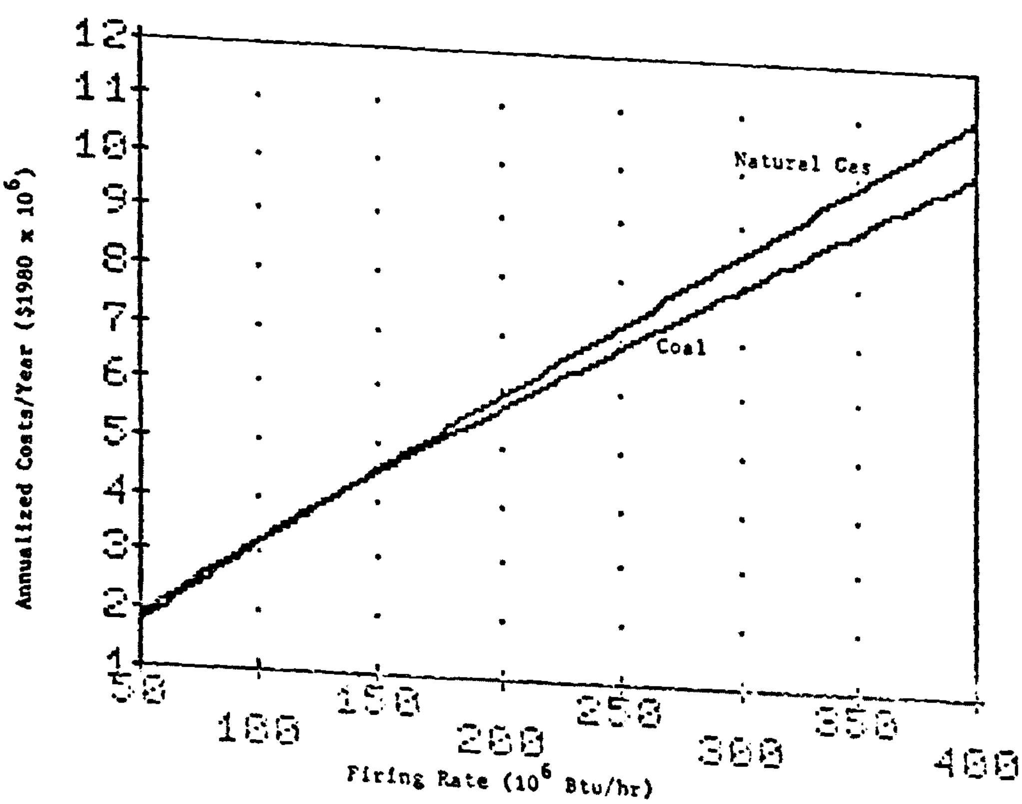
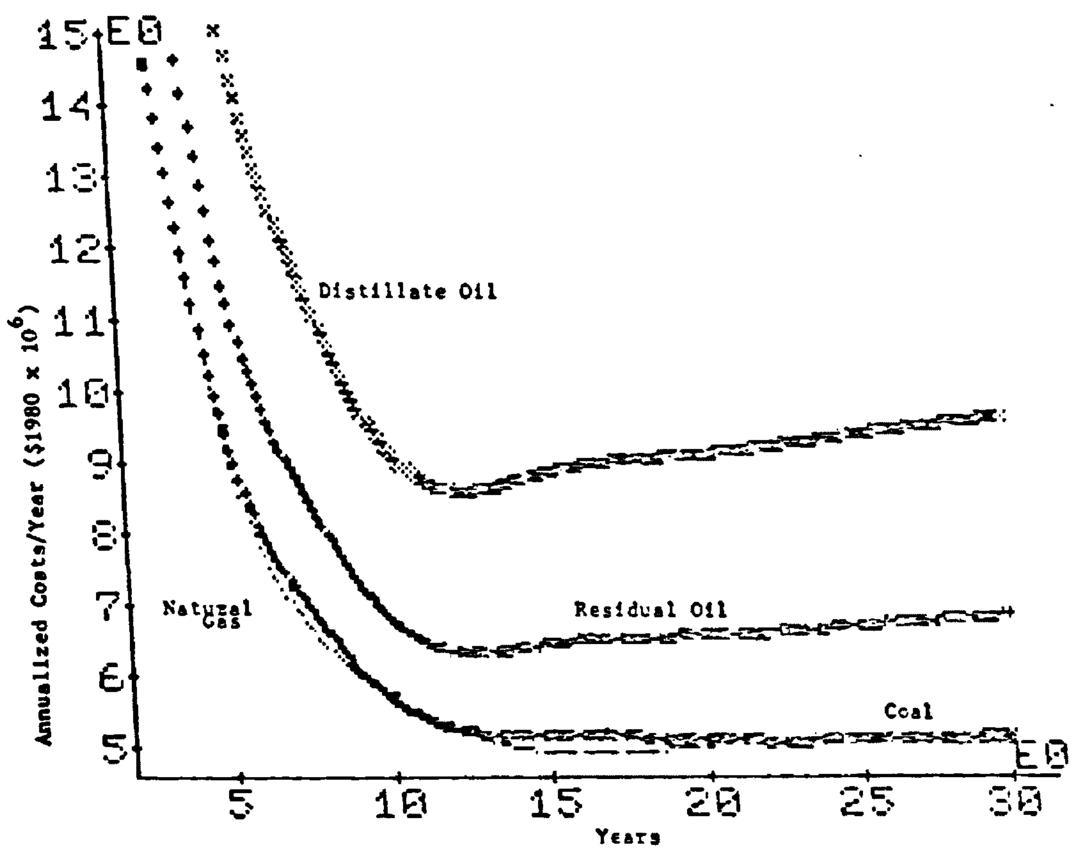


Figure 5.4

SENSITIVITY OF ANNUALIZED FUEL COSTS TO TIME HORIZON



project book life. In such cases, natural gas would be the preferred fuel.

Table 5.26
Sensitivity of Annualized Costs to Environmental Compliance

Scenario	NGP Coal	Nat. Gas	Res. Oil	Dis. Oil
Ref. Case	$5.12	$5.25	$6.87	$9.66
No Pol. Control	3.95	5.25	6.13	9.66

This analysis is more illustrative than it is practical. The cost of environmental pollution control equipment is significant enough to spoil the economics for industrial coal use.

Industrial Coal Market Size

The following two tables detail the market size of the NGP industrial coal market against other fuels and against other coal sources in the West. This is based on the distance that NGP coal can be shipped from source to the point that it reaches cost equilibrium with other fuels or other coals. Against other fuels, the shape of this market is circular. Against other Western coals which also have transportation costs, the market shapes are bounded hyperbolas.

In general, the interfuel competition comes in earlier than does competition with other coals. Exceptions may include the South Wyoming and Colorado coals.

Table 5.27
Sensitivity of Annualized Coal Costs to Transportation Distance

Distance (Miles)		Cost
Ref.	100	$5.12
	10	4.79
	20	4.83
	40	4.90
	60	4.97
	150	5.31
	200	5.49
	300	5.86

Annualized coal costs are relatively sensitive to the distance to the mine so that this might be a major consideration in the fuel choice decision. However, it must be remembered that the distance to the industrial markets may be equally as important.

Table 5.28
Equilibrium Distance for Coal Against Other Fuels

Fuel	Distance
Nat. Gas	130
Res. Oil	570
Dist. Oil	1340

Obviously, industrial coal cannot be shipped far against natural gas before that fuel becomes more economically attractive. This result is empirically borne out by the survey responses.

Table 5.29
Western Coal Characteristics

Coal Source	Heat Content (lb)	$FOB/ton	Dist-NGP
NGP-Gillette, WY	8,600	$ 11.00	0
Centralia, IL	10,500	26.00	506
Centralia, WA	8,100	34.00	694
Superior, WY	10,500	21.00	154
Hayden, CO	10,700	22.00	172
Huntington, UT	11,500	25.00	248
Emory, TX	6,300	10.00	578

Table 5.30

Price Equilibrium Distance Against Western Coals

Coal Source	Distance
Illinois	510
Wyoming	150
Colorado	170
New Mexico	300
Utah	250
Texas	580
Washington	700

This equilibrium distance depicts the distance NGP coal can be shipped and still remain competitive with other coals. The economics of the natural gas choice dwarfs most of these distances except in the case of Wyoming, Utah and Colorado coals.

An Uncertainty Analysis

A more formal uncertainty analysis is considered here (Multari, 1981). The sensitivity analysis has demonstrated that coals cost advantage in the base case is quite small and very sensitive to a number of operational variables that are beyond the control of the decision making firm. Below an example is presented typifing the logic of a real world decision.

A paper products firm is in need of a new production plant with boiler facilities. They are uncertain of three important variables that will figure in their decision -- the favorability of the macro-economic environment, how fuel prices might change over the project life and how high the capacity utilization rate for the plant will be. The firm is locating 100 miles from the mine and would like to install a coal or natural gas boiler with a 175 million Btu firing rate. Financial analysts for the company have been asked to estimate probabilities for the various uncertain elements. Based on best information, the analysts feel there is a two third chance that the economic climate will be favorable. This is expected to consist of a 6% inflation with a 12% nominal cost of capital. Since a favorable economy is often indicative of lower fuel price excalation rates they believe that under this scenario there will be a 75% chance of constant natural gas prices, but with a 75% chance of a high average 70% capacity utilization rate for the boiler over its useful life.

On the other hand, there is a one in three chance of an unfavorable economic climate (18% nominal cost of capital, 10% inflation).

Under this scenario, the analysts believe natural gas price escalation is probable. However, because of possible recession and reduction in demand for their product, there is a 75% chance that the utilization rate will only be 50% in this case.

The expected payoff of these cumulative uncertainties can be represented as a probability tree as illustrated below in Figure 5.5. As shown there are eight possible outcomes with difference weights assigned to each branch in the tree based on considerations developed by the firm. The various factors in each scenario has been incorporated in the model for each scenario and the cost advantage of the coal boiler compared to gas estimated. Note that many of these are negative indicating that scenario shows natural gas to be least cost. The probability of each scenario is represented by the cumulative weights assigned to each of its branches which are depicted in parentheses. These cumulative probabilities annualized coal cost benefit. These are then summed to yield the most probable payoff of the coal choice. As is shown, the most probable benefit is -$.34 million annualized dollars, indicating that under these conditions, natural gas is the most prudent choice.

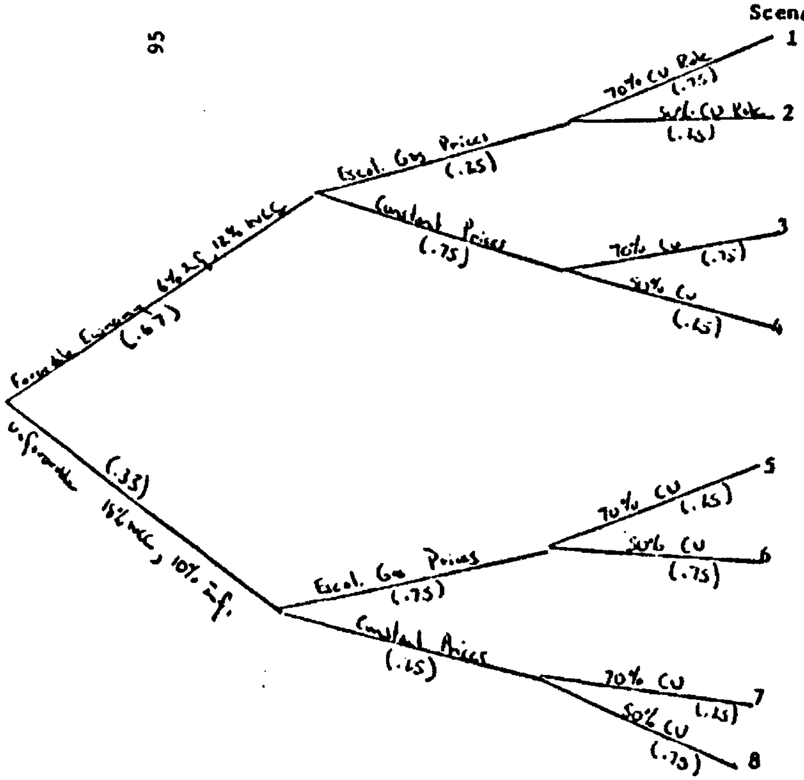
This illustration is quite important since it aids in explaining the lack of coal boilers noted in the NGP market. Short time horizons and future uncertainties in the economy make such ventures risky.

Other Considerations

Other factors that might influence the decision include economic growth rates in industry, world oil price and the environmental regula-

Figure 5.5
BOILER FUEL CHOICE UNCERTAINTY ANALYSIS

Scenarios



Coal Savings	Scenario Weights	Expected Payoff
$1980 * 10^6		$1980 * 10^6
(1) .51	.1256	.0641
(2) .26	.0419	.0109
(3) -.26	.3769	-.0980
(4) -.77	.1256	-.0967
(5) .05	.0619	.0031
(6) -.71	.1856	-.1318
(7) -.68	.0206	-.0140
(8) -1.20	.0619	-.0743
	Total	$ -.34

tory climate. Generally, higher world oil prices tend to slow economic growth. Such a slowing economy reduces capacity utilization rates and increases equipment life. Often this results in a more cautious assessment of new investment decisions. Many firms may postpone a decision until the prospects become more clear, extending the use of current equipment beyond its prescribed life.

High lending rates or prospects of them, tends to produce corporate fiscal policies that minimize capital expenditures and shorten the allowed period for its return. There is also evidence that coal fired units may have an additional "risk" premium assigned to the fixed charge rate because of less experience with coal, particularly with pollution control equipment. This may also lead to a desire to increase the rate of required return on investment and stipulation of more expensive total equity financing (Multari, 1981).

Finally, non-market factors such as the high regional cost of construction labor and the lack of skilled labor for plant operation may be discouraging to speculators (Glass, 1981). The high transportation costs for produced goods to distant markets may provide incentive for industry to locate coal more proximate to markets. This could include choice of Illinois coal for Ohio valley industry and Utah coal for the California market.

Conclusions

The fuel choice decision for industrial boilers is not currently clear in the Northern Great Plains region. Although the reference case analysis shows coal to be marginally least cost, numerous variables can easily swing this advantage to natural gas. Important among these are the large variances in the direct cost estimates of coal boilers (Table 5.7). Moreover, when the probabilities of uncertain future events are taken into account, natural gas appears to be the better choice.

Macroeconomic uncertainty exists with respect to future fuel price, capital costs and inflation rates. Higher petroleum fuel prices and higher inflation rates are beneficial to coal's choice. The larger the facility firing rate and the utilization rate, the more coal is indicated. This is particularly the case with distance ot the coal source, minemouth plants being the most competitive. Introduction of coal use by industry may be delayed by slow rates of economic growth and anticipation of future environmental regulations.

Expected firm strategies will be to extend the use of current equipment and to defer the investment decision as long as possible. If a decision must be made on replacement the least cost, risk minimizing strategy would be to choose a prepackaged natural gas system and to reduce utilization rates to minimize fuel costs. Capital expenses would then be reduced to the smallest possible expenditure and the shorter life of the equipment would allow a mid stream conversion to coal if it became indicated.

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CHAPTER SIX

INDUSTRIAL PROCESS HEAT FUEL CHOICE

Introduction

It is important to investigate the various types of industrial processes that could feasibly utilize coal as the primary plant fuel. The industrial sector is the largest energy consumer of all sectors in the U.S. economy at 37% (D.O.E., 1980). Energy use in this area can be characterized by functional end use in three broad categories. These are boilers, use as raw material feedstock and process heat applications. In terms of national industrial energy use, boilers represented 27% in 1974 while use in process heat applications and as a feedstock represented 22% each of the 25.3 quads of energy used (D.O.E., 1980). Chapter 5 analyzed the relative competitiveness of NGP coal as an industrial boiler fuel in comparison with other competing fuels. The use of energy resources for raw materials by the chemicals or steel industries represent uses that are relatively fixed in terms of the substitution of alternative fuels. Since the feedstock fuel often is a portion of the manufactured product itself (such as asphalt), it is doubtful if such raw materials can be easily substituted without compromise in final product.

Until recently, the industrial "process heat" category received little attention with respect to potential for coal substitution for oil or gas. Because coal use in boilers is a proven technology, initial studies have focused on the relative economics of this fuel choice and how legislative incentives might affect such use. Although process heat use in industry accounts for almost a quarter of total industrial energy use, technical feasibility of coal use in this area is only proven and demonstrated in cement and lime kilns. Although lead times and economics play a large role in limiting the extent of coal use in the process heat sector, it is technological feasibility that hampers coal use in these applications.

In a survey of industrial coal users within the NGP utility coal market area of 49 coal users, 29 of these, or 59%, can be classified in the process heat category. All these were in trona, bentonite, and cement manufacture. Use of coal in rotary kilns is the most proven of the process heat technologies.

This Chapter surveys technical constraints on process heat conversion from oil and gas to coal use. The economics of the process heat fuel choice are also examined in industries where coal use is feasible. The study will focus on seven energy-intensive industrial process heat users that rely primarily on natural gas. They are:

1. Foods
2. Textiles
3. Stone and clay
4. Glass
5. Cement
6. Petroleum refining
7. Primary metals

Particular attention will be given to the economics of fuel choice involved in cement, trona and bentonite manufacture, since these industries seem especially susceptible to coal conversion.

The economic analysis models the fuel specific cost factors that will weight future firm decisions in the market area. Variables consist of fuel heat and price characteristics, capital costs and operation and maintenance expenses as modified by pollution control costs. These expenses will be summarized in terms of annualized costs for comparison.

Technical Feasibility

There are three indigenous characteristics of coal combustion that limit technical feasibility for coal use in process heat applications. They are:

- Coal flame properties
- Heat distribution
- Product contamination and fuel characteristics

Burner size is a problem for some applications because of the coal flame characteristics which tend to be long, very radiant and slow burning. Reduction of flame length is possible, although not to the extent possible with a gas-like flame. Consequently, coal is excluded from some process uses because a well-controlled flame pattern is required, which cannot tolerate local overheating. Also, some existing cement kilns must have a minimum flame temperature which cannot be met by low Btu-NGP coal.

Heat distribution can be a problem because of the heterogenous chemical nature of coal itself and because of the coal particle sizes when it is crushed and pulverized. Coal Btu content may vary, causing further changes in resulting burner heat distribution. Although systems are being developed that will deliver coal to small burners with greater precision, the initial cost of such equipment is high in comparison to natural gas systems (EEA, 1980).

Coal combustion contaminants may impair end product quality, increase maintenance due to slagging on furnace surfaces, plug furnace aperatures, or decrease furnace life. Furnace wear is caused by corrosion from chemical products of coal burning by erosion and fluxing. This may adversely affect furnace operating life and O&M costs. The contaminants may also combine chemically with the heated product and deteriorate its quality. This is often the case for uses in the glass industry. The contaminants are most commonly sulfur, vanadium, and ash.

Ash products are particularly important in this respect. The ash can ruin products by simple contact or by chemical reactions that may compromise their qualities. In conjunction with sulfur ash tends to attack furnace metal surfaces through corrosion and slagging. Corrosion is usually due to fluxing where chemical reactions on the metal surfaces may reduce the surface melting points and result in deterioriation.

Slagging is a significant problem with Northern Great Plains coal. If furnace temperatures exceed the ash fusion temperature of the coal, then these products melt and deposit themsleves on furnace walls and refractories. This reduces furnace efficiency with accumulation. Periodically the furnace must be shut down to remove the products. It is common for process heat users to specify required ash fusion temperature floors; coals falling below these levels (2200° - 2500F) are not acceptable for plant operation.

The Powder River basin coals tend to have low ash fusion temperatures on the order of 2000 - 2300°. In order to utilize this coal either furnace operation must remain below this temperature level or increased O&M costs for furnace cleaning must be accepted.

Problems of excessive furnace aperature plugging are difficult if molten ash is involved. However, proper equipment design and sootblower can usually solve these problems.

Potential for Subsitution

The decision as to whether solid coal can be used for direct process heat in industry is parimarily an engineering judgment. During the decline in coal use in industry following World War II, little research was pursued as to technologies suitable for coal use. Most efforts were directed toward converting to the plentiful clean and cheap resource of natural gas. However, after the OPEC oil embargo of 1973, a representative group of industrial engineers were called together to assist in the design of the plan for industry in President Nixon's Project Independence. They were asked to evaluate the potential for substituting coal for oil. While citing a significant potential for using coal in boilers, they were pessimistic about the prospects for using the fuel for process heat. "The obstinant environmental, logistic, lead time, and economic demands associated with coal as a solid fuel are a strong inducement for a commitment, instead to a liquid or gaseous derivitive." Thus, the panel recommended a national move to synthetic fuels production to use coal more widely in industry.

In 1977 the Institute of Gas Technology analyzed the potential for solid coal use in industrial non-boiler applications. They selected a large number of industrial processes but only identified two sectors that seemed promising for immediate conversion -the stone, clay and glass, and primary metals categories. The particular processes cited were cement and lime calcining, glass melting, iron ore beneficiation, blast furnace and open hearth operations, soaking pits, copper smelting, and structural clay products. The study concluded that complete conversion of existing burners will save about one quad Btu per year in avoided petroleum use.

A more thorough study was completed in 1978 by Energy and Environmental Analysis for the Congressional Budget Office. The report classifies non-boiler coal feasibility in terms of the risk of failure associated with the appropriate coal technology. The four risk categories are:

1. Proven: coal is currently used in the process in the U.S.
2. Low risk: no insurmountable technical obstacles, but coal-burning equipmment must be built and proven before commercially available.
3. High risk: development of coal-burning equipment may be possible, but the technology is not demonstrated and system reliability is questionable.
4. Infeasible: without breakthroughs in combustion technology, coal cannot be utilized.

Table 6.1 examines EEA's findings in terms of seven industrial non-boiler uses:

Table 6.1
Technical Feasibility of Coal Use in Non-Boiler Applications

Industry	1974 Petroleum Consump. (Quads)	Proven	Low Risk	Coal Feasibility % of Total High Risk	Infeasible
Petroleum Refining[a]	1.81	-	50	29	9
Steel[b]	.64	18	25	6	-
Aluminium[c]	.17	-	33	-	47
Stone, Clay, Glass[d]	.80	58	-	33	-
Ammonia[e]	.59	-	100	-	-
Ethylene[f]	.99	-	-	-	100
Other	2.92	-	-	-	-

Source: EEA, Inc. 1978. Technical Potential for Coal Use in Industrial Equipment Other than Boiler. Washington D.C.: Congressional Budget Office.

[a]Low risk: atmospheric distillation, catalytic reforming, aklylation; high risk hydrocracking, hydrotreating, vacuum distillation, hydro refining, hydrogen manufacture.
[b]Proven: coal oil mixture, open hearth process, low risk reheat furnace.
[c]Low risk: melting, holding, and casting; infeasible, calcination and fabrication.
[d]Proven: cement, lime and brick production, high risk, glass manufacture.
[e]Low risk: in use overseas.
[f]Infeasible: precise temperature control required.

SECTOR SPECIFIC FEASIBILITY

Seven manufacturing groups consumed 69% of the energy in the manufacturing sector in 1974. Each group relied primarily on natural gas as its energy source. Coal used was confined predominantly to boilers. The following analysis evaluates the prospects for direct process heat use of coal in each sector in terms of technical feasibility.

FOOD INDUSTRY

The food industry has diverse heating requirements, but most involve direct heat and use natural gas as their fuel source. Product contamination concerns eliminate coal and any other heavy hydrocarbon fuels as possible alternative fuels. Increases in prices of natural gas and distillate oil may increase the sector's demand for indirect boiler heat.

TEXTILE INDUSTRY

Direct heat in the textiles industry is primarily used for singeing, drying and dye heat setting. Such uses require a clean and highly controlled heat in order to assure product quality. Soot contamination precludes coal or textile use. Natural gas is expected to be the primary fuel for sometime.

STONE, CLAY AND GLASS

The stone, clay and glass (SCG) industries include cement, lime, clay, brick, and glass manufacture. Combustors in this sector vary widely according to their ability to use coal. Natural gas is the primary fuel in the industry except in cement and lime production. Direct coal use is infeasible in some applications such as glass annealing because of product contamination. Most SCG manufacture can feasibly use coal, although some (for example, glass manufacture) fall under the rubric of low to high technical risk.

This category is particularly important to analysis of NGP process heat fuel choice because it represents the greatest use of coal in the NGP utility market areas. Survey research has discovered seven bentonite drying industries using NGP coal, five using Green River, Wyoming, coals for trona preparation, 12 Portland cement plants using coal, and one lime manufacturer.

It also represents the industrial sector most able to convert from petroleum to coal consumption. Fuel contamination does not detract from product quality and forms a necessary portion of raw feedstock for the production of cement and lime. The cement itself absorbs SO_2 obviating the need for expensive FGD equipment (Gyftopoulos, 1979). EEA estimates that 87% of SCG units presently using petroleum fuels could be constructed to burn coal and 83% could be retrofitted (EEA, 1980).

The SCG industries, particularly cement manufacture, tend to be extremely energy-intensive in terms of final product and relatively labor-detensive. Assuming utility maximation on behalf of manufacturers, industries with high energy - labor ratios would benefit by adopting procedures to reduce energy consumption and/or the expense of energy consumption (Hannon and Herendeen, 1975). Cement manufacture is even more energy-intensive than chemical or aluminum production with a relatively uncompressible labor force. Industries with energy intensities greater than $.14 \times 10^6$ Btu/\$1963 final demand and low employment to dollar ratios will seek to minimize energy costs in a competitive market. All of the SCG industries fall under this heading. In 1974 cement and lime kilns accounted for nearly half of process heat energy at 2.58×10^{14} Btus (E.I.A., 1980).

PETROLEUM AND CHEMICALS

The process heat uses in petroleum and chemical synthesis are extremely energy-intensive. Together the two industries used 44% of the natural gas and 38% of fuel oil used in direct heat applications in 1974 (EEA, 1980). These industries use the most energy per dollar of added value of product of any industry (49 - 73 Kcal x 10^3/\$1971 dollar value added). Furthermore, whereas many industries have shown a declining energy input per constant dollar of product, energy use in the petroleum industry has actually increased 34% from 1959 to 1971 (Cook, 1976).

The potential for coal utilization varies widely by application, depending on required temperatures, reactivity and coking potential of the feedstock and heat distribution characteristics. Generally units operating at less than 800F^o have less demand for coking and require a highly controlled heat that would prevent use of coal. Tubestill heaters used for atmospheric distillation and alkylation are examples of such applications. Retrofit of such facilities seems unlikely, given the very large capital costs and slow retirement of this industrial group. EEA estimates that 79% of new petroleum refining operations could feasibly use coal, although 29% of these operations would fall under a high risk heading (EEA, 1980). These higher risk processes include hydrocracking, hydrotreating, vacuum distillation, hydro refining and hydrogen manufacture. Industry officials claim that capital costs for low-risk catalytic refining equipment is so large that the reliability of coal would have to be well demonstrated before being considered for new units. Furthermore, much of the direct heat is produced from internally produced refinery "off gas," by products of the refining process itself. It would be difficult to force refiners to ship in coal and sell this gas elsewhere (Congressional Budget Office, 1978). Although many of the processes in the industry can possibly use coal, the poor economics of these options makes this unlikely.

Prospects for coal use for direct heat in the chemicals industry is low. EEA estimates that only 2% of new chemical plants could use coal for direct heat and only half of these can feasibly retrofit. Currently large quantities of natural gas are consumed in ethelyene production, which is used to manufacture a wide variety of synthetics. However, coal use is infeasible because of necessary heat distribution requirements. The most promising use of direct coal heat is in the production of ammonia - a key ingredient in fertilizer production. The process is now in use in Europe and Asia, where coal is used as a feedstock and also as a process heat source. A plant has been proposed at Circle, Montana by Dryer Bros., Inc., that would use Northern Great Plains coal in such an application. Currently (Summer, 1983) there are no plans to build this facility. The Exxon facility in Billings is the only major petroleum refinery in the market area.

PRIMARY METALS

The primary metals industry relies on natural gas for about two-thirds of its process heat requirements. Coal use is considered feasible in 44% of new or retrofit steel applications and about 33% of aluminium industry requirements.

In steel furnaces, natural gas is often used to fire the moving beds of sinter and iron ore products on traveling grates. Since the products of this process enter the blast furnace, there are few constraints due to contamination from coal use, although such conversions may not be economic. Coal use for direct heat is considered feasible for all but coke ovens and blast furnace stoves. Many of these conversions would require expensive FGD pollution control or particulate control equipment. Also, most existing facilities exist in non-attainment areas.

The use of coal for aluminium production is more constrained and of greater risk. Although aluminium rotary kilns are essentially the same as cement or lime kilns, fuel containing any significant level of contaminants cannot be used. Only in aluminium lime calciners, anode prebake ovens, and reverberatory furnaces is coal use a feasible option. Natural gas is currently used for all these applications. It burns cleanly and has a low capital cost.

Feasibility Summary

Of the non-boiler processes studied, involving 54% of non-boiler use of oil and natural gas, only 7% could be considered to have proven technologies, although 20% were found to have a low risk potential. The other half were judged high risk or infeasible and are probably not accessible to coal conversion in the period studied (1985-2010). Even with the low risk potential, market penetration appears contingent on successful commercial-scale demonstration of the coal technologies. The possible candidates for new plant construction or retrofit appear to be in the steel, sand, clay and glass, ammonia industries, and to a lesser extent with aluminium manufature. Steel industries are concentrated in the northeast and are not found in the market area.

Technical feasibility of industrial process heat use in the market area appears to be concentrated with the cement, lime, trona, and bentonite manufacture in the SCG category. Ammonia production from coal is feasible.

LEAD TIME FACTORS

For all process heat installations there are lead time factors that affect the date of commercial availability. For proven coal combustion technologies this limitation is primarily one of market penetration of coal use, design, engineering, and construction times. Even for proven technologies, Energy and Environmental Analysis estimated that only about half of new units would install coal (EEA, 1980). From date of commitment this will often take two years or more.

For unproven or higher risk technologies much longer lead times are to be expected. Demonstration plants must prove themselves before commercial market penetration will occur. It would probably take three to four years to build and prove a new technology before other commercial facilities would be willing to purchase it. Another two years would be required to build the first commercial plants. Optimistically the first commercial plants would come into use five years after the start of the demonstration project. Even then, the percent of the market penetration of the new technology would initially be a maximum of about 10% per year, assuming it is economic, (EEA, 1980).

The basis of the slow pace of non-boiler market penetration is the uncertainty associated with use of the new technology both in construction and operation. Industry is not only cost minimizing but also risk averting. Often, competing industries will watch a new technology for a period of time in order to assess its potential reward in terms of future risks. The risk averting nature of the private sector does not immediately lend itself to such ventures without substantial financial incentives. Other important variables in market penetration are expected product demand growth and rate of old capital retirement. Given an existing demonstration plant or a proven technology with one year of proven performance, a market penetration rate of 20% in two years, 50% in five years, and 75% in 10 years has been established based on an industrial history of economically advantageous technology introduction (EEA, 1980).

Modeling Process Heaters

It is not possible to model a single representative process heater as was estimated for the boiler population in Chapter 5. Instead information must be developed for a number of plant configurations to cover the spectrum of potential applications. After developing capital cost, fuel use characterictics and operation and maintenance cost schedules, it is possible to calculate an annualized cost comparison between natural gas and NGP coal.

The processes chosen for modeling were those existing or considered possible in the market area. Thus, potential process heat uses for the petroleum refining and steel industries were omitted. Table

6.2 summarizes combustor characteristics in terms of type, firing rate, capacity utilization, useful life, and necessary pollution control measures.

Table 6.2
Modeled Process Heat Plant Characteristics

Industry	Type	Firing Rate (10^6 Btu/h)	C.U. (%)	Life (yrs)	Pollution Control for Coal or Residual Oil
Glass	Regen. glass melter	50	.90	5	FGD
Cement	Rotary kiln	333	.90	30	None
Lime	Rotary kiln	96	.90	30	None
Aluminium	Lime calsiner	96	.90	30	ESP
Aluminium	Anode prebake oven	20	.90	30	ESP
Aluminium	Reverbratory furnace	40	.90	20	ESP

* FGD, flue gas desulfurization; ESP, electrostatic precipitator. From EEA. 1980. Industrial Fuel Choice Analysis Model, Arlington, Va., G-2; DOE, "Technical and Economic Feasibility of Alternative Fuel Use in Process Heaters and Small Boilers", EIA-10547-01, Washington, D.C. D-6.

Coal use in regenerative glass melting was modeled. Aluminium plants exist in the market area, and coal use is of low risk in the three processes shown. Also, the fuel choice decision for cement and lime kilns is depicted.

FUEL CHARACTERISTICS

Appropriate fuel characteristics for the model are taken from Table 4.4 in regard to heat content and emissions parameters.

Table 6.3
Fuel Characteristics

Fuel	Sulfur (%)	Ash (%)	Btu Content	TSP Emission Rate	TSP (10^6Btu)	Lbs SO_2/ 10^6Btu
NGP Coal	0.5	9.0	8,600/lb	13.16/ton	6.88	1.18
Resid. Oil	3.0	0.0	150,560/gal[a]	8.016/10^3gal	.05	3.14
Distil. Oil	0.3	0.0	146,430/gal[b]	8.016/10^3gal	.06	.31
Bat. Gas	0.0	0.0	1,027/ft^3	10lb/10^6 ft^3	.01	.0001

From EPA, 1975. Compilation of Air Pollution Emission Factors, Pub AP-42, Research Triangle Park, N.C. p. 1.4-2.

[a] Gallon = 7.882 lbs.
[b] Gallon = 7.571 lbs.

POLLUTION CONTROL ASSUMPTIONS

Applicable pollution control measures for process heaters is difficult to determine, since coal has been used in few of such combustors. Few pollution control regulations exist with regard to process heat uses. Coal use in proven applications such as cement kilns does not pose significant air pollution problems because SO_2 and ash pollutants are directly incorporated into the product. Since uncontrolled emissions rates for such combustors are largely unknown, particulate removal is required for all small units and FGD equipment on those with firing rates of 50 x 10^6Btu/h or greater or for units where applicable regulations currently mandate FGD equipment. The revised new performance standards, prevention of significant deterioration and nonattainment provisions described in Chapter 5 are assumed in this analysis. The aluminium lime calciner depicted will remove SO_2 given the chemical process involved, but not particulate matter; therefore an electrostatic precipitator was required in this case. A double alkali FGD system is assumed, as is an electrostatic precipitator in other cases requiring pollution control. Equipment costs were taken directly from information used to calculate their expense for the boiler analysis.

Economic Methodology

The economic modeling methodology for process heat combustors is a duplication of the previous procedure for boilers. Direct, indirect, and total capital costs are estimated for the various units modeled, along with operation and maintenance and fuel costs. These charges are then annualized according to the expected life of the facility and applicable financial parameters. This procedure is carried out for each of the four fuels to compare their respective annualized costs. These costs are then used to predict individual firm decisions as to which fuel will be chosen.

CAPITAL COSTS

Direct capital costs for the various process heat configurations modeled were obtained by inflating the 1978 equipment price quotes developed by Energy and Environmental Analysis for D.O.E.'s "Industrial Fuel Choice Analysis Model" according to the producer price index for "industrial heating equipment." In some cases where information was unavailable, especially in regard to pollution control equipment, cost data was taken from the boiler model. The estimation procedure is a duplicate of that study and is not repeated here. Direct, indirect, and total capital costs are listed for the various processes in the following tables.

Table 6.4
Direct Capital Costs for Industrial Process Heaters ($1980 10^6)

Type	NGP Coal	Dist. Oil	Res. Oil	Nat. Gas
Regen. Glass Melter	3.22	2.37	2.71	2.23
Rotary Cement Kiln	13.08	11.66	12.14	10.70
Rotary Lime Kiln	4.21	3.66	3.86	3.39
Al. Lime Calciner	4.33	3.66	3.86	3.39
Al. Anode Prebake	10.17	9.94	9.92	9.82
Al. Revergratory Furnace	2.62	2.25	2.26	2.14

From E.E.A., 1980, Industrial Fuel Choice Analysis Model, Arlington, Va. P.6-19.

Table 6.5
Pollution Control Capital Costs for Industrial Process Heaters ($1980 10^6)

Type	NGP Coal	Dist.* Oil	Res. Oil	Nat. Gas
Regen. Glass Melter	.66	.08	.66	0
Rotary Cement Kiln	0	0	0	0
Rotary Lime Kiln	0	0	0	0
Al. Lime Calciner	.30	.15	.25	0
Al. Anode Prebake	.07	.03	.05	0
Al. Revergratory Furnace	.14	.06	.10	0

* ESP or baghouse required.

From ICF, Inc., 1979, Economic Considerations in Industrial Boiler Fuel Choice, Washington, D.C. pp. II-54, II-56.

Table 6.6
Total Capital Costs for Industrial Process Heaters ($1980 10^6)*

Type	NGP Coal	Dist. Oil	Res. Oil	Nat. Gas
Regen. Glass Melter	5.43	3.43	4.72	3.12
Rotary Cement Kiln	18.31	16.32	17.00	14.98
Rotary Lime Kiln	5.89	5.12	5.40	4.75
Al. Lime Calciner	6.48	5.33	5.61	4.75
Al. Anode Prebake	14.34	13.96	13.96	13.75
Al. Revergratory Furnace	3.86	3.23	3.30	3.00

*Includes direct costs of heaters, pollution control, and indirect costs.

OPERATION AND MAINTENANCE COSTS

In keeping with the fuel-specific comparative approach, this section develops operation and maintenance costs. These costs are assumed to escalate at 1.0% annually in real terms.

Table 6.7
Annual O&M Costs for Industrial Process Heaters ($1980 10^6)*

Type	NGP Coal	Dist. Oil	Res. Oil	Nat. Gas
Regen. Glass Melter	.85	.15	.17	.13
Rotary Cement Kiln	1.27	.83	.93	.71
Rotary Lime Kiln	.42	.27	.31	.23
Al. Lime Calciner	.57	.27	.46	.23
Al. Anode Prebake	.44	.21	.35	.18
Al. Revergratory Furnace	.29	.14	.23	.12

* Includes pollution control costs.
From D.O.E., 1980, Technical and Economic Feasibility of Alternative Fuel Use in Process Heaters and Small Boilers, DOE/EIA-10547-01, p. 1, D-6, EEA, 1980, IFCAM, Arlington, Va., G-19.

FUEL COSTS

Fuel costs were developed in a detailed fashion in Chapter 5. The relevant procedure for price estimation is similar here, and can be drawn from that section without change. Modified, uniform present worth analysis was used to project industrial fuel prices over time and to discount future fuel cost streams.

Table 6.8
Montana Industrial Fuel Prices \$1980/10^6 Btu

Fuel	1980
Coal	.64
Res. Oil	3.43
Dist. Oil	6.10
Gas*	2.62

* Assumes no PIFUA.
Source: EIA, 1983. Energy Expenditures and Price Data Report, DOE/EIA-0376.

Computation of annual fuel costs for the various plants is straightforward. All modeled plants have capacity utilization rates of 90%. They operate 7,884 hours per year, which is then multiplied by their hourly firing rate to arrive at an annual fuel consumption in million Btus. This is then multiplied by the cost per million Btus of the fuel and is estimated in Table 6.9.

Table 6.9
Initial Year (1980) Fuel Costs for Industrial Process Heaters
($1980 10^6)

Type	10^6Btu/yr	NGP Coal	Res. Oil	Dist. Oil	N-Gas
Regen. Glass Melter	394,200	.25	1.35	2.40	1.03
Rotary Cement Kiln	2,625,372	1.68	9.01	16.01	6.88
Rotary Lime Kiln	756,864	.48	2.60	4.62	1.98
Al. Lime Calciner	756,864	.48	2.60	4.62	1.98
Al. Anode Prebake	157,860	.10	.54	.56	.41
Al. Revergratory Furnace	315,360	.20	1.08	1.92	.83

Fuel escalation rates are based on growth from Table 5.18 of Chapter 5 for the medium world oil price. The assumed annual real price escalation rates are as follows:

Coal:	1.0%
Residual Oil:	2.0%
Distillate Oil:	2.0%
Natural Gas:	4.0% first ten year, 2% thereafter

The fuel cost streams are thus discounted over the life of the plant, whereas fuel costs are escalated at the above rates.

$$UPW = A \frac{(1+e)}{(i-e)} \quad 1 - \frac{(1+e)^n}{(1+i)}$$

where A = cost in year (1), 1985

e = escalation rate of fuel price (%)

i = discount rate (10%)

n = plant life expectancy

The above formula translates the fuel cost stream into a present value sum. In accordance with the annualized cost procedure being developed, this must then be spread out over the life of the investment. This is accomplished by using a capital recovery formula for the appropriate real cost of capital of 9.09% and the applicable time period:

$$A = P \frac{(i\ (1+i)n}{(1+i)^n - 1)}$$

For a discount rate of 10% the capital recovery factor is .10608 for a 30 year investment, .11746 for 20 years, and .26380 for 5 years.

The levelized plant fuel cost is then determined:

R = UPW* x CRF

R = annualized fuel cost

UPW* = discounted fuel cost present value modified by real price escalation rate

CRF = capital recovery factor

Annualized Costs

The method used for comparing firm decisions is exactly as that used in Chapter 5. The present value of the investments over the plant lifetime are evaluated. This is accomplished by representing the present value of the cost stream as a series of real annuities. Thus the annuities are readily comparable in terms of the relevant fuel choices. These annualized costs consist of the sum of the annual fuel, O&M and capital costs. The assumptions used are identical to those used in Chapter 5. Table 6.10 sums the plant specific annuities in terms capital charges, O&M and fuel for the levelized cost on which fuel choice will be determined.

Table 6.10
Total Annualized Costs for Industrial Process Heaters ($1980 10^6)

Type		Fuel NGP Coal	Res. Oil	Dist. Oil	N-Gas
Regen. Glass	Capital	1.03	.89	.65	.59
Melter	O&M	1.71	.34	.30	.26
	Fuel	1.06	3.23	5.75	2.78
	Total	3.80	4.46	6.70	3.63
Rotary	Capital	1.66	1.55	1.48	1.36
Cement	O&M	1.43	1.05	1.05	.80
Kiln	Fuel	4.03	12.95	23.03	10.37
	Total	7.12	14.55	25.56	12.53
Rotary	Capital	.54	.49	.47	.43
Lime	O&M	.47	.35	.30	.26
Kiln	Fuel	1.16	3.73	6.64	2.99
	Total	2.17	4.57	7.41	3.68
Aluminium	Capital	.59	.51	.48	.43
Lime	O&M	.64	.52	.30	.26
Calciner	Fuel	1.16	3.73	6.64	2.99
	Total	2.39	4.76	7.42	3.68
Aluminium	Capital	1.30	1.27	1.27	1.25
Anode	O&M	.50	.39	.24	.20
Prebake	Fuel	.24	.78	1.38	.62
Oven	Total	2.04	2.44	2.89	2.07
Aluminium	Capital	.38	.33	.32	.30
Reverbratory	O&M	.32	.25	.15	.13
Furnace	Fuel	.46	1.46	2.59	1.18
	Total	1.16	2.04	3.60	1.61

Oil is not competitive with coal or natural gas for use in process heat installations. The strongest economies in favor of coal are evident in cement, lime kilns and aluminium lime calciners. Other applications, particularly the glass melting plant, show little economic advantage for coal use over natural gas. A formal uncertainty analysis is unnecessary since the annualized results are not very close. If this was done, it would undoubtedly show the only economic processes for coal use are cement and lime kilns and possibly aluminium lime calciners.

Conclusions

A primary deterrent to using coal in process heat applications is the technical feasibility of its use. Coal often requires expensive handling and pollution control equipment. Combustion is made difficult to regulate and requires more maintenance due to corrosion and fluxing. Most feasible uses in the NGP market area such as cement and bentonite kilns are already using coal an indication of its significant economic advantages. Most other industries susceptible to process heat coal conversion such as the steel industry are not located proximate to the market area. Because of the existence of the aluminum industry, such as that in Columbia Falls, the feasibility and economics of coal substitution in various processes related to aluminium production were examined. While the three uses - lime calcining, anode prebake ovens, and reverbratory furnaces, are technically capable of using coal, this substitution is not demonstrated. Lead time factors would tend to delay coal use penetration in this industry, at least until the 1990s. Even so, the economic advantage of coal is not so overwhelming in these applications as to result in a rush into coal use, particularly within an untried technology.

NGP coal use in process heat applications will most likely be tied to developments in the cement, lime and bentonite industries. In the survey of industrial coal users in the market area, all cement and lime kilns save for one were using higher Btu western coal from sources other than the Northern Great Plains. This is partially explained by the design characteristics of existing kilns that have definite heat and moisture content requirements for coals burned. Thus, the greatest prospect for NGP from process heaters will likely come through location of future cement plants close to the coal resource.

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CHAPTER SEVEN

SURVEY OF INDUSTRIAL COAL PRODUCTION AND USE

Introduction

In the summer and autumn of 1981, a survey was conducted in order to determine the extent of industrial coal production and utilization in the 21-state Northern Great Plains utility market area. The survey was designed to locate both industrial coal users and also the sources of supplied coal. Prior to this effort the only data source for this type of information had been through the monograph produced by the geological survey of Wyoming (Glass, 1980) and the compilation available from the Keystone Coal Manual (Mining Information Services, 1980). However, the Glass study only pertains to Wyoming production and both sources were found to be less than complete. Consequently, it was decided to query all producers of NGP coal and also all known industrial users of coal within the 21-state market area.

Method

Twenty-four producers and 48 consumers were contacted. In both surveys sensitive questions were posed and it was expected that not all queried would respond. However, in order to maximize the probability of response, two surveys were mailed. The first was sent to all producers and consumers in mid-August. The second was mailed six weeks subsequent to all who did not answer the first survey. NGP producers were asked whether they had any industrial contracts, the annual tonnage of these contracts, the name and location of the industries supplied and the FOB/ton price of these contracts.

Users were asked the source of their coal, the factors which influenced their decision to choose that coal and whether or not the facility was designed to burn coal or was retrofitted. They were also asked whether there would be technical constraints to the use of NGP coal in their facilities.

<u>Response</u>

The usefulness of the individual survey responses varied considerably both with respect to the return rate and the scope of the ventured information. Because of the sensitive price information asked by the survey, numerous producers did not answer and several declined to provide contract information. Others felt that all of the questions were too confidential to answer, although anonymity of such data was promised. In general, industrial coal users were more helpful in supplying information than were producers who cited the extremely competitive nature of their business in not releasing the answers. Table 7.1 and 7.2 summarize the success rate of the two surveys in eliciting information from either source.

Table 7.1
Industrial Coal User Survey

	Number	Percent
Total contacted	48	100%
Respondents	22	46%
Address Unknown	5	10%
No Response	21	44%
Decline to Answer	0	0%

Table 7.2
Industrial Coal Producer Survey

	Number	Percent
Total contacted	24	100%
Respondents	12	50%
Address Unknown	0	0%
No Response	8	33%
Decline to Answer	3	13%
Telephone Contact	4	17%
Overall Response Rate	16	67%

Classification

Of the 48 industries using coal discovered in the market area, 25 could be categorized as process heat uses with the other 23 use coal for firing boilers. The greatest industrial use of coal in the market area was for cement and lime kilns. Table 7.3 breaks down the industries surveyed by coal use.

Table 7.3
Coal Use Classification in Surveyed Industries

	Number of Plants	% of Total
Cement and Lime Kilns	14	29%
Trona Manufacture	4	8%
Bentonite Kilns	7	15%
Sugar (boilers)	10	21%
Paper (boilers)	4	8%
Other (boilers)	9	19%

Because not all surveys were answered and data was omitted from some returned, it is impossible to weigh these percentages by annual tonnage used. However, given the available responses to the survey, it is possible to approximate the required tonnage for the various plant operations listed above and the resulting total demand for that number of plants. This is depicted in Table 7.4.

Table 7.4
Industrial Coal Demand in the 21-State NGP Market Area 10^3 Short Tons/Year

Category	Range of Demand	# Plants	Demand	Total Demand
Cement & Lime Kilns	70-400	14	2,500	40%
Trona	100-600	4	1,500	25%
Sugar	30-180	10	1,020	17%
Paper	30-180	4	300	6%
Bentonite	5- 15	7	60	1%
Paper	5-300	9	610	10%
	5-600	48	6,030	100%

Tables 7.3 and 7.4 are noncomprehensive samples of data from the entire 21-state utility coal market area. Total industrial coal in the region is around 53 million tons per year, of which 21.4 million tons per year is coking coal (mostly Indiana) and 31.6 million tons per year industrial and retail. Based on our survey of industrial coal sales and use within the 21-state area, it is discovered that plants using NGP coal are confined to an eight-state market. Based on available data, these states include the producing states of Montana, North Dakota and Wyoming as well as South Dakota, Nebraska, Colorado, Minnesota, and Wisconsin. This suggests an influence of transportation costs on the size of the NGP industrial coal market area. States proximate to the deposits in northwestern Wyoming, southeastern Montana and western North Dakota lignites are more likely to purchase NGP coals. The states to the west and southwest tend to purchase Green

River, Wyoming, or central Utah or Colorado coals that have a higher BTU content. The total industrial use of NGP coal we were able to identify was 1.5 million tons per year. We expect that our NGP eight-state data is much more comprehensive than the small sample reported above for industrial use in the 21-state utility market area. The eight-state industrial use of NGP coal was distributed as noted in Table 7.5.

Table 7.5
Industrial Coal Demand in the Eight-State NGP Market Area

Category	Demand	# NGP Coal Plants	10^3 Tons/Year Total Demand	% of Total
Cement & Lime Kilns	300	1	300	20%
Sugar	40- 80	12	736	47%
Paper	60-180	2	240	16%
Bentonite	5- 15	7	61	4%
Other	20- 60	4	160	11%
		26	1,497	100%

Probably the best estimate for NGP industrial coal use is to compare utility consumption to total coal production by year, and to assume that the residual (aside from stockpiling) is industrial and retail coal. A review of FERC data for 1975 to 1980 indicates that about 95% of Powder River coal production is accounted for by utility consumption. This would suggest use on the order of four million tons per year in 1980. We have not been extremely successful in accounting for the use of this "residual." Accordingly, Table 7.5 is best regarded as a sample with greater significant on proportions than totals. It may be noted that the greater (about 10%) industrial share of coal in the 21-state market area is logical, given metallurgical use in the Midwest.

As Table 7.5 illustrates, the NGP industrial coal market is dominated by the tonnage used by the South Dakota cement plant and use for sugar manufacture. A great portion is used for the North Dakota, Red River Valley sugar beet refineries and the remainder for Great Western Sugar's Billings Plant. Use of NGP coal in rotary bentonite drying kilns is a relatively new use, although that has prospects for increasing in the next few years. Two paper plants in Wisconsin using Colstrip coal account for this category of use. The classification of "other" consists of 120,000 tons per year used for heating of two universities in Grand Forks and Fargo, North Dakota and 40,000 tons per year used by Ashland-Exxon in Texas for an experimental coal gasification plant. The sugar companies supplied represented the largest number of plants and also covered the largest geographic areas. Plants were located in Nebraska, Montana, North Dakota, Colorado and Minnesota.

The supplying producers to these non-utility uses numbered eight of which three were North Dakota lignite producers and two each were Wyoming and Montana Powder River Basin operations. Of the total tonnages consumed, 57% was subbituminous coals while 43% consisted of lignite coals.

Statistical Analysis

The survey data obtained has been used to obtain important information for the industrial coal study. This includes F.O.B. cost estimates for the coal itself, the distance dependent cost of transport, the average distance from mine to the combustors and the average tons used per year for each facility. As is frequent with surveyed data, the number of responses varies by the item of inquiry. For the user survey there was a total of 48 inquiries sent. Of these, only 26 were using NGP coal. Moreover, for many of the data elements, there was non response from many of these so that the results consist of fewer elements than would normally be desirable in a rigorous statistical sample. Because of these generally poor results it was decided that a 90% confidence level would be appropriate to the analysis. It is then possible to examine the precision of the estimates based on the sample variance and the allowance error (Cochran, 1977):

$$n = \frac{t^2 \, S^2}{(ry)^2}$$

Where:
n = required sample size
t^2 = Z score of the confidence level (90%=1.65)
S^2 = the variance of the aggregate data
r = risk of error (1 - Confidence Level=.10)
y = the mean of the aggregate data

Since the sample size is given, it is possible to iteratively estimate the confidence level that must be accepted for the sample. A 90% confidence level is used as an optimistic starting point. Since the number of actual industrial plants in the market area is an unknown, we will assume that N/n is insignificant.

Table 7.6
NGP Industrial F.O.B. Coal Cost

N = 10
Mean = \$10.90
Std Dev. = \$2.01
Variance = \$4.04
Confidence Level = 90%

The average cost of NGP industrial coal is about 23% greater than that of utility contracts (\$8.90/ton). The 90% confidence level indicates that the true mean is contained in a confidence interval that is the product of the level Z score (1.65) times the standard deviation (\$2.01). The 30% confidence interval is thus between \$7.58 and \$14.22. A regression attempt to find relationship between tonnage and contract cost yielded interesting results. The result was:

FOB Price/ton = \$12.40 - \$.0000137 (Annual Tonnage)

N = 10

The slope coefficient is negative as would be expected, however R^2 is only .710 indicating that other factors than size of contract has an effect on the contracted price. However, such a correlation does indicate a general trend.

Table 7.7
NGP Industrial Transportation Distance

N = 26
Mean = 233.1
Std Dev. = 186.2
Variance = 34,656.6
Confidence Level = 80%

Although the average distance is over 200 miles, the results seem to be skewed toward the lower values indicating a possible log-normal distribution. As seen, there is considerable variance in these values and coupled with the low confidence level of the estimate few conclusions can be drawn from this data.

Table 7.8
NGP Industrial Coal Transportation Cost Over Distance

N = 13
Mean = \$.0701/Mile
Std Dev. = \$.0149
Variance = \$.00022
Confidence Level = 90%
Linear Regression: TransCost (\$1981) = \$2.86 + \$.0461 (Distance)
R^2 = .990
N = 10

This is an important estimate to the analysis. Unfortunately the sample size is quite small although variances were also tolerable for a 90% confidence level.

Table 7.9
NGP Industrial Coal Contract Amounts (10^3 Tons)

N = 26
Mean = 56.78
Std Dev. = 73.24
Variance = 5,364.1
Confidence Level = 70%

The contract tonnages vary quite a bit as seen in the low confidence level yielded by the sample size and the tremendous variance. Again, the frequency distribution is positively skewed towards the smaller contracts.

The poor response rate and low number of samples available from the NGP industrial coal survey serves to compromise the accuracy of the estimates available. Fortunately for the analysis, the variance in two key parameters, that of coal costs and transportation costs were reasonable.

The survey bias effects of non-response are difficult to accurately estimate, since the unanswered inquiries are unavailable. However, based on a method outlined by Cochran (1977), it is possible to guage the significance of this effect by dividing the two stage survey into two strata. In this case these two strata are based on the results from the first mailing and the second mailing and phone follow up. Bias in non-response is often revealed in comparing the means of the two separate strata for a trend in one of the considered variables. If the variation in the two means is less than the risk of error in the analysis then it can be surmised that there is little or no bias in the non-respondents.

In this analysis the mean contract tonnage of the initial letter responses was 43,850 while the mean of the follow up letter and phone calls was exactly 70,000 tons bias towards non-response with greater tonnage contracts. Furthermore, this was considerably greater than the allowance for error with the variance in the means approaching 40%. This is bothersome with respect to the final estimates described here of the total NGP industrial coal contracts. The identified tonnage is about 1.5 million tons per year. Since the data gathering rate was only 54% (response rate plus data gathered elsewhere) we would expect based on the average tonnage per respondent that the actual NGP industrial tonnage was about 2.2 million tons per year. However, if it is assumed that the non-respondents had larger contracts averaging 70,000 tons per year each, then the total industrial tonnage would be just over 3 million tons per year. This is probably a conservative guess since there is also the strong likelihood that some contracts were missed in the initial search for contacts. The actual tonnage probably is between 2 and 5 million tons per year. This agrees well with the FERC estimate of a non-utility, "residual" NGP coal use of about 4 million tons in 1980.

Results

From Table 7.4, for the 21-state area, one would expect that cement manufacture held the highest prospect for large use of NGP coal. This is, in fact, not borne out when actual data is examined (Table 7.5). All but one of the cement manufacturers were relying on Green River, Wyoming coal, Utah coal or Colorado coal. These consumers were closely queried and for the most part responded in a helpful manner.

The Ideal Basic Cement Company, representing numerous plants in the area, agreed that lowest delivered cost per heat value was an important factor, but not necessarily the most important in terms of coal selection. A minimum BTU content of 7,800 BTU/lb. to maintain proper flame temperature is necessary so that changes in kiln temperatures can be adjusted rapidly. Ash content was an important factor in that delivered coal must have a consistent percentage because of the fact that ash goes directly into the product. Specifically, the greater the coal ash content, the greater the quantity of expensive quarried limestone that must be used in the process. Finally, moisture content is important in that it affects the physical consistency of the coal when it is pulverized prior to being fed into the kiln. Consequently, coals with moisture contents greater than 20% are not acceptable because of agglomerating characteristics. NGP coal BTU values are typically greater than 7,800 BTU/lb. with an average of 8,600 BTU. While many have consistent ash contents, the ash content tends to be several percent greater than other western coals. Moisture content typically is more than 23%. Consequently, Ideal Basic plants procure their coal from the higher heat content coals of Eastern Wyoming around Kemmer. This is also true of the coal used in both the Idaho and Oregon Portland Cement Companies. The two cement plants in Montana, the Ideal Basic, Trident Plant and Kaiser Cement Plant in Montana City procure their coal from Eastern Wyoming and Price, Utah because of the aforementioned technical constraints. Kaiser Cement noted that while most NGP coal would not be acceptable, possibly Red Lodge or Roundup, Montana coal might burn satisfactorily. The single cement plant in the market, the South Dakota Cement Plant in Rapid City, uses Wyodak coal trucked from Gillette, Wyoming with a heat content of only about 8,000 BTU/lb. and a moisture content of about 30%. To convert the plant from natural gas to NGP coal use in 1979 cost $2,500,000. This fact stands out from the survey - that the costs of converting existing equipment to use NGP coal along with the transportation costs of moving the coal to the distant plants comprise an important deterrent to NGP coal use. Only where plants exist very close to an NGP resource, as in the case of the South Dakota plant, would conversion to capability to burn this coal be economically advised. However, existence of this abundant, cheap resource might provide incentive for locating new plants proximate to NGP sources.

Requirements for plants using boilers such as paper and sugar mills tend to be based on the type of coal for which the boiler was constructed. Because of a lower coal ash fusion temperature (NGP = 2000° - 2250°F) slagging is a problem and a high moisture content aggravates handling problems and reduces flame controllability. The lower heat content often means that steam production will be reduced without significant equipment change. The lower sulfur content of NGP fuels is such that this does not pose any problem to substitution. Consequently, the plant design has a large effect on the useability of NGP coals. Red River Valley sugar plants in North Dakota use an estimated 500,000 tons per year of nearby lignite with 6,600 BTU/lb. heat content and high moisture. They were specifically designed to use this fuel while other sugar plants in Idaho choose eastern Wyoming coal based mainly on transportation costs and a superior heat value.

The bentonite industry is not technologically constrained in its use of NGP coal and because of the close location of the raw material for bentonite production to NGP coals, increased use is likely. Furthermore, NGP industrial producers contacted felt that the prospect for expansion of this industry was good due to the use of the product for plugging dry holes from increased drilling for oil and natural gas in the overthrust belt. Use of NGP coal for manufacture of trona appears doubtful since the raw material is located near the coals of the Green River, Wyoming region.

Many of the boilers that currently use coal in the market area were retrofitted from use of natural gas. Given the slow rate of retirement of such plants and high transport costs for industrial coal - their location becomes one of prime importance in determining which coal they will choose. All replying to the survey indicated that delivered cost of heat was the primary consideration in fuel choice. The low costs of NGP coals may provide strong incentive for location of new plants near mining areas.

Transportation costs of moving industrial coal dominates the fuel choice in the market area. Because of the approximately doubled rate for single car deliveries vs. unit trains for utilities, the market area for NGP industrial coal is significantly smaller than that of the utility market. Comprising eight states, much of the coal is transported by truck short distances to the point of use or else by single or multiple car rail rates. Because of the higher transport cost for industrial coal, it cannot be shipped as far to the point of price equalization as with utility coal. Technical constraints in cement plants regarding the low heat value of NGP coals and their moisture contents inhibit its use within the market. This may be obviated in the future at the point that the increased costs of retrofit are offset. The low mine mouth costs of NGP coal does provide motivation for the location of new cement plants proximate to these sources. Although small, the bentonite industry could double in its coal needs in the next several years. The future of NGP coal use at the proposed Circle, Montana ammonia plant remains uncertain. The same is true for the proposed fertilizer project in Daniels County, Montana.

The use of NGP coals for industrial boilers is proven and is only constrained by transportation costs to the point of use and the increased equipment costs of using low BTU fuel. Industry may seek multiple car rates with the railroads in order to reduce the transportation price burden. Sugar and paper mills may likewise be provided with incentive to locate near cheap NGP coal sources as with the case of the North Dakota sugar beet refineries. However, there are problems in attracting such industry into the area due to nonresource barriers such as wood availability, the high cost of labor, the lack in the area of a trained labor force and distance from markets (Glass, 1981).

Use of NGP coal for cement manufacture is only promising for plants located close enough to offer adequately lower transportation costs over the cost of plant modification. This may become true in the future for the two cement plants in Trident and Montana City, Montana.

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CHAPTER EIGHT

ADVANCED COAL COMBUSTION TECHNOLOGY

Introduction

In a series of studies in the late 1970s, the U.S. Department of Energy established the engineering feasibility of using coal in a variety of industrial combustors. Direct firing of coal was technically possible for almost any boiler system regardless of size. Other consultants to DOE found that pollution control costs applicable to most large boilers tended to negate the fuel life-cycle cost advantages of coal systems. Furthermore, due to technical constraints a great portion of industrial process heat combustors were incapable of substitution of coal for natural gas. This category accounted for roughly 25% of the industrial fuel requirement in 1974 (DOE, 1980). Whereas policy adjustments could be tailored to persuade industrial commitments to coal (PIFUA, 1978; PURPA, 1978; NGPA, 1978; ETA, 1978), the process heat category is not easily converted. It was therefore recommended that other technological options be investigated to enable more of the industrial complex to be switched to non-petroleum fuels. This investigation took two courses. The first objective was to identify and develop methods of burning coals such as with the atmospheric fluidized bed combustion technique (AFBC), that would overcome these technological feasibility constraints. The other course was to alter the form of the coal fuel into a gaseous or liquified derivatives. This survey will briefly describe the development of these two options and their current status. The technologies will be examined in light of their potential effect on industrial demand for NGP coal.

Atmospheric Fluidized Bed Combustion (AFBC)

This technology offers a method of increasing coal boiler furnace efficiency, reducing their size and potentially, their cost. It consists of burning coal and/or other fuels in a bed of non-combustible material which is maintained in a fluid-like state by the flow of forced air through the bed. The bed often will consist of pebble sized limestone particles which react with sulfur dioxide released from the burning coal and capture this pollutant within the bed. Firetubes are immersed in the bed through which water/steam is circulated. This transfers the released heat energy and is also used to regulate the bed temperatures. Coal is introduced to the bed by mechanical or pneumatic feeders. Ash and spent bed materials are continuously removed through downcomers in the bed. Fly ash and partially burned coal are usually recombusted in a "carbon burnup cell" to utilize unoxidized carbon. Final flue gases and particulate matter flow overhead to baghouses before entering the stack. The method offers the following advantages over direct pulverized coal combustion:

1) The volumetric heat release of the system is about three times that for a conventional combustor and the high heat transfer rates to the working fluid results in a substantial reduction of the size of the units-about one half of a conventional boiler configuration. This promises prepackaged shop manufactured units up to 200 x 10^6 BTU/hr boiler equivalent (DOE, 1980). Currently such units must be field erected and are more expensive.

2) Use of limestone as a bed material offers 90% sulfur dioxide removal without the use of additional FGD systems.

3) The high heat transfer coefficients result in a lower operating temperature (1500-1750 F°.) and consequently lower nitrogen oxides emissions.

4) A variety of fuels can be fired including all ranks of coal, wood, waste materials and petroleum products with little alteration of the equipment configuration.

5) The high heat transfer coefficients results in a greater thermal efficiency of the system. For a given heat exchange surface, more heat is delivered to the working fluid.

Disadvantages of the technology are:

1) Heat can only be delivered to a fluid transfer agent and consequently applications to process heat combustors are limited to uses such as in refinery operations (Exxon, 1978).

2) The rapid heat transfer may impair certain operations due to chemical change in the involved working fluids such as coke formation in heated heavy petroleum feedstocks.

3) Sulfur dioxide removal in test units at high degrees of removal such as the 90% level have not proved reliable.

4) The technology has thus far only been demonstrated on a test scale. Although small units are commercially available, lead times are apt to be long because most AFBC units are being manufactured for the first time.

5) Capital costs for such units will be high initially with significant economies of scale when compared to conventional boiler units.

6) O&M costs may also be high because of large limestone requirements for bed rejuvenation, particularly with high rates of sulfur dioxide removal.

DEVELOPMENTAL STATUS

Although there seems to be no major technological constraints to commercial AFBC units, the use of the pollution control capability has only been demonstrated on a small scale (DOE, 1980). Approximately one dozen manufacturers currently offer commercial AFBC units in the U.S. and abroad. The majority of these units are of small size (75×10^6 BTU/hr). A few companies are willing to offer units up to a size of 500×10^6 BTU/hr firing rate.

Several AFBC utility pilot plants exist. The Department of Energy operates a 30 MWe plant in Rivesville, West Virginia and a 6 MWe test facility in Morgantown. Georgetown University in Washington D.C. is operating a 125×10^6 BTU/hr industrial test unit. Other testing is being conducted by the Electric Power Research Institute, the Tennessee Valey Authority (250 MWe) and American Electric Power (170 MWe). Major AFBC research abroad is concentrated in England, Scotland and Sweden (DOE, 1980).

TECHNOLOGY COST

In an analysis performed by Energy and Environmental Analysis (EEA, 1979) AFBC boiler units were found to cost 2-20% more than a conventional direct fired unit when evaluated on an annualized basis. It is expected that these cost differences will come down over the next twenty years to the point that AFBC will enjoy a slight cost advantage over conventional boilers. The main diseconomy posed by AFBC is the high initial capital cost of the facility - about 50% greater than the modeled boilers.

Indirect Heat

Indirect heat involves separating a heat sink from the combustor by the use of a heat transfer agent. Applications that cannot operate with direct firing of coal because of contamination problems can then use coal. A working fluid such as steam picks up heat and transfers it from the combustor to the process application. The fluid is recycled after its heat has been released in a closed loop operation. Various working fluids can be used such as water, air, Dow-therm, molten salts and molten metals. The system allows precise control over heat distribution and temperature control.

The principle disadvantage of the method is its relative inefficiency compared to direct fired configurations, typically ten percent less. The need for the heat exchange equipment increases the system size and cost. The systems are also limited by the possible operating temperatures for the working fluid which can seldom be over 1000 F°. Molten salt systems are being developed that function in excess of this range although the working fluids are quite reactive and difficult to handle. Systems operating at temperatures of less than 700 F° are commercially available-usually in conjunction with a boiler system with water as a working fluid.

TECHNOLOGY COST

The cost of indirect coal fired systems is expected to be in excess of a conventional direct fired system because of the additional cost and maintenance of the heat transfer equipment and resulting decrease in overall system productivity. The Department of Energy expects that indirect heat systems will primarily be used for small scale applications (10×10^6 BTU/hr). More extensive utilization of the technology is dependent on future industrial natural gas prices for processes unyielding to direct combustion of coal. Such systems will find greatest applicability in the process heat category. The economics of this method compared with low or medium BTU synthetic gas from coal is uncertain.

Coal/Oil Mixture (COM)

Coal/Oil mixture consists of finely pulverized coal (200 mesh) blended with residual oil to form a homogenous slurry. The percent of coal by weight in the mixture is typically 20 to 50 percent. Like residual oil, COM must be heated to 150 F°. in order to be pumped, and to over 200 F°. before being routed to the burner. The heating value of the fuel is lower than that of residual oil due to the lower volumetric heat content of the contained coal. The combustion of COM shows characteristics of both parent fuels. COM requires a larger furnace volume for complete combustion than does oil or gas and may require derating of the facility from 1-10%. COM also has greater need of pollution control than residual oil because of the increase in ash and sulfur components.

Two additional problems impede the use of COM. The mixture will settle out if allowed to stand and must be agitated constantly. Handling problems or uneven combustion may result from insufficient mixing. Pumps must be replaced with units capable of processing abrasive fluids and plumbing configurations altered to reduce bends and low points that may cause erosion and/or sediment deposition.

COM technology is presently experimental. The Florida Power Corporation and General Motors have completed two demonstration projects in the U.S. Also, commercial use of COM is underway in Japanese steel manufacture (Nemoto, 1981). The major application of COM technology is for retrofit of boilers currently using residual oil or in steel blast furnaces. There are currently no commercial plans either using COM or producing the fuel in the U.S.

TECHNOLOGY COST

The main cost of COM facilities is the fuel preparation equipment. The equipment changes necessary to burn COM could cost about a million dollars for a 175 x 10^6 BTU/hr boiler unit. This would be effectively doubled if there was to be onsite COM preparation. The derating of the retrofitted facilities would result in a higher annualized cost for steam. Consequently, capital costs for a 175 x 10^6 BTU/hr boiler modeled in previous sections using COM would be increased by over 25% although annual fuel costs would be somewhat lower. When this is calculated it is found that overall levelized costs of burning high sulfur oil are reduced by about one million dollars per year. This is still not as low as the modeled direct fired coal plant with FGD.

However, this does seem to be a viable short term technology for reducing cost for facilities currently using residual oil. This would also provide a more rapid return on investment through reduced fuel costs as opposed to slow returns available on new coal configurations.

The fact that COM fuel preparation facilities do not exist is critical; because of this and the need for engineering technology development, market penetration probably will not be evident before 1990.

Synthetic Coal Fuels

It is difficult to substitute coal for natural gas in the industrial process heat category. In response to this constraint, private and government research and testing of the capability of deriving synthetic fuels from coal has been extensive.

German production of fuel oil from coal in World War II and the existence of the Fischer-Tropsch Sasol plant in South Africa has proven that synthetic fuel production is feasible. However, to pronounce such processes as currently economic is a matter of speculation. A voluminous collection of literature on many aspects of synfuel production is already in existence. Even so, little documentation exists to support price predictions of snythetic coal fuels as being competitive with conventional petroleum fuels (DOE, 1980). Several studies have attempted to predict the cost of delivered synthetic substitutes to natural gas and fuel oil (Cochran, 1976, DOE, 1980). As recently as 1970, experts believed that coal liquids would be economically competitive if the price of crude oil doubled. Since that time, crude oil prices have nominally increased fivefold and the price competitiveness of these substitutes remains to be established (DOE, 1980). Without adequate commercial experience with these facilities, it is difficult to anticipate actual performance both with regard to financial attractiveness and net energy output. Although demonstration projects exist and no insurmountable technical barriers are evident, the Department of Energy does not expect significant market penetration of synthetic gas plants before 1995 (DOE, 1980). One reason is the extremely capital intensive nature of the construction process currently estimated at over $2 billion for a commercial sized facility. A study of "new technology plants" in the chemical and petroleum industries have shown that the final real costs of these plants were 2-4 times that of the original engineering estimates after correcting for inflation (Merrow, Chapel & Worthing, 1979). Operation of the plants so as to be environmentally acceptable is an even more intractable problem. This is particularly difficult with respect to extensive water needs of these plants - 4-7 million gallons per day (Probstein & Gold, 1978). Extensive commercialization of such an industry cannot be reasonably expected before the turn of the century. In independent forecasts, DOE, DRI and Exxon predicted 5, 3 and 6 quad BTUS of synthetic fuel energy produced in the U.S. by the year 2000.

Synthetic fuels described fall into two large categories, processes producing low and medium BTU gases from coal and those producing liquids. Many are based on hydrogenation of coal usually in reaction with steam.

Low BTU gas (100-200 BTU/ft^3 vs. 1000 BTU/ft^3 for natural gas) is produced by injecting a hot bed of coal with air and steam. Medium BTU gas is produced similarly with pure oxygen substituted for air (200-500 BTU/ft^3). The efficiency of the processes in converting the BTU content of coal into the synthetic gas is between 65 and 80% (DOE, 1979).

Analysis by Booz, Allen and Hamilton, Inc. has postulated the existence of a large industrial market capable of using such gas. The magnitude of the estimated demand was found to be in excess of 3 quad Btus per year (DOE, 1979). Much of this market consists of process heat combustors such as those in the food and textile industries that cannot use direct coal, but could use such synthetic gas with little alteration other than the derating of the involved heaters. Commercial or pilot plant processes producing low and medium Btu gases are numerous such as Lurgi and Hygas schemes.

Synthetic liquids are produced from coal using three basic approaches -pyrolysis, indirect conversion and direct liquefaction. Pyrolysis involves heating coal to high temperatures in the absence of oxygen in order to release the volatile matter in the coal, thus producing a variety of petroleum liquids. In indirect conversion, coal is first gasified and then hydrogenated to produce distillates that can be further refined to gasoline. Direct liquifaction avoids the intermediate gasification step by use of temperature and pressure variations. Liquefaction processes tend to be about 65% efficient in converting the parent coal heat value to synthetic fuel. Several commercial processes exist, including Fisher-Tropsch, H-Coal, Solvent Refined Coal-II and

Donor Solvent (DOE, 1980). While some liquified coal derivative might be targeted to industry, the major motivation of this program is to provide an alternate supply of liquid fuels to the transportation sector.

TECHNOLOGY COSTS

As previously noted, the costs of synthetic fuels for industrial use are difficult to estimate with any degree of certainty. Nowhere in the DOE feasibility study was medium Btu gas shown to be less expensive than direct coal use (DOE, 1980). Moreover, the same study did not show synthetic gas as being competitive with natural gas on an annualized basis for investments made over the next ten years. As with several of the other examined technologies, significant market penetration of the synthetic fuels for industrial purposes cannot be expected before the year 2000. The most significant fact of an emerging synfuels industry for NGP coal would be the existence of the conversion plants themselves. It is estimated that a commercial sized facility producing 50,000 barrels of oil equivalent per day would require roughly ten million tons of coal per year (Cochran, 1976). A dozen or more plants of such size located in the Western U.S. could have a significant effect on demand for sub-bituminous coals but with questionable effects on limited regional water resources. The ultimate economy of synthetic fuels development is tied to the price escalation rates for substituted petroleum sources.

Economics of the Technologies

Although numerous studies have detailed the costs of various advanced coal combustion technologies, only one study (DOE, 1980) reviews all technologies on a comparative basis. Table 6-11 of that publication depicts the cost of heat on a levelized basis for the various alternatives. Cost data is in terms of feasible selling prices to industrial facilities including applicable transportation costs per 10^6 Btus of heat supplied:

Table 8.1
Cost Estimates for Advanced Coal Combustion Technologies

Alternative $\$/10^6$ Btu	Type	Conversion Effic.
Direct Coal $4.07	Boiler/ Process Heat	100%
Med. Btu Gas $5.46 - $7.03	Lurgi Gasific.	75%
Liquified Coal $5.72 - $9.47	Solvent Refined II	60%
Coal/Oil Mixture $4.66 - $7.16	COM	90%
AFBC $4.05 - $5.18	Limestone SO2 Removal	100%
Indirect Heat $5.95 - $7.14	Water Heat Transfer	90%

Source: DOE, 1980. Technical and Economic Feasibility of Alternative Fuel Use in Process Heaters and Small Boilers, DOE/EIA-10547-01, 6-11, Washington D.C.

Conclusions

The effect of the described advanced coal combustion technologies on the future industrial demand for NGP coal is significant. While direct coal is currently the most inexpensive method of heat delivery, COM and AFBC techniques seem to be reasonably promising technologies for the near future. It is expected that COM will be first choice for combustors currently burning residual oil because of the low capital costs necessary for conversion. However, production of COM for industrial use is uncertain. AFBC technology will become progressively more economically attractive to the point that it may replace boilers for many uses in the next century. Indirect heat will be useful only to the extent that snyfuel programs fail to offer low and medium Btu gas to the process heat sector. The financial viability of synfuels is exceedingly uncertain as evident in the wide range of variation of cost estimates summarized in Table 8.1. If it is plausible, such an industry would have substantial impact on demand for the vast fossil fuel resources of the Great Plains. A dozen commercial sized synfuels plants located in the region by the year 2000 would effectively double the current demand (120 million tons per year). The imposing capital expense of these plants would seem to indicate that strong favorable economic conditions will be a prerequisite for such large scale development.

The future price of conventional petroleum fuels will have a large impact on the market penetration rate of all technologies examined here. Penetration rates are apt to be slow unless world oil prices rise once more, economic conditions warrant increased capitalization or governmental regulations deny availability of natural gas to the industrial sector.

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CHAPTER NINE

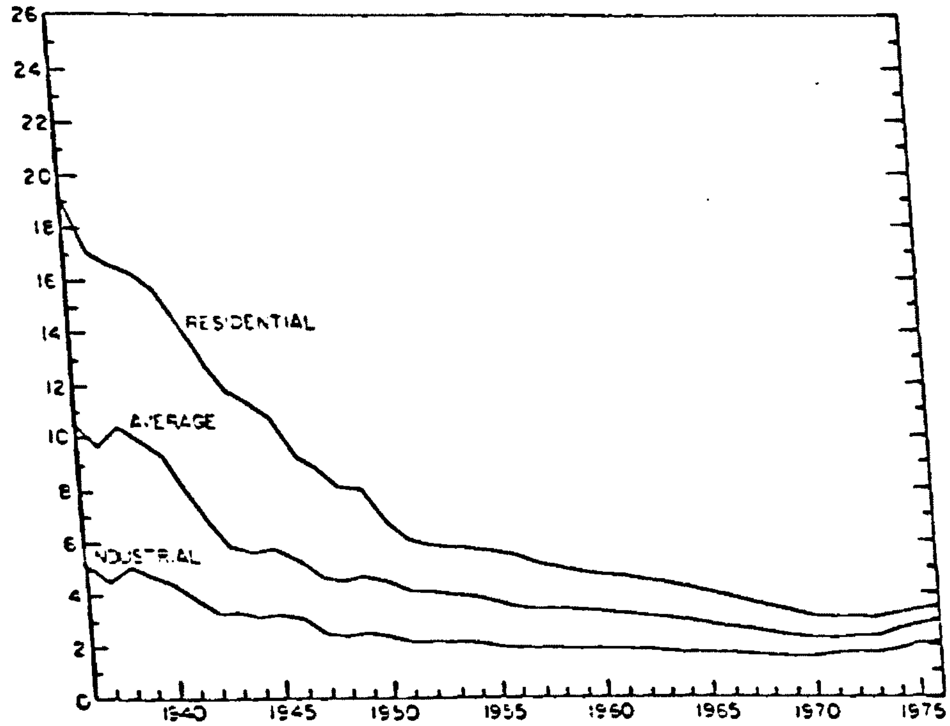
INDUSTRIAL COGENERATION POTENTIAL

Introduction

In 1920, 22 percent of all U.S. electric power was generated by industrial fossil fuel plants. These installations "cogenerated" this power by producing steam to create electricity and then using the byproduct steam for industrial purposes. By 1940 the proportion of the nation's electricity produced by the industrial sector had fallen to 18%, to 9% in 1960 and to a 4% in 1976 (U.S. Department of Commerce, 1975). Reasons for this decline include that electrical power demand has grown at a more rapid rate than has demand for industrial process steam combined with a long term decline of the real price of electricity delivered to large consumers (Figure 9.1). Additional influences include utility resistance to the idea of "buying" surplus industrial electrical production; the very high reates charged to industrial consumers for "backup power" and the very low rates offered for purchase of excess capacity. Williams (1978) described the situation:

> If an industrial firm wishes to cogenerate its own electricity and rely on the utility for backup supply, the standby charges imposed by the utility today for this backup service would usually be at least double the average price the industrial firm pays for electricity. In addition utilities have usually been unwilling to pay a fair price for electricity generated in excess of onsite needs. Typically, because an industrial owned cogeneration unit is not in the utility's base rate, the highest price a utility is willing to pay is a price equal to what it would cost the utility for just the fuel to produce the same amount of electricity. At such a price, it is often not profitable for the industrial firm to generate excess electricity.

Figure 9.1
ELECTRICITY PRICES IN CONSTANT (1976) DOLLARS



Source: Williams, R., 1978. "Industrial Cogeneration," in Annual Review of Energy, Vol. 3., Princeton University, Palo Alto, Calif.

The historical trend of declining electrical rates reversed in the early 1970's. This was due in part to increasing environmental control costs and the OPEC oil embargo of 1973. Electricity rates will probably rise faster than inflation over the long term because the marginal costs of new electricity generation capacity is considerably greater than the average price. This is particularly true in the Pacific Northwest where additions to generation capacity will be predominantly coal fired while the proportion of hydroelectric capacity declines.

There is evidence that increases in energy conversion efficiency of fossil fueled central power plants are reaching limitations exacted by the laws of thermodynamics. These same laws suggest a potential increase in energy conversion efficiency for cogeneration of electricity by industry that may only be matched by future advanced combustion technologies. Unlike these technologies, cogeneration electrical production is currently feasible. Economic feasibility has been constrained by utility purchase policies that have discouraged such applications and falling prices of electricity. Legislation passed in 1978, the Public Utility Regulatory Policies Act (PURPA), and forecasted increases in real electricity price should provide increasing incentive for industrial cogeneration. Consequently, the basic energy conversion efficiency of this process may lead to a future where significant new electrical generation capacity is cogenerated.

<u>Legislative Basis</u>

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) contains several important provisions in regard to industrial cogeneration. The act requires utilities to both sell backup power to cogenerating facilities and also to purchase excess electrical energy produced, at equitable rates. This requires that in selling electric power to cogenerating facilities, utilities do not discriminate against such facilities with regard to price. It also requires that the rate offered to cogenerators for their electricity correspond to "the incremental cost of alternative electric energy" - such that the price offered is similar to what a utility would pay to purchase power from another utility.

For the purposes of the act, cogenerating facilities may not exceed 30 MW. The remaining subsections of the act exempts such plants from the Federal Power Act and the Public Utility Holding Company Act and describes implementation and enforcement of the provisions.

An important implication of the act is that the historical economic bias against cogenerators promulgated by utilities will not be continued, both with regard to pricing of "backup power" to such facilities or to a just and reasonable price for power generated in excess of plant specific needs.

Theoretic Structure

It is widely agreed that conservation of energy use in the industrial sector must concentrate on the specific thermodynamic processes by which work is obtained. It is possible to survey the potential for coal use in various applications, and to identify those processes of which energy costs are a substantial portion of delivered costs to the market. However, empirical evidence obtained from a survey of industrial consumption of NGP coal in 1981 and "residual sales" from mining contracts found that this use was three to five percent of total NGP production (c. 120 mty). The other 95-97% of this tonnage consisted of utility consumption for the purpose of electricity generation.

It is assumed that utilities will act in a rational fashion to minimize their fuel costs for the energy conversion process. Thus the history of the utility industry should evidence a trend of increasingly efficient electrical conversion processes and equipment. As expected, thermal efficiencies of steam electric power plants have increased by nearly an order of magnitude since the turn of the century. However, since 1960 there have been only slight increases in the efficiency of the conversion process. The economic pursuit of economies of scale and engineering innovation has run its course for conventional conversion technologies.

Ultimately, the theoretical potential of the conversion process is limited by the first and second laws of thermodynamics. The first law efficiency of an energy conversion process is defined:

$$E = \frac{Qmax - Qmin}{Qmax} \times 100$$

where E = efficiency in percent

$Qmax$ = heat taken in

$Qmin$ = heat released

Thus, if we examine a fossil fuel power plant, we find that steam temperatures are on the order of 1000°F at the inlet while the exit temperatures are about 80°F, or converted to Kelvin:

$$E = \frac{810-300}{810} \times 100 = 63\%$$

This is the theoretical maximum thermal efficiency for a heat engine with these design temperatures such as envisioned by Carnot in 1824. Actual optimal performance of a steam turbine in converting coal to electricity is considerably less at about 45% (Priest, 1979). This is because of the various losses in the conversion process from combusted coal, to steam and to electricity.

The direct use of coal in an industrial boiler fares better in this respect since there is only one conversion process - that from burning fuels to steam. The coal combustion temperatures are about 3000°F with process steam temperatures of about 300°F or

$$E = \frac{1922-422}{1922} = 78\%$$

Thus, coal fired boilers potentially have a first law thermal efficiency of about 80%. In practice, this may be less since process steam utilization (Qmin) tends to be used at about 300°F (422K.) instead of 80°F.

The first law efficiencies only describes the success of the energy conversion process - it tells nothing about the entropy of the energy used in the process. This is the quality of energy used, compared with the quality necessary for the work accomplished. As such the second law efficiency is a comparative measure of the success of the conversion process in terms of theoretical performance. It is defined as the available energy input over the actual heat energy required to accomplish a task, or:

$$E = \frac{W_{min}}{W_{act}} = \frac{Q}{W_{act}} \frac{1 - \frac{Q_{min}}{}}{1 - \frac{Q_{min}}{Q_{square}}}$$

where:

Wmin = theoretical minimum amount of available work needed to perform the task

Wact = actual amount of available work consumed in performing the task

The second law efficiency of the electrical steam turbine is calculated:

$$E = 47 \frac{1 - \frac{300}{810}}{1 - \frac{300}{2000}}$$

$$E = 35\%$$

Or, 65% more energy is consumed by the conversion process than was the minimum required in an ideal heat engine. The second law efficiency for the industrial boiler is calculated:

$$E = 78 \frac{1 - \frac{300}{420}}{1 - \frac{300}{2000}}$$

$$E = 26\%$$

Even though the first law efficiency of the industrial boiler is greater than that for the thermal electric conversion process, when the appropriate use of fuel is examined in light of the second law of thermodynamics, it is found that coal combustion to produce steam of relatively low thermodynamic qualify is a less efficient process (Shipper, 1976).

One way around this problem is industrial cogeneration. In this process high temperature and high pressure steam is first used at the plant to generate electricity. The residual steam products from this process is then used as process steam at the plant. Cogeneration has the advantage of a first and second law efficiency greater than either of the two separate processes of utility electrical generation or process heat production (Keenan, Gyftopoulos and Hatsopoulos, 1974). In addition cogeneration systems often require less capital than is required for conventional utility plants resulting in lower electricity costs for industry. It also provides greater flexibility in planning future electrical peak demand generating capacity. Such use of this "waste heat" obviates the need for cooling towers or thermal pollution of rejected heat from power stations. Whereas 68.5% of U.S. fossil fuels used in production of electricity are lost as waste heat, only 47% is lost in similar processes in Sweden because 24% of energy consumed was utilized for cogeneration or space heat utilization purposes (Shipper, 1976). This heat discharged from U.S. power plants represented one fifth of total national fuel consumption in 1978.

In order to calculate the second law efficiency of an industrial cogeneration system, we must calculate "Wmin" for the process of creating electricity at the facility and then using remaining heat for required steam production. This is calculated:

$$Wmin = mv\ (p-p_1) + mcp\ [(T_{hot} - T_{cold}) - T_{amb}\ \ln (\frac{Thot}{Tcold})] + ml\ (1 - \frac{Tamb}{Thot}) + E$$

where:

m	=	pounds of saturated steams
T_{hot}	=	temperature of steam
p	=	pressure of steam
v	=	specific volume of feedwater
C_p	=	specific heat of feedwater
l	=	latent heat of vapurization of water at T_{hot}
T_{cold}	=	boiler inlet water temperature
T_{amb}	=	temperature of ambient environment
E	=	byproduct electricity

There are a number of possible industrial cogeneration configurations, such as gas turbines (Brayton Cycle), steam turbines (Rankine Cycle) or diesel engines. However, because of the engineering configuration necessary, only the steam turbine can use coal as a fuel. The Rankine cycle is the appropriate application in a "back pressure" turbine system. Coal is burned to raise steam in a boiler to high pressure (850-1450 psig). The high pressure steam is then used to power a turbine that produces electricity and the remaining low pressure (50-300 psig) steam is used for the involved process steam application. This method differs from a conventional steam turbine system in that the steam exits the system at considerable pressure and temperature unlike utility processes where steam exits the turbine into a condenser at 100°F at 1 psia and the waste heat is rejected to the environment. This reduces the first law efficiency of the conversion process to electricity from 30-40% to 10-15%, but both electricity and useful process heat is obtained from the same facility. The combination results in a more efficient first law efficiency than either of the two separate plants. The fuel required to produce electricity beyond that of the normal process heat production is about 4,500 Btu/kWh instead of the usual 10,000 Btu/kWh rate that is typical of fossil fired central generating plants (Williams, 1978). Table 9.1 details the characteristics of two such cogeneration plants along with comparative second law efficiencies as calculated above for both separate and cogenerated configurations.

Table 9.1
Comparative Cogeneration Energy Conversion Characteristics

Type	Steam Pressure (psig)	Kwh/10^6Btu Steam	E to Elect.	Heat Rak_a	Second Law E_b
Rankine Steam	50	190	.16	4,550	.40/.32
Rankine Steam	150	50	.13	4,550	.42/.35

[a] - fuel required to produce electricity (kWh) in excess of that for process steam production alone. Boiler E = 80%.

[b] - second law efficiency of congeneration plant and separate steam and electricity generation facilities.

Source: Williams, Robert, 1978. "Industrial Cogeneration," Annual Review of Energy, 1978. Princeton, University, Princeton, NJ. Vol. 3, p. 320.

Consequently, the fuel saved per unit of process steam demand is proportional to the displacement of fuel use at utilities to generate the produced electricity. The fuel savings rate for the cogeneration scheme is calculated per Btu of steam produced:

$10{,}000 - 4{,}550$ Btu of coal/Kwh x (70 x 10^6 kwh per Btu of steam) = .38 Btu/Btu

Thus in the modeled boiler (175 10^6 Btu/h) we assume a 78% first law efficiency = 136.5 x 10^6 Btu of steam per hour.

$136.5 \times 10^6 \times .38 = 51.9 \times 10^6$ Btu/h

This corresponds to a 38% fuel savings over the two separate processes. If one examines only the first law efficiency of separate or cogeneration schemes it can be shown that approximately 15% of the available energy will be converted into a desirable form (electricity) than if steam alone was produced (G.A.C., 1980). Given the above configuration the modeled boiler would produce 8.75 megawatts per hour of operation. Assuming a conservative 35 mills/kwh in avoided central power generation costs, this would amount to revenues of $306 for the plant, per hour of operation.

Economics of Cogeneration

The economic viability of an industrial cogeneration facility is contingent on several factors.

1) The size of the steam plant and potential economies of scale.

2) The capacity utilization of the plant - large capacity utilization percentages being most favorable.

3) Whether the cogeneration will be new facility or retrofit and appropriate capital costs.

4) The cost of electricty from other sources.

5) The cost and stability of fuel price.

6) The cost of additional operation and maintenance.

The size of the steam plant in an industrial plant has strong effects on resulting electrical power generating economies of scale. Table 9.2 depicts the economies of scale involved in the capital cost of steam turbine cogeneration systems exclusive of boiler components. The economy of scale is on the order of .8.

Table 9.2
Capital Costs for Power Generation Using a Coal Fired Steam Turbine Cogeneration System+

Size of Facility (MW)	Cost ($1980/kW)	Total Cost $\$1980 \times 10^6$
5	451.0	2.25
10	359.0	3.59
20	285.0	5.70
50	211.0	10.54
100	167.0	16.74

+ does not include costs of steam plant.
Source: G.A.C., 1980, Industrial Cogeneration, EMD-80-7, Washington, D.C., p. 49.

Other estimates underscore the relative uncertainty of this cost estimation procedure. For example, the Thermo Electron study (Stone and Webster, 1976) claims that just the cogeneration system for the 5 MW configuration depicted above would cost more than twice as much ($1,030/KW). It follows that sensitivity must be performed on capital costs. Even so, this does not compare poorly with estimated costs of central power plant capital costs of $800-$1,200/KW for new coal powered facilities (Electrical World, 1977).

The modeled boiler (175 x 10^6 Btu/h) produces about 140,000 lbs. of steam per hour @ 150 PSIA, 325°F. This corresponds to a cogeneration capability of about 7 MW using a steam turbine system. Using an economy of scale of .8 and estimates for a 7 MW system from G.A.C. (1980), Limaye, 1983 and Pickel (1978) total additional cost for the modeled boiler were estimated to be between $2.90 million and $7.21 million.

This range of costs is used to develop the annualized cost of producing electricity from cogeneration.

Fuel costs for the cogenerated electricity is based on the effective heat rate of the cogeneration steam turbine system being 4,550 Btus per generated kilowatt hour (Solt, 1978). This means that the electrical generation system will require 4,550 Btus input per Killowatt generated above the requirement for the boiler itself. Since the generation unit is assumed to have a capacity of 7 MW this corresponds to a firing rate of 31.9 x 10^6 Btus per hour that is attributable to the cogeneration system. Since there is some derating of steam availability, it is assumed that in the reference case boiler ($175 * 10^6$ Btu/hr) the capacity utilization rate is increased from 60% to 70% to make up the difference. Coal costs are taken from data in Chapter 5. The industrial coal market model is modified to estimate the capital, fuel and O&M components of the generated electricity. Parameters are set equivalent to the analyses in Chapter 5 unless otherwise noted.

Based on Williams (1978) and Limaye (1983) operation and maintenance costs are estimated to be about $.004 per kilowatt hour in 1980 dollars. This results in a first year O&M cost of about 1.75 million dollars that is attributable to the cogeneration plant.

The range of capital costs if $2.90 to $7.21 million for the 7 MW generation plant. This is over and above the $15.49 million cost of the boiler facility. The fixed charge rate is 9.09% as used previously.

In Table 9.3, the total delivered cost of generated electricity from old and new utilities against cogenerated electricity are developed.

Table 9.3
Annualized Costs of Electricity to Industrial Sector (mills/kwh)
$1980

Component	Utility Average	Utility New Coal	7 MW Cogen
Capital	-	10.61	6.14-15.27
O&M	-	2.43	4.60
Fuel	-	13.55	6.98
Busbar Cost	16.73	29.59	17.72-26.86
Trans. Cost	10.46	7.72	N/A
Deliv.Cost	28.04	34.31	17.72-26.86

Sources: Williams, R., 1978. "Industrial Cogeneration," in Annual Review of Energy, Vol. 3., Princeton University, p. 313.
Duffield et. al., 1982. Projections of Coal Demand From the Northern Great Plains through the Year 2010, University of Montana, Missoula, MT.
Limaye, D.R., 1983. Cogeneration: Technical and Economic Considerations, Synergic Resources Corp., Bala Cynwyd, PA.

As shown, the coal fired steam turbine system is only marginally competitive with the average cost of electricity delivered to the industrial sector, while it is significantly cheaper than the cost of new capacity. This point is problematic. It will be difficult to encourage cogeneration until significant savings from electrical energy costs can be demonstrated. Since the delivered price of electricity to industry is the average of less expensive old facilities and more expensive new plants, the average cost is considerably lower than the marginal cost of new generating capacity. Since it is doubtful that most industries can produce substantial quantities of power for sale using the Rankine Cycle (G.A.C., 1980), the initial promise for co-generation systems lies with the more electrically prodigious methods of gas fired turbine and diesel cogenerating schemes. However, as average electricity costs increase with old plant retirement and more major fuel burning installations are prohibited from burning oil or natural gas (PIFUA, 1978), the coal-fired cogeneration scheme becomes more attractive. Industrial plants with large steam demands will be the most amenable to cogeneration given the demonstrated economies of scale. Even now, it is more a cost effective as well as more efficient means of increasing electrical generating capacity.

Conclusions

The economies of cogeneration are most favorable in the petroleum refining, paper and chemicals industries where industrial plants have high steam demand and large capacity factors. Generally, gas turbine or diesel cycles are more favorable than a coal fired steam turbine process in terms of produced electricity. Cogeneration represents a more thermodynamically efficient form of fossil fuel utilization than does use of coal for separate processes of heat production and electricity energy conversion. Cogenerated electricity also represents a less expensive alternative to new generating capacity than does new central station utility power plants. The factor that most retards utilization of this technology now - that of lower average costs of electricity delivered to the industrial sector - may disappear in the next decade as more new expensive capacity is added and older, less expensive facilities are retired.

The argument for combined industrial parks with several plants using a single high utilization energy facility seems logical in lieu of the economies of scale possible with large scale cogeneration. It is feasible that a significant portion of new electrical generating capacity in the future may be fueled by industrial conversions to this process.

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CHAPTER TEN

NGP COAL EXPORT POTENTIAL

Introduction

Current markets for the Northern Great Plains coals of the Powder River Basin consist predominantly of long-term mining contracts with Western and Midwestern utilities. Research has established that electrical demand growth rates will play a significant role in determining the demand for NGP coal in its least-cost market area (Harr and Lee, 1981). This area's boundaries are strongly influenced by distance of plant to supply source because of large rail transport costs involved. Other important determinants of the least-cost market area are mining production costs, the Btu content of the coal by weight, and emissions controls, which vary with fuel sulfur content. It is also expected that the large shift away from nuclear electric plant construction in the market area will give the majority of new plants to coal (Snow, 1981).

Other research has examined the prospect for industrial use of Great Plains coal and the resulting effect on demand. As evidenced by the small number of industrial contracts, industrial use of coal is constrained by interfuel price competition, particularly with natural gas. Although coal was shown to be the least cost fuel choice, its advantage is marginal and is only realized after a long pay-back period. The potential for industrial use of NGP coal is almost certainly greater than that current existing, but not nearly as great as coal's potential in utility use. This means a weak demand for NGP coal from industry through the 1980s, with the outcome strongly dependent on natural gas prices and environmental and fuel use regulations.

Two other eventualities may affect NGP coal demand. One is the postulated demand for western coal from corporations producing synthetic fuels. Examples of these are plans by the Wyoming Coal Gas Company and Texaco, Inc., to open gasification plants in Douglas and DeSmet, Wyoming, with possible requirements of 9 to 12 million tons per year (mty) each. However, the current status of these two NGP projects is unclear.

This Chapter addresses the possible effect on demand for NGP coal posed by a rapidly increasing coal import demand from Far Eastern industrialized countries. As will be seen, the potential for export of NGP coals is strongly influenced by many of the same factors affecting the domestic coal market boundaries.

When studying the economic competitiveness of Powder River coal for Eastern export, the competing sources of coal are not only those proximate to the West Coast in the U.S. but also coals from other international supply regions such as Australia, South Africa and Canada.

The cost minimization strategy is only one of several considerations. Other concerns include coal combustion characteristics, reliability of supply, diversification of sources, and efforts to promote competition. (WESPO, 1981).

This Chapter evaluates the potential of NGP coal for export in terms of its effects on future demand. Market share analysis is based on least-cost choice with a bias for market source diversification.

Historical Perspective

Between 1960 and 1980 the amount of coal traded in the world market more than doubled from 113.3 million short tons (mst) to 252.4 mst (WOLCO, 1980). The majority of this increase was due to a greater demand by international steel industries for metallurgical coal. During the same period, world steam coal trade remained fairly constant, although shipments to developed Organization for Economic Cooperation and Development (OECD) nations actually declined as petroleum prices dropped relative to coal prices. Along with this price change, the cost of transporting coal and growing environmental concerns, coal's share of the international primary market fell from 49% in 1940 to a low of 29% in 1973. However, steam coal exports are expected to slowly increase in response to increased world oil prices.

Countries in the Far East, particularly Japan, had become economically dependent on foreign oil since World War II, having little domestic supply of their own. By 1973, Japan was the third major petroleum-consuming nation, behind only the U.S. and the Soviet Union (Allen, 1981). Given supply shortfalls and price increases, Japan and South Korea have attempted to increase efficiency of energy use and to promote substitution of other fuels for expensive petroleum. Accordingly, the Pacific Rim countries (Japan, South Korea, Taiwan and Hong Kong) have attempted to increase domestic production of coal and have instituted ambitious programs to increase coal imports and substitute such fuels for current petroleum use. Table 10.1 indicates how these countries have increased their coal import demands since 1970.

Table 10.1
History of Pacific Rim Coal Import Demand, 1960-1979 (mst)

Country	1970	1970	1975	1980
Japan	9.1	55.3	68.5	64.5
South Korea	--	--	.7	7.0
Taiwan	.2	--	.1	5.9

Source: Coal International, 1979, Vol. 2, No. 7, p. 16.

Unlike European coal import markets, sources of import coal for Pacific Rim nations are generally far from the consuming countries. In the past, most of these imports have been for metallurgical coals used in the steel industries. The major exporters to the Pacific Rim have been the United States, Australia, South Africa, and Canada (ICETF, 1981). Table 10.2 presents the 1979 coal import information for the Pacific Rim nations by exporting countries.

Table 10.2
1979 Pacific Rim Coal Imports (mst)+

Exporters	Japan	Korea	Taiwan	Other
U.S.	14.9 (95-100)	1.2 (65)	.3 (100)	4.1 (90)
Australia	29.4 (95)	2.5	1.9	.6
South Africa	2.9 (95)	--	--	--
Canada	10.9 (100)	1.0	.1	1.2
Other	3.8 (95-100)	2.0	3.3	3.1

Source: DOE, 1981, Interim Report of the Interagency Coal Export Task Force, DOE-FE-0012, January, 1981.

+Percent of total that was metallurgical coal is shown in parentheses.

As seen in Table 10.2, metallurgical coal comprised over 90% of the Pacific Rim import trade. However, recent slowing in world economic growth is expected to hold the metallurgical coal market relatively constant, while demand for thermal coal imports is expected to increase rapidly in response to multiple increases in world petroleum prices. The WOLCO study (Wilson ed., 1980) predicts an increase in steam coal as a percentage of world coal trade from 33% in 1977 to between 50% and 70% by the turn of the centry. This is mainly because thermal coal has become a significantly cheaper fuel for utility and large industrial boilers even when costs of particulate control and flue gas desulfurization are included.

The least-cost supplier of thermal coal to the Pacific Rim market is not the United States. Generally incompressible factors, such as less inland and maritime transport distances for Australian and South African coal, will exclude U.S. coal as least-cost choice (Wilson, 1980). However, interest in diversification of supply and competition in Japan has established the U.S. as a marginal thermal coal import source.

Pacific Rim interest in U.S. coals strongly favors Western low-sulfur coals that are closest to Pacific markets (ICETF, 1981). Of major Japanese interest is reliability of sources and extensiveness of the resource base to support long-term contracts (WESPO, 1981a). Although the Great Plains coal resource is distant from ports, it is vast and provides a relatively elastic supply.

Until very recently, foreign export of this coal has not been a seriously entertained notion. In a 1962 thesis on international coal trade, Monell observed that "the region contains vast quantities of coal that are relatively unimportant at present. . . although reserves may have a greater use in the future."

There are currently no exports of NGP coals, although the capability does exist and the coal is of the low-sulfur type that Pacific Rim markets desire. An evaluation of the NGP export potential necessarily requires an estimate of Pacific Rim demand, the market share that the U.S. could expect to capture, and the percentage of the U.S. share that NGP might expect to capture, assuming cost minimization behavior by the purchasers.

The Pacific Rim Market

The potential export market for Northern Great Plains coal is located in Japan, the Republic of South Korea, Taiwan, and Hong Kong. These nations are attempting to substitute steam coals for expensive petroleum that they must purchase off the world market.

Japanese development of import steam coal trade is being led by nine privately owned power companies and the Electric Power Development Company (Tajiri, 1981). Steam coal imports will be led by these Japanese utility groups, although the Japanese steel industry is also in the process of substituting coal for furnace oil using a coal oil slurry mixture (Nemoto, 1981).

Domestic energy production in Japan in quite limited. In 1977 Japanese steam coal production yielded only 10 mst. These coals are of meager quality and lie concentrated in the southernmost island of Honshu and to a lesser extent on the northernmost island of Hokkaido. Numerous studies have failed to provide evidence that these yields might realistically increase (Wilson, 1980). In 1977 Japan imported some 2 mst of steam coal from Australia for utility consumption; in 1980 7.1 mst were imported. However, Japanese steam coal import needs are forecasted to increase rapidly in all predictions. The WOLCO study predicts an average annual growth rate in demand of 15.3% annually to the year 2000. Hence their convervative estimates show 7 mst of steam coal imported by 1985, 26 mst by 1990, and 58 to 80 mst by 2000. The Interagency Coal Export Task Force predicts a similar increase for Japan, although somewhat more rapid than the WOLCO forecasts. ICETA predicts a demand of 25.3 mst by 1985 with the possibility of 118.5 mst by 2000. Masama Tajiri, Senior Advisor to the Tokyo Electric Power Co., has stated that 8% of the total Japanese energy requirement in 1990 would be met by imported coals consisting of 57 to 63 mst. The greatest part of the projected coal demand will be from construction of additional coal-fueled thermal electric power plants. Coal use in industry, especially cement, paper and steel, is expected to play a secondary role in demand (Nemoto, 1981).

There are other difficulties for coal use in Japan, however, since environmental restrictions in its burning will require FGD equipment similar to that mandated in the U.S. Unlike the other Pacific Rim countries, use of low-sulfur coal as a compliance fuel is not an available option. Even so, it is expected that to address enviornmental regulations, Japanese import steam coal demand will focus on low-sulfur coals.

Another important determinant of Japanese import coal demand is the percentage of total primary energy used that is nuclear electric. In 1979, 13% of their primary energy was nuclear-generated. Official projections predict 30% of their total energy in 1990 to be nuclear (Tajiri, 1981). However, it must be noted that the International Energy Agency and U.S. DOE forecasts of available Japanese nuclear capability by 1990 are significantly less optimistic. An additional source of uncertainty is how much liquid natural gas (LNG) Japan may import for its energy needs in view of its stringent environmental standards for many areas.

Japanese import coal demand projections will be strongly determined by additions to electrical generating capacity. According to ICETF and WOLCO forecasts, total energy growth in percent per year for Japan is expected to increase at 4.0% to 4.5% per year to the year 2000. Electrical generating capacity is scheduled to increase to 7.40 x 10^{11} kWh by 1985 to 1.21 x 10^{12} kWh by 2000 (ICETF, 1981). Much of the increased demand is expected to be nuclear-generated capacity and coal imports. Nuclear development is potentially a key issue in determining Japan's overall import steam coal demand. Reductions in nuclear capacity might increase demand, whereas increases in LNG imports would obviate needs for additional steam coal.

Table 10.3 summarizes official Japanese predictions of the 1990 fuel mix to fulfill Japan's total energy requirements. Table 10.4

depicts the current fuel mix for Japanese utilities and how this mix is expected to change by 1990.

Table 10.3
Japan's Projected Fuel Mix for 1990

Fuel	Rate of Consumption	Percent of Total
Domestic petroleum	160 BBL/day	1.4
Domestic coal	20 mty	2.0
Geothermal power	130,000 BBL/day	1.0
Synfuels/biofuels	660,000 BBL/day	5.5
Hydropower	53 million kwh/year	4.6
LNG imports	45 mty	9.0
Nuclear power	53 million kwh/year	10.9
Imported coals	60 mty	15.6
Imported petroleum	6,000,000 BBL/day	50.0
		100.0

Source: Tajiri, M. 1981. "Expansion of Steam Coal Utilization in Japan." Lake Tahoe, Nevada: Second U.S.-Japan Coal Conference, p. 536.

Table 10.4
Japan's Percentage of Electricity Generated by Fuel in 1990

	1979	1990	% Change ±
Nuclear	13	29	+16
Coal	4	10	+ 6
LNG	14	18	+ 4
Hydro	18	17	- 1
Oil	51	26	-25

Source: Tajiri, M. 1981. "Expansion of Steam Coal Utilization in Japan." Lake Tahoe, Nevada: Second U.S.-Japan Coal Conference, p. 536.

Table 10.5 presents four independent predictions of Japanese import steam coal demand for the next 20 years. WOLCO predictions tend to be lower than Japanese forecasts or those of ICETF. Part of this is explained by a Japanese decision to rush coal use for steel and paper products.

Demand for coal by the cement industry alone was scheduled to reach 10 mty by late 1981 (Nemoto, 1981).

Table 10.5
Japanese Import Steam Coal Demand Forecasts+

	WOLCO	IEA	ICETF	Tajiri	WESPO
1985	6-7	14	22	29	34.0
1990	35-44	33	42	57-63	63-69
2000	53-121	77	86-103	--	--

Source: Wilson, C.L. 1980 (WOLCO study); ICETF, 1981; Tajiri, M. 1981; and WESPO, 1982.

+Forecasts stated in million metric tons coal equivalent (mtce) (2.05 x 10^9 lbs @ 12,600 Btu/lb).

South Korea's energy needs are forecasted to increase even more rapidly (6% annually) than those of Japan in the studied period. Koreans have already undertaken longterm contracts with Australia and South Africa for steam coals. The Korea Electric Company has been studying the possibility of purchasing U.S. coals, but no firm commitment has been made (WESPO, 1981a). Korea's coal imports have increased from .7 mst in 1975 to over 7 mst in 1979. Such rapid growth is projected to continue uninterrupted, as there are no significant domestic coal, or other energy reserves, in Korea. Table 10.6 depicts WOLCO and ICETF predictions of South Korean import steam coal demand for 1985-2000.

Table 10.6
South Korean Import Steam Coal Demand Forecasts (mtce)

	WOLCO	ICETF	WESPO
1985	14	8	13-15
1990	30	14	19-20
2000	54-65	44	-

Source: Wilson, C.L. 1980. Coal: Bridge to the Future. Cambridge, Mass.: Ballinger Pub. Co., pp. 236-237, and ICETF. 1981. Interim Report of the Interagency Coal Export Task Force, Table 3-8, WESPO, 1982.

Significant disparity exists between the forecasts based on differences in underlying assumptions of world economic growth rates. Also any reconciliation between North and South Korea could have major effects on these scenarios since North Korea has large coal reserves.

Taiwan also has negligible coal production capability. There are some marginal domestic reserves in the country that might reach .7 mst per year by 1985 according to ICETF. However, the projected energy growth rate from the country is 4.8% for the forecasted period, with no nuclear capacity yet in evidence (ICETF, 1981). Accordingly, Taiwan steam coal imports in 1979 totaled 5.3 mst mainly for electric power generation from coals from Australia and South Africa. Table 10.7 depicts WOLCO and ICETF projections for the forecasted period.

Table 10.7
Taiwan Import Steam Coal Demand Forecasts (mtce)

	WOLCO	ICETF	WESPO
1985	7	3	2
1990	12	14	18-27
2000	69-88	36	-

Source: Wilson, C.L. 1980. Coal: Bridge to the Future. Cambridge, Mass.: Ballinger Pub. Co., pp. 108, and ICETF. 1981. Interim Report of the Interagency Coal Export Task Force, Table 3-8.

Table 10.8
Import Coal Demand Forecast Average and Percent Share of Total by Country (mtce/yr)+

	Japan	S. Korea	Taiwan	Hong Kong	Total
1985	18 (49)	11 (30)	5 (14)	3 (8)	37
1990	44 (52)	22 (26)	13 (15)	5 (6)	84
2000	86 (43)	51 (25)	57 (28)	8 (4)	202

Source: ICETF. 1981. Interim Report of the Interagency Coal Export Task Force, Table 3-8, and Tajiri, M. 1981. "Expansion of Steam Coal Utilization in Japan and Expectations for U.S. Western Coal", Lake Tahoe, Nev.: 2nd U.S.-Japan Coal Conference.

+The number in parentheses indicates the percent share of total demand.

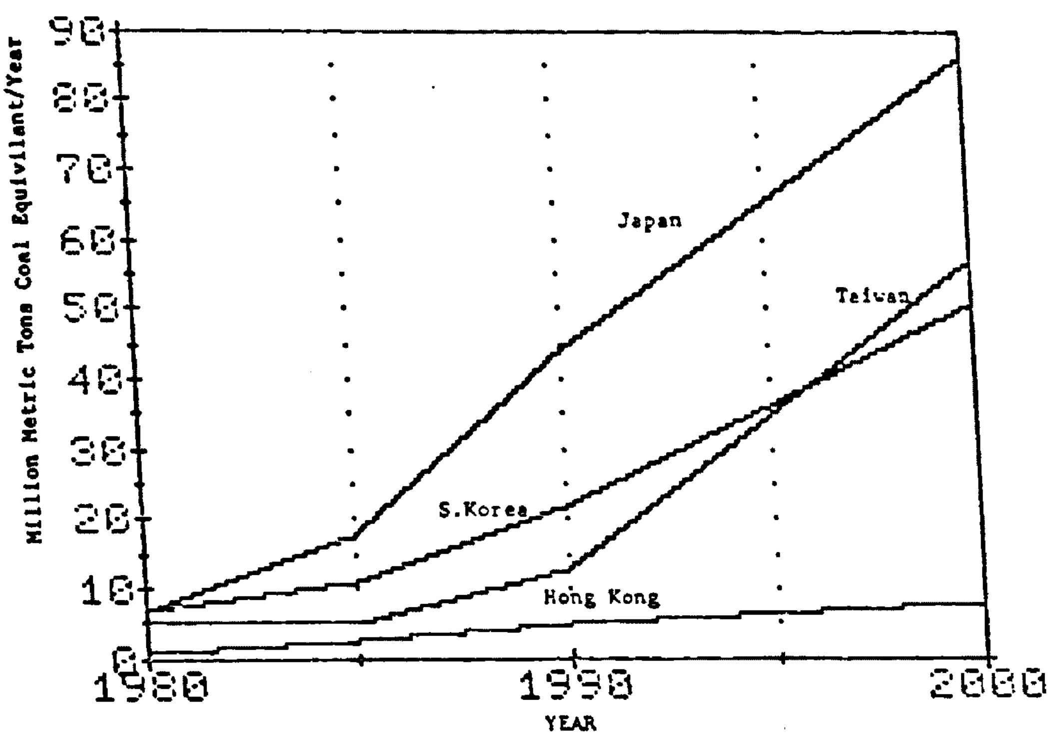
Figure 10.1 illustrates this data and depicts the rapid rise in Pacific Rim coal demand after 1990. The surprising growth in Taiwan's demand forecasted for this period seems somewhat suspect.

International Coal Sources

Unlike coal suppliers in the NGP coal market model described by Lee and Harr (1981), NGP export coals must compete economically with other international sources for the Pacific Rim market. They must also

Figure 10.1

PACIFIC RIM IMPORT STEAM COAL DEMAND



Source: ICETF, 1981. Interim Report of the Interagency Coal Export Task Force, DOE/FE-0012, Washington D.C.

compete with domestically produced coals in the U.S. in order to capture any share of the predicted markets. Since the Japanese have stated that U.S. delivered coal prices lie on the boundary of acceptable levels for import coals (Tajiri, 1981), competition within the U.S. for those markets is apt to be vigorous. The major factors in this competition are basically incompressible. Inland distance to port is the most important factor, followed by production costs, heat content of fuel and ocean distances. Furthermore, the distance advantages that exist to sources other than the U.S. in international markets are apt to constrain the U.S. share, especially if Pacific Rim economic growth rates lag behind projections (Wilson ed., 1980).

The major international sources with which the U.S. can expect to compete for the market are Australia, South Africa, Canada, and China. Factors important to this international competition are production costs, reserve characteristics, and reliability and transport distances. Production reliability and, to a lesser extent, production costs are the only variable costs. Production reliability is influenced by government control of the coal industry, the national political environment, the existence of mining unions, and the extent of the reserves available for contract. Production costs are dictated by the location of the coal resource (labor productivity) and the technology associated with its removal. Production costs are generally lowest for strippable surface reserves and increase with underground and deep underground operations (Smith, 1981). Inland transportation distance is easily the most important variable because of the high costs for rail movement of coal (Lee and Harr, 1981). Ocean transport is not nearly so energy-intensive as the inland mode, although it can be significant in excluding Eastern U.S. coals from the Pacific Rim market. Both of these transportation modes are affected by the Btu content of the fuel by weight, higher heat content fuels being more competitive.

Table 10.9 lists the extensiveness of the available coal reserves and resources in the various countries that may export to the Pacific Rim. The geologic resource numbers are less certain than other estimates. Table 10.10 lists other characteristics that will influence their competitive position relative to the market.

Table 10.9
International Coal Source Potential for Export (mtce)

	Geologic Resources	Economically Recoverable Resources	Export Potential
Australia	600,000	32,800	160-200
S. Africa	72,000	43,000	75-100
Canada	323,036	4,242	47- 67
China	1,438,045	98,883	30
U.S.	2,570,398	- 166,950	200-350

Source: Wilson, C.L. 1980. Coal: Bridge to the Future. Cambridge, MA: Ballinger Pub. Co., p. 161.

Table 10.10
Pacific Rim Export Coal Characteristics

Supplier	Heat Content (Btu/lb)	Mine Type	Productivity Tech/ Reliability	Sulfur (%)	Inland Trans. (mi)	Ocean Trans.+	FOB Mine ($/ton)
Australia	Bit. 11,500	Surface	High mod.	.5	100-225	4,000	20-25
S. Africa	Bit. 10,500	Deep	Med. low	1.0	300	8,700	15-25
Canada	Bit. 9,000	Surface	High high	.5	650-750	4,800	20-25
China	Anth., Bit. 8,000-12,000	Deep	Low low	1.0	800	1,500	10-15
U.S.	Bit., Subbit. 8,700-11,500	Surface Under	High high	.5	500-1,100	4400-4800	17-25

Source: ICETF. 1981. Interim Report of the Interagency Coal Export Task Force, Table 5-5.

+Based on distances to Japan in nautical miles.

The following sections detail unique attributes to the various exporting countries that might influence their use by the Pacific Rim.

AUSTRALIA

In 1979, Australia exported 44 mst of coal, much of it metallurgical earmarked for the Pacific Rim. Reserves are abundant, of high quality and are usually capable of being surface mined. Labor disputes have been more prevalent at mines producing for the export market, reportedly because of public opinion concerning foreign investments. The mining operations are technologically advanced and capable of rapid expansion.

SOUTH AFRICA

Exports from South Africa were 25.8 mst in 1979, mostly of steam coals. Coal is South Africa's only indigenous fossil fuel, and there is some question about serious expansion of exports. The coal has fairly low heat content, is high in ash, and has a sulfur content of about 1%. Mining methods are labor intensive with low production costs due to low wages and the predominance of underground mining. As a result, the labor situation in South Africa is unstable, and government control over exports is complete. Any increases in wages are likely to increase production costs.

CANADA

Almost all of Canada's coal reserves are in the western part of the country centered in Alberta and British Columbia. In 1979, 15.3 mst were exported; Japan received 76% of the total, although all the coal was reportedly for metallurgical use. There are ample subbituminous reserves in Eastern Alberta that are favorable to surface mining but are far from ports. Development of mines for export may require substantial increases in rail investments and port improvements. Reserves are probably more extensive than currently listed. A lack of organized mining unions generally means a more stable labor force. Mining technology is advanced.

CHINA

During 1979, China exported about 7 mst of its 700 million ton production. Much of this coal is bituminous and of uncertain quality. Japan received .3 mst of steam coal, .3 mst of metallurgical coal, and .4 mst of anthracite. Mining is predominantly underground, and mining technology is backward. Transportation technology is especially deficient.

Because of the extensiveness of the Chinese reserve and its proximity, Japanese investors have loaned $1.5 billion to China to help develop the infrastructure necessary for exports to Japan. Even so, it is estimated by ICETF that this will have a slow effect, possibly coming to fruition in the 1990s.

In addition to Japan, China can expect to capture an increasing share of other Pacific Rim nations (notably Hong Kong and Taiwan) because of its geographic location.

U.S. Coal Sources

Not only must NGP coal compete with other international coals for the market, it also must compete with other western domestic coals. The chief relevant characteristics of importance in determining this decision process are listed in Table 10.11.

Table 10.11
U.S. Western Coal Characteristics to Japan

Region	Rank	Btu/lb	%S	Port	Rail Miles	Maritime Dis-tance+	1980 $/ton Mine FOB/ton price
NGP (Wy)	Sub	8,100	.5	Kalama	1050	4,500	7.00
NGP (Mt_1)	Sub	8,600	.7	Kalama	1150	4,500	10.00
NGP (Mt_2)	Sub	9,300	.4	Kalama	1150	4,500	12.00
Washington	Sub	8,100	.9	Kalama	140	4,500	25.00
Green River	Sub	9,300	.6	Portland	750	4,750	17.00
Utah	Bit	11,500	.6	L.A.	710	4,750	25.00
N. Mex.	Sub	9,000	.7	L.A.	680	4,850	16.00
Colorado	Sub	10,700	.5	Stockton	1150	4,750	18.00
Arizona	Sub	10,000	.6	L.A.,Long Beach	630	4,850	20.00

Source: Monell, L.F. 1962. Factors Affecting International Coal Trade. Morgantown, W.V.: West Virginia Univ., p. 8; Lee & Harr. 1981. Northern Great Plains Coal Market Model, W.P. IX; ICETF. 1981. Interim Report of the Interagency Coal Export Task Force, Table 5-5.
+Nautical miles.

While NGP coals are least-cost FOB per ton, the inland transport distance to port is not advantageous. This distance is 1050 to 1150 miles for Montana and Wyoming NGP coals, respectively. However, the apparent advantage for inland transportation distance for Washington coals is misleading since these reserves are quite small and probably could not sustain long-term Pacific Rim contracts. Heat contents for several other Western coals are more advantageous, notably Utah, Green River, and Colorado coals. Coals with sulfur contents of .7% or above have a disadvantage because of the need for more extensive FGD equipment for their burning (Coal Week, 1981).

Cost Minimization and the Pacific Rim Market

According to microeconomic theory, the consumers of coal in the Pacific Rim market will be attempting to maximize their utility from the purchase of various coals that will satisfy their energy requirements at least cost (Griffin and Steele, 1980). In an absolute sense Pacific Rim customers would derive greatest utility by purchasing coal that costs least in terms of Btu heat content--the desired commodity. The Japanese exodus from the oil market has been driven by increases in the price of petroleum relative to those of coal. According to a strategy of cost minimization, the coal supply source to the Pacific Rim that could elicit the lowest delivered price per 10^6 Btus would take 100% of the demand. Table 10.12 depicts delivered costs of a ton of coal by source, both nationally and internationally. Table 10.13 breaks this information down into delivered cost per 10^6Btus.

Table 10.12
Coal Costs Delivered to Japan by Source (1980 $/ton)

	FOB Min. $/Ton	Domestic Trans.	Ocean Trans. +	Delivered Price$/ton
Australia	23	5	10	38
S. Africa	20	7	14	41
Canada	20	14	10	44
China	15	20	5	40
NGP (MT)	10	22	10	42
NGP (WY)	7	24	10	41
Washington	25	4	10	39
Green River	17	16	10	43
Utah	25	15	11	51
N. Mexico	16	15	11	42
Colorado	18	24	11	53
Arizona	20	14	11	45

Source: Wilson, C.L. 1981. Coal: Bridge to the Future. Cambridge, MA. Ballinger, p. 126 and ICETF. 1981. Interim Report of the Interagency Coal Export Task Force, Table 5-5.
+Includes loading and unloading costs.

Note that Wyoming-based NGP coals would not be as competitive because of the difference in average heat content of the two fuels.

Table 10.13
Delivered Costs to Japan (1980 $\$/10^6$Btu)

	Btu/lb	$\$/10^6$Btu
Australia	11,500	1.65
S. Africa	11,000	1.86
Canada	9,000	2.44
China	10,000	2.00
NGP (MT_1)	8,600	2.44
NGP (MT_2)	9,300	2.20
NGP (WY)	8,100	2.53
Washington	8,100	2.41
Green River	9,300	2.31
Utah	11,500	2.22
N. Mexico	9,000	2.33
Colorado	10,700	2.48
Arizona	9,500	2.37

Source: Wilson, C.L. 1981. Coal: Bridge to the Future. Cambridge, MA. Ballinger, p. 126 and ICETF. 1981. Interim Report of the Interagency Coal Export Task Force, Table 5-5. Lee, M., and Harr, B. 1981. Northern Great Plains Coal Market Model, p. 5, WESPO, 1982, Denver, CO.

Thus, on a purely cost-minimizing basis, Japan would choose Australian coal. If there were a need for diversification of supply for security and competition, South Africa and China would be next in line. The U.S. would be a fourth choice. The three least-cost coals in the U.S. in descending order are Utah, Montana and Wyoming coals.

Supply Interruption Risk, Diversification, and Competition

The Japanese have announced their intention to diversify their supply sources so as to reduce the risk and damage associated with import coal supply interruptions (Tajiri, 1981). This response indicates that the Pacific Rim is experiencing a market failure of the externality type. The true social cost of nonsecure energy supplies are not reflected in their import price. Since domestic Japanese energy sources only account for 10% of total Japanese need for 1990, any interruption of a single large supply will lead to considerable macroeconomic damage.

A strategy of diversification of supply from not only various fuels but from various supply sources of each fuel would reduce the severity of economic damage from interruption. The necessity for such a policy was confirmed in 1980 when Australian mine worker strikes and South African inability to make up the shortage created by the strike disrupted Japan's coal supply; 900,000 tons of Utah and Colorado coals were purchased on the spot market at high cost.

Japanese officials point out that supply diversification would promote competition between the various sources to assure lowest delivered price of coal from each. It is difficult to estimate the optimal mix and number of sources for the Japanese market to balance least-cost and security of supply. It is possible to consider the various coal sources in terms of their sociopolitical environments and labor-production situtations to rank them from least secure to most reliable. Table 10.14 ranks these coal supplies on a subjective basis.

Table 10.14
Rank of Coal Supply Security by Source+

Source	Comments
South Africa	Racial problems; restless political situation.
Australia	Labor disputes make interruptions likely.
China	Poor transportation network; a security system of exports to the east will be a decade in developing.
U.S. (eastern, underground)	United Mine Workers strikes may cause problems.
U.S. (western, underground)	Labor-intensive methods are more subject to disruption.
U.S. (western, strip-mine)	Labor detensive; extensive elastic supply base.
Canada (western, strip-mine)	Stable work force; no organized union activity; past indicates political neutrality and stability.

+From least to most secure.

From this rather crude analysis, it seems that an optimal Pacific Rim purchase policy might be to purchase roughly 60% of their supply from relatively uncertain but least-cost sources as Australia and South Africa, with the remainder purchased from more expensive but also more dependable sources such as China, the United States, and Canada. Since Chinese export potential probably will not be reached before the mid-1990s, it is probable that Australian and U.S. western coal will be purchased over this period. However, it is doubtful if substantial U.S. coal purchases will occur by 1985 (ICETF, 1981). Japanese officials have stated that U.S. coal prices are on the upper boundary of what they are willing to pay, even for secure sources. Thus, the criteria that will determine the extent and type of U.S. coal purchased will be governed by cost of the coal according to heat content and also by other physical characteristics that might influence the coal's use in Pacific Rim utility and industrial boilers and kilns. Perhaps 10% to 15% of Eastern coal imports may be met by the very secure Canadian exports (Wilson ed., 1981) but not until later, since Canada does not seem to be moving as quickly as the U.S. on the necessary port improvements.

U.S. Share of the Market

The U.S. share of the Pacific Rim market is contingent on several factors. Obvious considerations include the delivered price of coal per ton to the Orient and its heat value. However, other less apparent concerns include the development of nuclear capacity in the Eastern energy mix and the development of competitive Chinese and Canadian steam coals.

In addition, the ultimate amount of U.S. coal demanded by the Eastern market is ultimately tied to the overall world economic growth (Wilson ed., 1981), especially growth in demand for electricity. Decisions on the fuel choice for new utility boilers in the East will be important. Competing fuel choices include nuclear and liquid natural gas (LNG) as utility fuels. These fuels also offer a particularly attractive feature because of their low emission levels, a matter of concern for environmentally sensitive areas.

China has lacked the capability to export to the East, although Japan is investing large sums in China and also in the western U.S.S.R. in order to improve the mining and transportation infrastructure. It is estimated by ICETF that these exports will not be significant before the mid-1990s. Little is known about the prospects for Indonesian coal exports. India, although shown as a major world coal producer, is unable to export more than just a few million tons because of heavy domestic energy resource demand and lack of necessary port and transportation facilities.

As seen in Table 10.12, the United States can expect to deliver coal to Japan at a cost disadvantage of at least $6 per ton (compared to Australia) and a cost disadvantage of at least $1 per ton compared to South African coals. These rates set the U.S. at the economic boundary of the 10% to 15% premium that Japanese buyers are willing to pay for diversification and security purposes (ICETF, 1981). The U.S. will be, at best, third on the list of steam coal exporters in terms of the delivered cost of coal.

Other questions in determining the demand for U.S. coal in the East include the extent to which other potentially lower cost producers, such as China and the U.S.S.R., will attempt to expand production and whether Eastern coal buyers will seek to diversify supply sources, regardless of costs, to avoid a weighted dependence on Australian and South African coals.

ICETF estimates based on this data that the 1985 U.S. market share would be very close to zero but would reach nearly 15% by the year 2000. ICETF admits that this casual prediction conflicts with announced Japanese intentions, which state their desire that no more than 25% of steam coal imports come from any one country (ICETF, 1981). Thus the DOE Task Force forecasts that approximately 18% of Japanese import demands would be met by the United States. WOLCO predictions of the U.S. market share is strongly sensitive to world coal demand and hence to world economic growth. Generally, a faster growing world coal demand will favor the percent share of the potential U.S. market. Slower growth will tend to benefit the marginal competitors, especially those geographically more proximate to the Orient. Table 10.15 lists the predicted U.S. share of the Pacific Rim as shown by the ICETF and WOLCO studies. Note that the WOLCO predictions are only for the year 2000. The U.S. share is assumed to be negligible in 1985 but to advance rapidly after this point.

Table 10.15
United States Market Share of Steam Coal Trade in the Pacific Rim
(Percent of Total)

Importer	1985	1990	2000
Japan	10	15	25
S. Korea	0	0	0
Taiwan	~ 5	20	20
Hong Kong	~ 5	20	25

Source: ICETF 1981. Interim Report of the Interagency Coal Export Task Force. DOE FE0012. Washington, D.C., Table 6-7.

The figures in Table 10.15 suggest that the U.S. market share increases as world steam coal demand itself increases (ICETF, 1981). In a similar estimate (Table 10.16), the WOLCO teams estimated that in the year 2000 the U.S. and Australia would receive roughly a third each of the Eastern market, with Canada and the People's Republic of China receiving 10% each and the remaining percentage scattered. The total potential U.S. share of the Pacific Rim market is depicted in Table 10.16.

Table 10.16
Potential U.S. Steam Coal Market Share

Year	Percentage	MTY
	ICETF	
1985	~ 0	0
1990	17	15
2000	25	52
	WOLCO	
2000 High	27	130
2000 Low	28	73

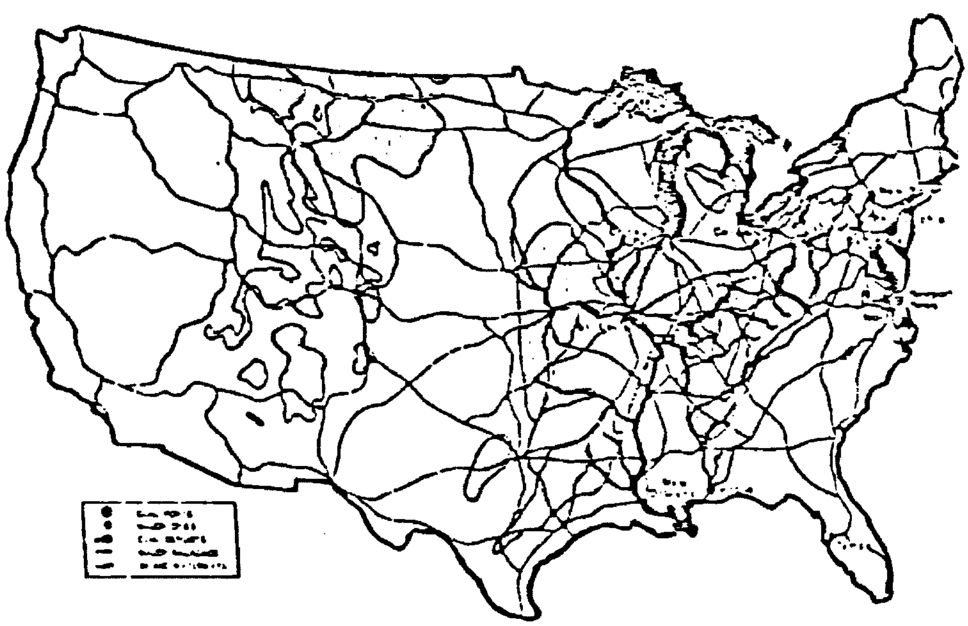
Source: ICETF 1981. Interim Report of the Interagency Coal Export Task Force. DOE FE-0012. Washington, D.C., Table 6-8. and Wilson, C.L. 1980. Coal Bridge to the Future. Cambridge, Mass.: Ballinger., p. 113.

Even the lower demand case of the WOLCO prediction is about 30% more than that forecasted by ICETF. Demand for U.S. export steam coal rises slowly in the 1980s and then rapidly in the 1990s to the year 2000. Based on consensus, by the year 2000 the U.S. will supply coal to about 25% of the Pacific Rim market--an amount placed conservatively at about 50 million short tpy.

The greatest constraint on the future demand for U.S. Western coal is the availability of rail transportation routes and port facilities on the Pacific coast for export. These ports also need to be able to handle the quantities of coal necessary (OTA, 1981). Figure 10.2 presents the major U.S. coal deposits over land by Class One railroads (those with an annual operating revenue of over $50 million in 1970). Figure 10.3 shows proposed coal export terminals on the west coast. Of the final delivered cost of coal delivered to Japan, inland transportation is typically over 30% of the total cost. It is also a relatively unreducible expense (Harr and Lee, 1981). These unit trains are designed to haul a single commodity moving continuously between mine and consumer at 800 miles per day instead of the 60 miles per day generally expected with general freight service (OTA, 1981). The available unit train routes in Figure 10.2 are important because they determine the miles to port. If no unit train service is available, the economics of export to the Pacific Rim may be constrained by the cost of laying new rail track--up to $1 million per mile! This is precisely the case with the Arizona Black Mesa coals, which have no unit train service available within a hundred miles. This will probably reduce the coal's ability to be shipped economically to the ports of Long Beach or Los Angeles. The costs of moving coal to port in the West are higher than those expected in the eastern U.S. for a given distance because of the need to move up and over the Rocky Mountains.

Figure 10.2

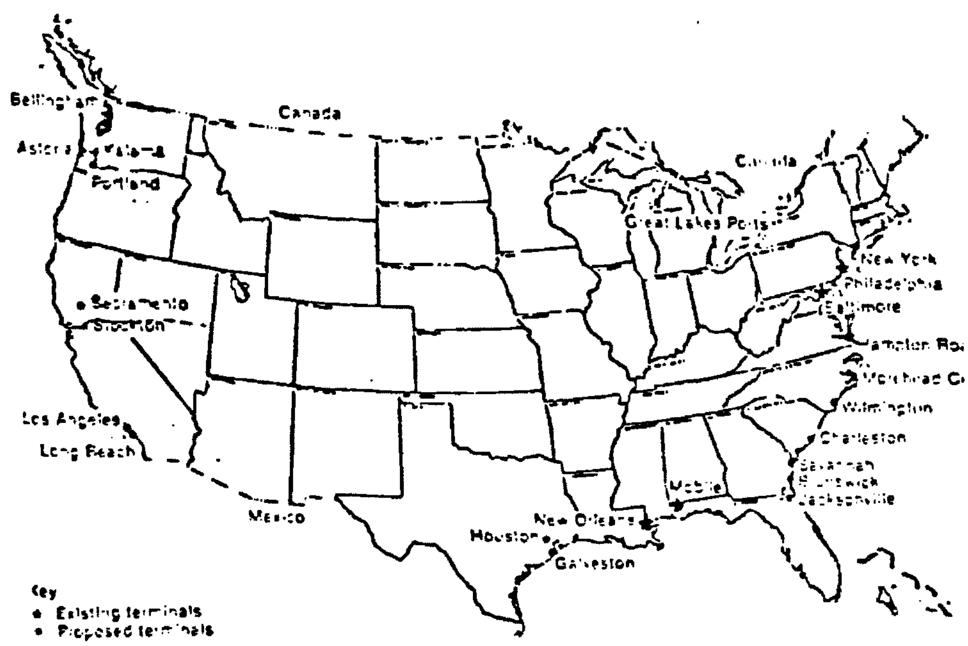
MAJOR U.S. COAL DEPOSITS AND RAILROADS



Source: Office of Technology Assessment, 1981. Coal Exports and Port Development, Washington D.C.

Figure 10.3

EXISTING AND PROPOSED COAL PIERS IN THE U. S.



Source: Office of Technology Assessment, 1981. Coal Exports and Port Development, Washington D.C.

Currently there is no west coast port facility that is able to handle the quantities of coal that might be expected with a major export market to the East. Limited quantities of coal have been shipped to Japan via California ports in experimental runs. Ports under construction in California include Los Angeles, Long Beach, Sacramento, and Stockton.

The Port of Los Angeles has a capability of handling up to 1.5 mty of coal for export. It has a 51-foot channel depth for handling larger draft vessels and a coal storage unit capable of holding 100,000 tons. Long Beach has a similar capacity and could move up to 2.0 mty at present. Both ports are in the process of upgrading their existing terminals to a capacity of 20 and 30 mty by 1985 for Los Angeles and Long Beach respectively.

The ports of Sacramento and Stockton, California, are being carefully considered, since they are the closest ports to several Rocky Mountain coal deposits in terms of railroad mileage. Sacramento has large areas available for open storage of coal but suffers from having a limited 30-foot-deep approach channel. Stockton, located 75 miles east of San Francisco, has a slightly better channel (35 feet deep) and the land required to store coal. The Stockton port already has rail access, a 40-car per 8-hour shift dump facility, and the potential for a circular unit train track.

Ports in the Pacific Northwest are advancing more rapidly than are their southern counterparts in developing coal export port capability. Plans are furthest advanced in Kalama, Washington, and Portland, Oregon. Port officials in Portland are currently taking bids for work on a multiphased export terminal with a final design capacity of 10 to 12 mty. The $30 million first stage of the project is slated to begin in late 1983. The storage site is to be located on the Willamette River 100 miles upstream from the Pacific Ocean on a 40-foot channel rail service to Portland. The terminal will be connected to service from the three rail carriers that figure prominantly in western coal exports--Union Pacific, Southern Pacific, and Burlington Northern.

A Honolulu-based firm, Pacific Resources, Inc., is developing a 15 mty coal port on a 200-acre site on the Columbia River near Kalama, Washington (OTA, 1981). The port will initially have smaller capability but will be designed to handle unit trains on two circular rail tracks; from these the coal is transferred into hoppers and then loaded onto ships. The project is slated to be completed by 1985, and to cost an estimated $60 million.

Two other proposed ports in the area are Astoria, Oregon, and Bellingham, Washington. A $50 million, 200-acre site on the Skipanon River is being evluated by Astoria port officials in terms of a contemplated 5 mty export capacity. However, expensive upgrading of Burlington Northern track linkage to the port is considered crucial. Bellingham, Washington, 100 miles north of Seattle, is located on a deep draft harbor that would accommodate 250,000-pound vessels--larger than any other west coast port. However, there is community opposition to a proposal for a coal export terminal on this site, and final plans are indefinite.

Once work is begun on improving or constructing a port facility, it is typically four years or more until completion. Thus, the only ports on the west coast available for coal export before 1985 would be the ports of Long Beach and Los Angeles. This would tend to exaggerate the relative competitive advantage of coals from Arizona, New Mexico, Utah, and Southwestern Wyoming during the initial phase of Far Eastern imports of U.S. coals--to the detriment of exports from the NGP region. The earliest time the NGP coals could economically be considered for export would be with the availability of the Kalama and Portland facilities in 1985.

Table 10.17 depicts the approximate implementation schedules of new coal export terminals from the U.S. western coast.

Table 10.17
Summary of West Coast Port Improvement Schedules

```
                                   T I M E
                              Date Construction Begins
Port           1981   1982   1983   1984   1985   1986   1987   1988

Long Beach     |-----------------|
Portland       |------------------------------|
Kalama           |-----------------------------|
Sacramento             |----------------------------------------------
Stockton                      |---------------------------------------
Los Angeles                   |---------------------------------------
Bellingham                 |------------------------------------------
```

Source: Office of Technology Assessment. 1981. Coal exports and Port Development Washington, D.C.

Influence of Physical Coal Characteristics

Other physical and chemical characteristics of coal can influence the choice of coal by foreign buyers. Some of these characteristics also relate to existing utility and industrial technology in the Far East. Because boilers and process heaters must often be designed for a particular type of coal, the coal used in the past is significant. This will make the choice of a U.S. coal supplier more predictable when viewed in terms of the cost minimization strategy presented in Tables 10.12, 10.13, and 10.14. It is useful to inspect physical, chemical, and combustive characteristics of Australian coals that find the widest applications in the Pacific Rim. These coals from Newcastle or Port Kembla, Australia, have a heat content of 11,500 to 12,000 Btu/lb, 1.0% sulfur or less, an ash content of 15%, and a moisture content of about 10% (Coal Week, 1981). Thus, U.S. coals with similar characteristics will likely be favored by Far Eastern buyers. The sulfur content of Australian coals must not be exceeded if environmental emissions are to be controlled. The ash content of coal also represents another pollution control problem for particulate control. The ash content is important, as it relates to heat content, which determines the rate at which a coal must be burned by weight to achieve a given heating performance. This factor affects the fouling characteristics of the coal in combustion; the lower the Btu value of the coal and the greater the ash content, the greater the likelihood it will require slag removal, soot blowers, etc. (Fortis, 1981). The moisture content also figures importantly in the fouling characteristics of a particular coal--the lower the better. Since we can assume that Far Eastern boilers and process heaters have been designed to burn coal with physical characteristics listed previously, it is useful to examine the same characteristics of the various available western coals being studied for "fit" to the Australian type. Table 10.18 lists these characteristics for the eight coals studies in the western U.S.

Table 10.18
Comparative Western U.S. Coal Characteristics

Region	Rank	Btu/lb	%S	% Ash	Moisture (%)
Australia	Bit	11,500	1.0	15	10
NGP (WY)	Sub	8,200	.5	8	26
NGP (MT)	Sub	8,700	.5	5	25
Washington	Sub	8,000	1.2	12	25
Green River	Sub	9,300	.5	5	21
Utah	Bit	11,500	.6 - 1.0	10	10
New Mexico	Sub	9,000	.7	20	13
Colorado	Sub	11,500	1.0	9	12
Arizona	Sub	10,000	.6	10-20	10

Source: Smith, L.C. 1981. "Utah Coal Mining and Marketing." 2nd U.S. - Japan Coal Conference. Lake Tahoe, Nevada; Lee and Harr. 1981. Northern Great Plains Coal Market Model, p. 5; Mining Information Services. 1980. 1980 Keystone Coal Industry Manual. New York: McGraw-Hill; Matson, R.E. 1969. "Montana's Shippable Coal Reserves," Proceedings of Montana Coal Symposium, Billings, MT.

Utah and Colorado coals are most similar to the Australian coals now used in the Orient. It is believed that these two coals will be favored for more than the delivered price of their heat content (Smith, 1981; McKeever, 1981), since their similarity to Australian coal augments the advantage Utah and Colorado coals would command delivered to the Far East. It would be a simple matter to convert Pacific Rim utilities, boilers, and process heaters from Australian to Utah or Colorado coals, a factor that would be important in the Japanese effort to achieve security through diversification. For such a plan to succeed, the "secure" coals must be usable in facilities that normally use "insecure" coal. For example, the high moisture content of NGP coals (more than double that of Australian coals) would make their use in many boilers and kilns impossible without considerable retrofit and combustion modifications. Reports indicate that no existing Pacific Rim utility boiler can use NGP coals because of their low Btu content and high moisture content, which promotes fouling (Fortis, 1981). This would seem to defer any decision to use the NGP coals until the construction of a utility boiler designed for their use. Just as NGP coals have taken longer than other coals to be developed in the U.S., they may also be exported at a later period than the other coals. It is possible that the difficulty in substituting NGP coal in existing Pacific Rim coal-burning facilities may delay import contracts for NGP coal until the 1990s, when utility boilers may be built that are designed to burn this low Btu, high moisture fuel. These characteristics lessen NGP's competitiveness for export in the near future and single out Utah bituminous coals as the logical first choice, both in terms of cost-minimization criteria and flexibility for use in existing coal facilities.

Recent Developments

CURRENT STEAM COAL EXPORTS

The history of Japanese coal imports from the U.S. was .4 mst in 1979, 1.0 mst in 1980, 3.9 mst in 1981 and 3.4 mst in 1982. Most of this coal was from the Price, Utah area with the balance from the Uinta, Colorado region and all was shipped from California ports in Los Angeles and Long Beach. The lower export figure in the last year reflects the soft condition of current international steam coal market. The Japan Tariff Association has reported the average delivered price of its imported coals. This is shown in Table 10.19.

Table 10.19
Average Cost-Insurance-Freight Price Per Ton to Japan

Source	$1980/ton	$\$10^6$ Btus
Australia	$49	$1.95
Canada	$48	$1.91
South Africa	$36	$1.43
U.S., Utah	$60	$2.38

Source: Japan Tariff Association, "Japan Exports and Imports," December, 1980.

This recent history is strictly in accordance with the prior projections which predicted these coals to be the first choice of the Japanese due to their physical characteristics and the importance of substitutability in the supply diversication strategy.

RAIL DEREGULATION

One of the main determinations from the export study has been the sensitivity to the assumed inland transportation rates. The Staggers

Rail Act of 1980 has effectively deregulated the railroads which could have a substantial effect on the cost of U.S. coal to the Orient. The act is intended to increase the domestic economic viability of the railroad system.

On the positive side the act allows railroads to enter into long term negotiated contracts for service which is a measure of security that most Far East buyers will want to insure. Unfortunately, the Japanese are fearful of entering such long term contracts because of the high price of Western coal and the various economic uncertainties that exist in the international energy market (Wespo, 1982). This is particularly bad for coal investment as the favorable economics are not usually generated until after a long project life.

However, the act also has provision for rate increases so that railroads will derive "adequate revenue" from their operations. This probably will mean large increases in rail rates in the late 1980s (EIA, 1983). Analysts believe that the real rate of rail rate escalation may be between 3 and 6% over the next ten years. This would have the effect of greatly increasing the cost of export coal to the Orient over the long term. This coupled with the Japanese proclamation that "U.S. coal lies on the outside boundary of price acceptability" may mean that the U.S. will steadily be squeezed out of this market over the next twenty years by lower cost competitors such as China and Canada.

On the other hand the provisions for long term negotiated contracts for rail transport could mean lower rates for unit train service. The analysis here and in the DOE analysis assumes a variable cost of two cents per ton mile for transport and a one dollar fixed cost (1980 dollars). Note that the variable cost component is much higher than the 1.1 cent variable cost in the NGP utility coal market model. Thus there is some promise that lower rates might be negotiated with rail carriers to promote the export trade and enhance the competitiveness of U.S. coal in the Far East market.

CURRENT PACIFIC RIM EXPORT PROJECTIONS

In March, 1982 the Energy Information Administration released a report containing recent projections of U.S. coal exports (EIA-0317). This report generally supports the previous analysis, predicting steam coal exports to Asia in 1985 totalling about 7 million tons, increasing to 9 million by 1990 and remaining flat thereafter. This indicates DOE's growing pessimism of an expanding long term market and mainly as a reflection of the probable increase in rail rates. However, the northern coal centers were included in the report which estimated 1 million tons exported from the ports in the Northwest in 1985 and 2 mst from 1990 to 2000.

Another recent effort at stimulating the world coal trade situation, DOE's International Coal Market Model agrees with this assessment (EIA, 1982). It forecasts a share of the Far East Market reaching a peak of 4.1 mst in 1985 and then trending downward with increased competition for secure markets to 3.4 mst in 1990 and only .6 mst by 2000. This conclusion is in considerable conflict with the estimates rendered by WOLCO (1980) and ICETF (1981) where the U.S. western coal market to the East was forecasted to increase. However, the more recent study must be given serious consideration as it is based on a mathematic simulation and the ICETF and WOLCO results were from more subjective Delphi approaches. If such were true, it would have serious consequences for any potential NGP export market. Export development would likely never occur given such a scenario.

The most recent report by the General Accounting Office (1983) has verified this finding in terms of market behavior. The two year study found that the poor comeptitiveness of U.S. export coal is likely to continue since transportation costs are high. This was viewed as the major determinant of the export market share for each country. It was concluded that exports would continue to be less than 15% of total coal production and that the competition in the world coal market is apt to intensify. China may be a major competitor or the Pacific Rim market by the turn of the century since its proximity to Japan could result in low delivered prices.

THE WORLD ECONOMY

Over the last two years the world economic picture has not been as advantageous as that assumed in the ICETF analysis. As a result the world steam coal market has been soft. The magnitude of world economic recovery will have a strong effect on the demand in the Far East for coal. A stymied recovery would be a setback to the possibility of the U.S. obtaining any share of this market since all coal could be supplied with existing contracts with cheaper sources. The world oil prices have stabilized and even declined in real terms due to recession and surplus. This has reduced the economic incentive for conversions from oil fired equipment to coal and with it potential demand for more sources of international steam coal.

PORT DEVELOPMENT

Currently the U.S. is at best a marginal supplier to the Far East market. Ocean transport costs typically from 25% or more of the cost of a ton delivered to the Pacific Rim countries. Thus significant economies of scale are possible in this transport if larger vessels are used for the cargo. Costs saved include capital cost component inherent in each ton moved and the fuel costs for the voyage.

However, these larger vessels (typically in the 100,000 Dead Weight Tons (DWT) class and over) require a greater draft in the ports that service them. This means that the 60 foot depth of the Long Beach port can service a considerably larger vessel than the Los Angeles port of 51 feet. Currently there are plans to deepen most of the western ports to acquire this economy although the federal government will require tariffs to pay for the expense. These tariffs will then reduce a large part of the savings so that the net reduction in ocean transport may only be a couple of dollars per ton. This will not be particularly competitive because the other major exporters are doing the same and in most countries the improvements are government subsidized. However, to not undertake these improvements would be detrimental to the already poor U.S. economic situation for coal exports.

Currently there still are no ports in the Northwest other than Seattle and Portland that are capable of handling the large amounts of coal necessary for a sizeable export market to the East. Several are still under development but are not likely to be available for at least another two years. Also, the port facility proposed for San Francisco has been cancelled due to lack of long term contracts with Japanese buyers. It still seems likely that the earliest date of exports of coal to the East from NGP fields will not come until after 1985.

Physically, there are few constraints on the export of NGP coal. This is due to the extremely vast nature of the Great plains reserves (fully 40% of the U.S. surface reserves) and the technological advancement of current mining methods (OTA, 1981). Also, rail capacities in the area appear to be sufficient to handle large export tonnages (WESPO, 1982). However, the lack of suitable ports will insure that Powder River coals are excluded from the first round of exports.

The economic constraints on export development are more intractable. Specifically, the high cost of rail transport is a decidedly negative factor in the export potential of the coal. Short term non-unit train rates will not allow the NGP coals to compete for the Pacific Rim market since they are nearly double that of unit train costs of shipment and the appropriate ports are more than a thousand miles from the mines. This more than destroys the competitive advantage of low minemouth costs that the NGP coals enjoy in realtion to other western sources. The only hope that NGP coals have in the export market is to enter into a large long term contract with the East so that a lower cost of inland transport may result. If this was done, NGP coals would be lower than any others from the west on a heat basis and would even approach that of the South African coals. However, this is a big if. The rail rate deregulation from the Stagger's Act of 1980 is apt to result in higher rail costs rather than lower costs over the long term. This would serve as a negative influence on the willingness of both the Eastern buyers and the rail carriers to enter into long term contracts.

Even worse is the fact that a bias will remain in Japanese purchasers towards coals similar in physical characteristics to that of the Australian and South African coals they use. This will mean a continued purchase of the Utah and Colorado coals. Again, the only way the low Btu, high moisture content NGP coals might be used is if long term contracts are entered so that boilers and kilns might be designed to use these sub-bituminous coals. This in turn will strongly depend on a favorable world economy. Furthermore, this is not in line with the Japanese risk aversion strategy which places important value on the ability of substituting different coals in the same facility.

NGP Export Potential

Based on these gloomy factors, it is predicted that there will be no evidence of significant NGP export contracts to the East before 1990. After that point, the emergence of an export market for NGP coals will depend on an expanding world economy and negotiation for low long term rail rates with insurance of a secure uninterrupted supply. Even so, recent analytic projections of the coal exported to the Orient have shown expectations of a relatively flat market after 1985 with a U.S. export of only 7 million tons as late as 1995 (EIA, 1982). However, other estimates have given this amount to be greater than 50 million tons by the turn of the century (ICETF, 1981). WOLCO (1980) has forecasted a 70 million ton demand from the U.S. in its low demand case for 2000. A high demand case from the same study estimated a 130 mst export market for the U.S. to the Orient by that time. Clearly, in light of recent developments, this figure seems dubious. In summary there will be great uncertainty as to the actual U.S. export to the Pacific Rim over the next two decades.

On the conservative assumption that the NGP coals might capture 10-15% of this emerging market, final demand could range from a .7 to 10 million ton export market by 2000. The greatest share of the contracts will continue to be with the substitutable and low cost Utah and Colorado coals purchased on short term agreements. Of course, with lower rail rates and long term contracts, then a competitive economic advantage to NGP coals might result in a capture of a market share twice the anticipated size. In any case, the export market for NGP coal is exceedingly uncertain and could range from almost nothing to an optimistic market of 10 million tons by the turn of the century.

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CHAPTER ELEVEN

QUALITATIVE CONCERNS OF INDUSTRIAL AND EXPORT COAL DEVELOPMENT

Introduction

This section will very briefly outline various qualitative concerns that exist with respect to industrial and export coal use. In general the objections to export of Northern Great Plains coal are considerably fewer than those associated with industrial use. This is because most of the environmental deterioration resulting from coal's combustion is displaced to another location. First, concerns associated with these uses are listed and subsequently discussed:

Industrial Concerns	Export Coal Concerns
1. Air quality	1. Mining reclamation
2. Acid precipitation	2. Hydrological effects
3. Social impacts	3. Social impacts
4. Mining reclamation	4. Ecosystem disruption
5. Hydrological effects	5. CO_2 buildup
6. CO_2 buildup	6. Rail traffic
7. Aesthetic values	
8. Ecological impacts	

Air Quality and Acid Precipitation

A plant the size of the one examined in the boiler feasibility study, with the best available pollution control technologies available, would release fifty tons of sulfur dioxide and 160 tons of particulate matter annually. Although small in relation to that of thermal electric power plants, these air pollutants could be considerable significance if industrial installations became widespread. In "industrial parks" with large combustors, this would compromise the air quality in areas downwind of such facilities (Renne & Elliott, 1976). This pollution could have effects on the health of the area's occupants, visibility of the air resource and productivity of surrounding agricultural, ranch and wilderness areas.

Acid precipitation is an associated result of the sulfur dioxide emissions. This fact has been disputed in recent times, however, high acidity of precipitation was first documented in Northern Europe and more recently in New England in the United States (Oden, 1976). Scientific study has shown that the most likely cause of the great increase in regional pH can be largely accounted for in terms of sulfuric and nitric acids derived from the release of sulfur and nitrogen oxides from fossil fuel combustion (Likens, et. al, 1976). More recent studies have shown that the effects of acid precipitation are not as confined to areas immediately surrounding the emissions as was once believed (Lewis and Grant, 1980). These investigators believe that emissions from the heavily industrialized mid-west can be detected in precipitation pH in remote sections of the Rocky Mountains. Although the causes of the change in precipitation chemistry is still debated, there is greater general agreement on its effects. These include stunting of agricultural and forestry productivity, the contamination of water resources and even the erosion of man-made structures. If we accept the hypothesis that this problem is fossil fuel induced, then the external costs of industrial coal combustion is a matter of concern.

Social Impacts

The social impacts of industrial coal use are difficult to quantify. In times of high unemployment there is certainly a positive impact of jobs creation from either industrial or export development (Stinson and Voelker, 1978). However, most the mining and technical jobs associated with industry tends to bring an outside labor force into the state (Polzin, 1974). In some cases, this large labor force is only present temporarily or seasonally. This has inordinate effects on local services which must be expanded in order to accommodate the increased population. This in turn contributes to the "boom and bust" cycle so common in the states of Montana and Wyoming. The attendant increases in crime, alcoholism and drug abuse in such circumstances are well documented (Montana Dept. of State Lands, 1979). Pressures on local services can lead to increases in local taxes to construct additional schools, housing, medical and other services. Such a "boom" can exact an undue burden on those who must remain there after the "bust" or at the end of the "seasonal campaign". An irreversible consequence of such development is the change in the community life that is almost certain to follow (Bureau of Reclamation and Applied Research, 1975).

Mining Reclamation and Hydrologic Effects

The issues of mining reclamation and hydrological effects have received close scrutiny in the past. About ninety percent of all coal mined in the Northern Great Plains is used to generate electricity. a In addition, a considerable increase in domestic coal based industry and export could open new mines and present the environmental problems associated with such activity.

With the reduction of the powers of the U.S. Office of Surface Mining, the federal enforcement of mine reclamation standards has become uncertain. However, all Northern Great Plains states have legislation requiring reclamation; although reclamation adds little to the minemouth price of coal (less than $.10/ton), there is a move to reduce these measures in order to increase mining industry productivity (Atwood, 1975). Although mining areas can be reclaimed in an aesthetic sense, so that the gashes of the strip mine process are not evident and erosion and surface water runoff is reduced, it is doubtful if the soil will be as productive as surrounding areas for many years.

The ground water problem is more intractable. In many areas of the Northern Great Plains, the coal seams are local groundwater aquifers. It may not be possible to reconstruct these in reclamation efforts (Shupe, 1977) and substitutes must be found. The limited water resource is vital to agricultural and ranching operations in the region. In many cases, the lands are taken out of production, especially where subirrigated alluvial valley floors are the mine-site. In this case the entire economic ranching unit can be jeopardized.

CO_2 Buildup

The carbon dioxide problem is difficult to estimate with accuracy. Briefly, with the exponentially increasing rate of fossil fuel combustion on earth, the observed levels of carbon dioxide are increasing at a similar rate. About one-half of the carbon dioxide produced by fossil fuel combustion accumulates in the atmosphere. Observed CO_2 concentrations have increased from 315 parts per million (ppm) in 1958 to 330 ppm by the mid seventies (Rotty and Weinberg, 1977).

This increase is in unprecidented for in 1900 the observed concentrations were on the order of 290 ppm. At the present rate, the observed concentrations seem to be even rising in the rate of increase. This increase could have grave consequencies for the global climate due to the "greenhouse effect". Atmospheric models suggest a global warming of about two degrees Kelvin if the CO_2 concentration were to rise to two to three times the pre-1900 level. This increase would be enough to change the world's climate in significant, but largely unknown ways. A shift to the use of coal in lieu of oil or natural gas releases more CO_2 per unit of heat produced. With the world recent rate of increase in fossil fuel use on the order of 4% per year these critical levels could be reached by the year 2030. Even projections of large reliance on nonfossil fuel energy after the turn of the century (Niehaus, 1980) shows concentrations of CO_2 reaching almost 500 ppm within fifty years.

Climatologists are unsure of the effects of such CO_2 levels, but agree that they would be disrputive to the distribution of rainfall and the possible position of sea level (Bach, 1979). Such effects would be largely irreversible at least in human timeframe and potentially devastating to international agriculture and coast-time economies. However, most studies have assumed that the rate of increase in fossil energy use must continue unabated and that this be the driving force of the problem. Recent data suggests that the exponential growth phase of global energy use has already come to an end (Hayes, 1980). More controversial investigations (Lovins, et. al., 1981 and Marchetti, et.

al., 1978) have forecast the decrease in future fossil fuel combustion on economic/thermodynamic and mathematic grounds. Regardless, others believe that coal use will dramatically increase in the next centry (Hafele, 1980). The CO_2 problem may exact an ultimate physical constraint on fossil fuel use and force an energy future based on nuclear or renewable energy resources.

Aesthetic Values

Aesthetic concerns of industrial coal use are probably the most subjective. Coal is a dirty fuel. Even with scrubbing and extensive pollution control some efficient remains and the cleaning residue must be disposed of safely. An industrial plant is an eyesore for many, a man-made creation of beauty for others. Certainly, lowered visibility in the air shed is not attractive and the siting of such plants could be restricted due to ambient standards and other control strategies. Will the coal industry spoil the skyline, a favorite trout stream or deface an area of collective personal significance? The question of a single industrial plant is perhaps more difficult to judge from an aesthetic point of view than is massive industrial devlopment. Who would desire to have Billings, Montana become the new Pittsburgh of the West? Perhaps only those who stood to gain financially yet not themselves living in the Billings environment. Unfortunately, with high unemployment in the West, many of the local populous may be willing to compromise their attractive environment rather than succumb to poverty. These questions are more easily raised than answered.

Ecological Impacts

Potential ecological impacts of increased mining and coal combustion include: loss of habitats or species of special interest, alterations in vegetation due to plant emissions or land disruption, and alteration in aquatic ecosystems due to changes in stream flows. Prediction of detailed impacts are strongly site specific and requires detailed regional and local data. The Northern Great Plains coal region is predominately a savannah or grassland. Typical wildlife in the are includes deer, antelope, grouse, hawks and other raptor species. They are present because of climatic and vegetative support systems. The most serious effects would be expected on the falcon, antelope, grouse and eagle populations (Montana Dept. of State Lands, 1979) where extensive mining or conversion takes place.

Export Concerns

Concerns for the export future of coal are similar to those previously discussed. The pollution, aesthetic and some social problems are displaced to another country. However, the gravity of the CO_2 problem, and the increase in environmental problems associated with increased coal mining are still apparent. Two other concerns that have been expressed are first those of nationalistic consideration and secondly the problem of increased rail transport bound for the West Coast through rural communities.

Should we sell coal to the Far East that we may need ourselves in time? This argument has relatively little merit. The reserves of the Northern Great Plains are vast indeed, possibly lasting centuries at current rates of energy use. Furthermore, this rate of increase seems to be declining, at least over the short term. The rail problem is more likely to be of concern. If unit trains haul coal on a regular basis to western ports, this will create daily traffic disruption and a considerable increase in the local noise level along the hauling routes. Perhaps some type of compensation for such communities from the railroads would be in order.

Summary

Several qualitative problems are associated with increased industrial and export use of Northern Great Plains Coal. Air quality in areas of industrial combustion may suffer, as might the aesthetic amenities of the region. Increased coal mining from both of these activities might have adverse impacts on limited ground water resources in the area, as well as the productivity of the affected soils. Social impacts of increased mining and industrialization in small communities in the eastern portions of the Montana and Wyoming may strain social services to the breaking and impair the existing quality of life. Export of the coal to the Far East may increase traffic disruption and noise in communities along the train routes. Finally, the problem of increased atmospheric concentrations on CO_2 may exact an ultimate limitation on the continued use of fossil fuels globally. Failure to heed this warning might have dramatic climatological, economic and social consequences for the world, which are difficult to predict at this time.

Finally, there is the question of whether we really need the additional cement, sugar and paper in order to lead more meaningful lives. In other words, must all demands be supplied?

If these "external costs" of using coal for industry and export were quantified, it would have a negative effect on the economics of coal use. This is especially true with respect to industrial coal use, since effluents would be released in the air and water systems. Willingness to pay assessment and compensatory surveys to quantify these aspects might be feasible to undertake, although they are beyond the bounds of this study. Certainly it would be difficult to estimate the externality of the CO_2 problem. I concluded, therefore, that the qualitative concerns of industrial coal use could be significant. It is certain that the above described problems would bias the case of industrial coal utilization in the West against further development.

The balance of trade advantage to the U.S. and the creation of new jobs puts the export market potential in a more favorable light. The question is whether the industrialized Far East is willing to take on the described externalities and still pay the high price of transporting a low Btu coal across the Western U.S. and the Pacific ocean.

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CHAPTER TWELVE

CONCLUSIONS

Industrial Coal

Industrial coal use in the NGP coal market will possibly double by the year 2000 from its current level of about 4 million tons. This new growth will take place primarily in cement and lime kiln conversions in the region and new industrial boilers in the paper and sugar industries. Most other small or process heat applications will not be able to use the coal based on technical constraints. Many of the larger boilers that will make up the new demand will be cogenerating facilities to take advantage of the favorable economies that are possible from this scheme.

The market size for industrial boilers is quite small because of the higher cost of transporting the coal and this could shrink as rail rates increase. As compared to natural gas, the prime alternate fuel competitor, the least cost size of the NGP market has a radius of only 130 miles. The price equilibrium boundaries were also determined for other competing Western coals although it was found that interfuel competition usually prevails before the boundaries were reached.

A formal uncertainty analysis was undertaken because of the very close annualized costs of coal and natural gas boilers. The analysis closely reproduced observed market behavior. Firms would most commonly choose natural gas for shorter time horizons than thirty years, or in a situation where uncertainty existed with respect to future economic conditions. The primary market for coal in industrial applications will be for large industrial boilers located near the mine, with cogeneration also on-site. Industrial parks might be formed where very high utilization rates could be obtained by two or more firms using the steam plant over three shifts per day. The other major application is in cement plants which have a very high energy use rate and where pollution controls are not required since the potential effluents make up part of the product. The economy of coal use in cement and lime kilns is readily demonstrated and the technology is proven. It may be the largest source of new industrial demand over the next twenty years.

Reasonable projections for the NGP are an industrial market of 6 million tons by 1990 and 10 million tons by 2000 corresponding to an annual growth rate of 4.8% over the 19 year period.. However, this will remain a relatively small proportion of the coal market through the period, only 5%. This rate is very close to the National Coal Association forecast for industrial coal growth over the same period. Their projection is based on favorable economic conditions that will encourage expansion in industry and is subject to any changes in this important factor. This analysis is specific only to the NGP coal market and may not be equally true in other regions in the U.S.

Export Coal

The export market is even more uncertain than the industrial demand. Currently there are no export sales of Northern Great Plains coal, nor is there likely to be any in the near future. The deterrent to current contracts is the lack of suitable port facilities for large export coal transport. However, this will change in the next few years as the ports of Kalama, Washington and Portland, Oregon are modified to take on this role.

The more significant long term disadvantage will probably be the cost of transport. NGP coals are more distant from port than other competing coals such as those from Utah where higher minemouth cost is more than offset by the lower total cost of inland transport. This transport differential could change if the Pacific Rim buyers were willing to enter into large tonnage long term contracts, where significant unit train economies could be realized. Thus far however, the buyers have not been willing to do this because of the high cost of Western coal and the uncertainties surrounding the prices of competing fuels in the world energy market. The other pessimistic factor in the export potential concerns the deregulation of U.S. rail rates by the Stagger's Act of 1980. While this will allow railraods to negotiate long term contracts, most analysts expect that it will mean large increases in the real cost of domestic rail transport over the next ten years -- perhaps from 3% - 7% annually! If this does occur and the Japanese are not willing to negotiate for long term, unit train contracts, then the outlook for an export market for Powder River coals is indeed bleak.

Still another negative influence to the prospect of export is the physical characteristics of the coal itself. The Northern Great Plains coals are low in sulfur, but also have a relatively low Btu and high moisture content. These characteristics limit its ready substitution in Far East facilities without boiler modification. Most of the coals used in the Pacific Rim are purchased from Australia and South Africa. These coals typically have a higher Btu content and a significantly lower moisture content. Since purchases from the U.S. are in the interest of diversification and security of supply, the substitutability of the coal becomes quite important to a purchase strategy. Given this consideration and the important factor of price, the analysis shows the best purchase choice will likely be the Utah coals. They are low in delivered price to Japan and have very similar physical characteristics to the coals currently in use in the Pacific Rim. This analytical result has been borne out by actual market behavior. So far, the only U.S. purchases for Pacific Rim export have been the high quality Utah and Colorado coals.

The final question is, will there be any export market for Northern Great Plains coal? The analysis shows that this will again depend primarily on world economic conditions. The forecasted export market for NGP coals ranges from .7 to 10 million tons by the year 2000 depending on several factors. The most important factor is the cost of transporting the coal to port. If there is to be an export market, rail subsidy or special business or governmental negotiations may be necessary. Another important condition is the future Far Eastern demand for steam coal. The NGP coals are relatively elastic in supply, whereas countries such as South Africa may be forced to limit their exports to the Far East in the future based on the prospect of reserve depletion. A favorable world economy and an expanding demand for coal would be the primary ingredient that could lead to a significant export market for Northern Great Plains coals.

APPENDIX

COMPUTER PROGRAM LISTING

LIST


```
100  REM ******************************
110  REM * INDUSTRIAL COAL MARKET MODEL*
120  REM ******************************
130  REM
140  REM
150  REM  PROGRAMMER: DANNY PARKER
160  REM
170  REM  DEPARTMENT OF ENVIRONMENTAL SCIENCE
180  REM  UNIVERSITY OF MONTANA
190  REM
200  REM
210  DIM N(30)
220 N = 30
230 HO = N
240  REM  N,HO= PROJECT TIME HORIZON
250  REM
260  REM
270  REM  DIMENSION VARIABLES
280  DIM AA(30)
290  DIM AB(30)
300  DIM PV(10)
310  DIM LE(10)
320  DIM P(30)
330  DIM E(10)
340  DIM K(10)
350  DIM V(30)
360  REM  N= TIME HORIZON
370 DR = .3
380  REM  DR= DEBT RATIO
390 PSR = .2
400  REM  PSR= PREFERRED STOCK RATIO
410 CSR = .5
420  REM  CSR= COMMON STOCK RATIO
430 DC = .095
440  REM  DC= DEBT COST
450 SC = .10
460  REM  SC= PREFERRED STOCK COST
470 CC = .135
480  REM  CC= COMMON STOCK COST
490 WCC = (DR + DC) + (PSR * SC) + (CSR * CC)
500  REM  WCC= WEIGHTED COST OF CAPITAL
510 IN = .06
520  REM  IN= ANN. INFLATION RATE
530 RCC = (1 + WCC) / (1 + IN)
540 RCC = RCC - 1
550  REM  RC= REAL COST OF CAPITAL
560 SFF = RCC / ((1 + RCC) ^ N - 1)
570  REM  SSF= SINKING FUND FACTOR
580 CRF = (RCC * (1 + RCC) ^ N) / ((1 + RCC) ^ N - 1)
590  REM  CRF= CAPITAL RECOVERY FACTOR
600  REM  KN= DEPRECIATION PERIOD
```

```
610 KN = N * .66667
620 CTF = (RCC * (1 + RCC) ^ KN) / ((1 + RCC) ^ KN - 1)
630 CB = CRF + SFF
640 DFR = (2 * (N * CRF - 1)) / (N * (N + 1) * RCC)
650  REM  DFR= SUM OF YEARS DIGETS DEPREC.
660 DC = (1 + DC) / (1 + IN) - 1
670  REM  IM= MARGINAL TAX RATE
680 IT = .525
690 TX = ((CB + AIR) - (1 / N))
700 TX = TX * (1 - (DR * DC / RCC)) * (ITR / (1 - ITR))
710  PRINT "LEVEL TX RATE= ";TX
720  REM  TX= FED AND STATE TAX
730 IM = .02
740  REM  IM= INSURANCE AND PROPERTY TAXES
750 AD = (2 * CB * (KN - (1 / CT))) / (KN * (KN + 1) * RCC)
760 LD = (AD - (1 / N)) * (1 - (IT * DR * DC) / RCC)
770 LD = LD * IT / (1 - IT)
780  PRINT LD
790 IC = .1
800 LC = (IC / (1 - IT))
810 LC = LC * ((CB / (1 + RCC)) - ((IT * DR * DC) / RCC) * ((CB /
     (1 + RCC)) - 1 / N))
820  PRINT "LC=";LC
830  PRINT "LD= ";LD
840 FCR = RCC + SFF + IM + TX - LD - LC
850  REM  FCR= FIXED CHARGE RATE
860  DIM T(20): DIM HC(20)
870  DIM DT(20): DIM FC(40)
880  DIM VC(40): DIM CP(20)
890  DIM PC(40)
900  DIM TC(20): DIM T1(20)
910  DIM DB(20): DIM DS(500)
920  DIM A(20): DIM E(20)
930  DIM D(500)
940  GOSUB 1640
950 K = 15.49 * 10 ^ 6
960  REM  K= CAPITAL COST AT RATED FIRING RATE
970 AK = 2.56 * 10 ^ 6
980 FR = 175
990 FR = FR * 10 ^ 6
1000  REM  FR= FIRING RATE
1010 OM = 2.04 * 10 ^ 6
1020 O2 = 1.15 * 10 ^ 6
1030 OM = OM * LE(3):O2 = O2 * LE(3)
1040 HRS = 8760
1050  REM  REM HRS= HOURS PER YEAR
1060  REM  OM= COST OF O&M FOR FR RATE
1070 CU = .60
1080  REM  CU= CAPACITY UTILIZATION PERCENT
1090 ANN = FCR
1100 K1 = ((FR / 175000000) ^ .75) * K
```

```
1110  REM  K1,K2= PLANT SCALE FACTORS
1120 K2 = ((FR / 175000000) ^ .65) * AK
1130 OM = (K1 / K) * OM
1140 O2 = (K2 / AK) * O2
1150 FC = (K1 * ANN) + OM
1160 F2 = (K2 * ANN) + O2
1170  REM  HC(I)= FUEL HEAT CONTENTS PER UNIT
1180 HC(1) = 8600
1190 HC(1) = HC(1) * .82
1200 HC(2) = 1000000
1210 HC(2) = HC(2) * .87
1220 CF(1) = 11 * LE(3)
1230  REM  CF(I)= COST PER TON
1240 CF(2) = 2.62 * LE(1)
1250 FC(1) = 2.75 * LE(2)
1260  REM  FC(I)= FIXED COST PER TON
1270 FC(2) = 0
1280 VC(1) = .043 * LE(2)
1290 VC(2) = 0
1300  REM  VC(I)= VARIABLE COST PER TON MILE
1310  REM
1320  REM  TOTAL COST OF PLANT OPERATION FOLLOWS
1330 T(1) = (FR * CU * HR) / (HC(1) * 2000)
1340 T(2) = (FR * CU * HR) / HC(2)
1350 A(1) = ((CF(1) + FC(1)) * T(1)) + FC
1360 A(2) = (CF(2) * T(2)) + F2
1370 B(1) = VC(1) * T(1)
1380  FOR X = 1 TO 100
1390 TC(1) = A(1) + B(1) * X
1400 TC(2) = A(2)
1410  PRINT TC(1),TC(2)
1420  IF TC(1) > TC(2) THEN 1450
1430  REM  TEST FOR COST EQUILIBRIUM
1440  NEXT X
1450  HOME : INVERSE
1460  PRINT "MARKET BOUNDARY SUMMARY"
1470  PRINT
1480  NORMAL
1490  PRINT "TONS PER YEAR- NGP= " INT (T(1))
1500  PRINT
1510  PRINT "MCF PER YEAR- NAT. GAS= ";T(2)
1520  PRINT
1530  PRINT "ANN.COAL CAP CST= $";K1 * ANN
1540  PRINT "ANN.ALT. CAP CST= $";K2 * ANN
1550  PRINT "ANN.COAL O&M CST+ $";FC - (K1 * ANN)
1560  PRINT "ANN.ALT. O&M CST= $";F2 - (K2 * ANN)
1570  PRINT "ANN COAL FUEL CST= $";TC(1) - FC
1580  PRINT "ANN ALT. FUEL CST= $";TC(2) - F2
1590  PRINT
1600  PRINT "MARKET BOUNDARY= ";X - 1" MILES"
```

```
1610  PRINT : PRINT "COAL PLANT COST AT BOUNDARY= "; INT (TC(1))
1620  PRINT : PRINT "N.GAS PLANT COST AT BOUNDARY= "; INT (TC(2)
 )
1630  END
1640  REM  LEVELIZED FUEL PRICE SUBROUTINE
1650 D = PCC
1660  REM  PRICE ESCALATION RATES, YEARS 1-10
1670 E(1) = .04
1680  REM  E(1)= FUEL PRICE
1690 E(2) = .03
1700  REM  E(2)= TRANSPORTATION COST
1710 E(3) = .01
1720  REM  E(3)= O&M COST
1730 K(1) = .02
1740  REM  PRICE ESCALATION RATES, YEARS 11-N
1750  REM  K(1)= FUEL PRICE
1760 K(2) = .02
1770  REM  K(2)= TRANSPORTATION COST
1780 K(3) = .01
1790  REM  K(3)= O&M COST
1800  REM
1810  REM  UNIFORM PRESENT WORTH-MODIFIED CALCULATION
1820  FOR I = 1 TO 4
1830 AA(I) = ((1 + D) / (1 + E(I))) - 1
1840 AB(I) = ((1 + D) / (1 + K(I))) - 1
1850  FOR N = 1 TO 10
1860 F(N) = 1 / ((1 + AA(I)) ^ N)
1870  NEXT N
1880  FOR N = 11 TO HO
1890 V(N) = 1 / ((1 + AB(I)) ^ N)
1900  NEXT N
1910  FOR N = 1 TO 10
1920 P = P + F(N)
1930  NEXT N
1940  FOR N = 11 TO HO
1950 V = V + V(N)
1960  NEXT N
1970 PV(I) = P + V
1980 P = 0:V = 0
1990 LE(I) = PV(I) * CRF
2000  PRINT LE(I)
2010  NEXT I
2020  RETURN
2030  END
```

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