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# THE UTILITY MARKET FOR COLORADO COAL: RECENT PAST AND IMPLICATIONS FOR THE FUTURE

By

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# ABSTRACT

The future marketability of Colorado coal deserves rigorous analysis due to recent declines of coal production in the state and sales to both Colorado and non-Colorado utilities. After a brief description of the Colorado coal reserve base, recent trends in the consumption and purchasing habits of Colorado and non-Colorado utilities that have purchased Colorado coal since 1978 are examined. The review of contract provisions and recent consumption behavior suggests that in both the Colorado and non-Colorado utility markets, Colorado producers are suffering from a decline in their competitive position relative to other producers in Wyoming and Appalachia who are capable of producing similar coals. Ways must be found to cut the cost of mining or transporting Colorado coal, if the industry is to return to a competitive position.

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# Chapter 1

## The Utility Market for Colorado Coal: An Introduction

The Colorado coal industry is mired in a deep recession. In 1983, coal production fell to 16.7 million tons, the second consecutive year of decline. Employment dropped to 2,600 from 3,200 in 1982 and 4,000 in 1981. Only 25 mines were active at the year's end compared to 35 in 1982 (CDM, 1983). Even more onerous, only one long term contract was signed during the year between a Colorado producer and utilities.

The coal industry in Colorado has always been cyclical. Figure 1.1 traces coal production from 1880 to 1983. From 1880, the industry grew steadily until 1910 when it peaked at 12.1 million tons. Between 1910 and 1930 the industry fluctuated around 10 million tons a year. Starting in 1930, the industry began a slow but steady decline, bottoming in 1958 at 3 million tons per year. In 1960 an upward trend began which continued until 1981 when the present slide began (CDM, 1983).

The cycles of coal production in Colorado suggest that the current downturn could have either of two characters. First, this downturn could reflect short term (less than five years) fluctuations due to factors which temporarily reduce the demand for electricity and therefore coal, for example, a general economic recession in the country. The fluctuating production between 1910 and 1916 is an historic example of this pattern.

The second type of decline is typified by the period between 1930 and 1958 when diesel fuel replaced coal as a fuel source for the railroads and natural gas became the primary fuel source for utilities. This type of decline is long term (greater than five years) and caused by changing conditions which either reduce the size of the market for Colorado coal or undermine the competitive position of Colorado producers. In short, there is a major structural shift in the market.

## Study Objective

The purpose of this study is to draw conclusions about the nature of the present decline. The question to be addressed is whether the present decline represents a short term fluctuation and a rebound is imminent or, alternatively, whether it is symptomatic of a long term decline due to a deterioration of Colorado's competitive position in the national coal market.

## Background

The existing literature on the future of the Colorado coal industry contributes little to an understanding of the present situation. All of the projections made in the past two years have forecast steady and strong growth for the Colorado industry. None predicted the present decline.

Recent projections have taken one of two forms. They are either outputs from linear programming or econometric models, or reflect "bottoms up" analysis. The DRI/Zimmerman model of Data Resources, Inc. and the National Coal Model (NCM) of the Department of Energy are examples of the first type of projection (DOE, 1983). The DRI/Zimmerman model uses econometric and statistical techniques to generate its forecasts. The National Coal Model is a large linear program. Both models generate a set of supply curves which project production as a function of F.O.B. mine prices; project demand as a function of consumption by utilities, industrial users and coking operations; and input rail tariffs exogenously. The production projections represent the total "least cost" purchases of coal by consumers from each supply region. In 1983, the NCM projected that Colorado coal production would rise to 22.04 million tons in 1985, 24.59 million tons in 1990 and 30.24 million tons in 1995 from a 1980 base of 18.59 million tons (DOE, 1983).

Two reports from the Colorado Energy Research Institute (CERI) published during 1983 are examples of the second type of analysis. These studies, "Prospects for Colorado Coal" (CERI, 1983) and "Colorado Energy Production Forecasts to the Year 2000: Background Papers" (CERI, 1982) project production based on productive capacity, utility sales and power plant capacity expansion data. The projections generated by these analyses show the Colorado industry to expand to 23.1 million tons in 1985, 32.6 million tons in 1990 and 32.4 million in 1995.

The strong growth predicted by the CERI and NCM forecasts imply that the production decline of 1983 is a short term market fluctuation. By 1985, these models predict the Colorado industry will rebound and growth will return.

Several indicators suggest a contrary scenario. In 1982, utilities consumed about 75 percent of the state's total production (EIA, 1983). Using this ratio of utility sales to total production, the CERI projections imply that about 17 million tons will be sold to the utility industry in 1985. By 1990 utility sales will reach over 24 million tons. A recent unpublished report of the Colorado Department of Natural Resouces states that as of December 1983, Colorado producers have contractual obligations to utilities totalling 12.7 million tons in 1985 and 10.2 million tons in 1990 (CDNR, 1984). Although it is likely that new contracts will be signed, one must ask whether the future demand will be sufficient to make up the difference between present obligations and the projected production.

## Methodology

As stated earlier, the question to be addressed by this study is whether the present decline reflects short term market fluctuations, or, alternatively, whether it is a long term trend--symptomatic of a deterioration in the competitiveness of the Colorado industry. To answer this question, the study will focus on the purchasing habits of the utilities that have bought coal from Colorado producers since 1978. The objective of the analysis will be to determine the role played by Colorado coal in the fuel supply strategy of each utility, identify relevant trends in their supply practices, and identify probable fuel supply practices through 1990. The information gained from these utility reviews will be synthesized and conlusions drawn as to the nature of the present decline.

## Report Overview

The study is organized as follows. Chapter 2 will describe briefly the Colorado coal industry. Each region in the state will be evaluated regarding production levels, mining techniques, size of the reserve base and coal quality. Also included in the chapter will be a discussion of the markets for Colorado coal, their respective size and their location. Chapter 3 will examine the Colorado utility market. Chapter 4 will be a series of case studies, one for each non-Colorado utility that has purchased coal from Colorado mines since 1978. Conclusions will be discussed in Chapter 5.

# Chapter 2

# Overview of the Colorado Coal Industry

Coal was first produced in Colorado prior to 1860, although no records were kept. Since 1864, the first year that records were kept, 723.8 million tons have been produced in the state according to the Colorado Geological Survey (CDM, 1980). In 1983 Colorado mines produced 16.7 million tons, approximately 2.3 percent of the 718.8 million tons produced in the country (CDM, 1983). What types of coals are found in the state and where are they located?

This chapter will address these questions. The major coal reserves in the state will be identified and their quality described. This chapter will conlude with a brief discussion of recent production and general market trends.

## Colorado's Coal Reserves: Their Location and Quality

Coal is found in sixteen counties of Colorado. These counties aggregate to form seven geological coal regions: the Green River, North Park, Uinta, San Juan, Canon City, Denver, and Raton Mesa.

Figure 2.1 shows the location of these regions. The Green River region encompasses the western half of Routt county and the northeastern corner of Moffat county. The North Park region lies in Jackson and Grand counties. The Uinta region, the largest coal producing region in

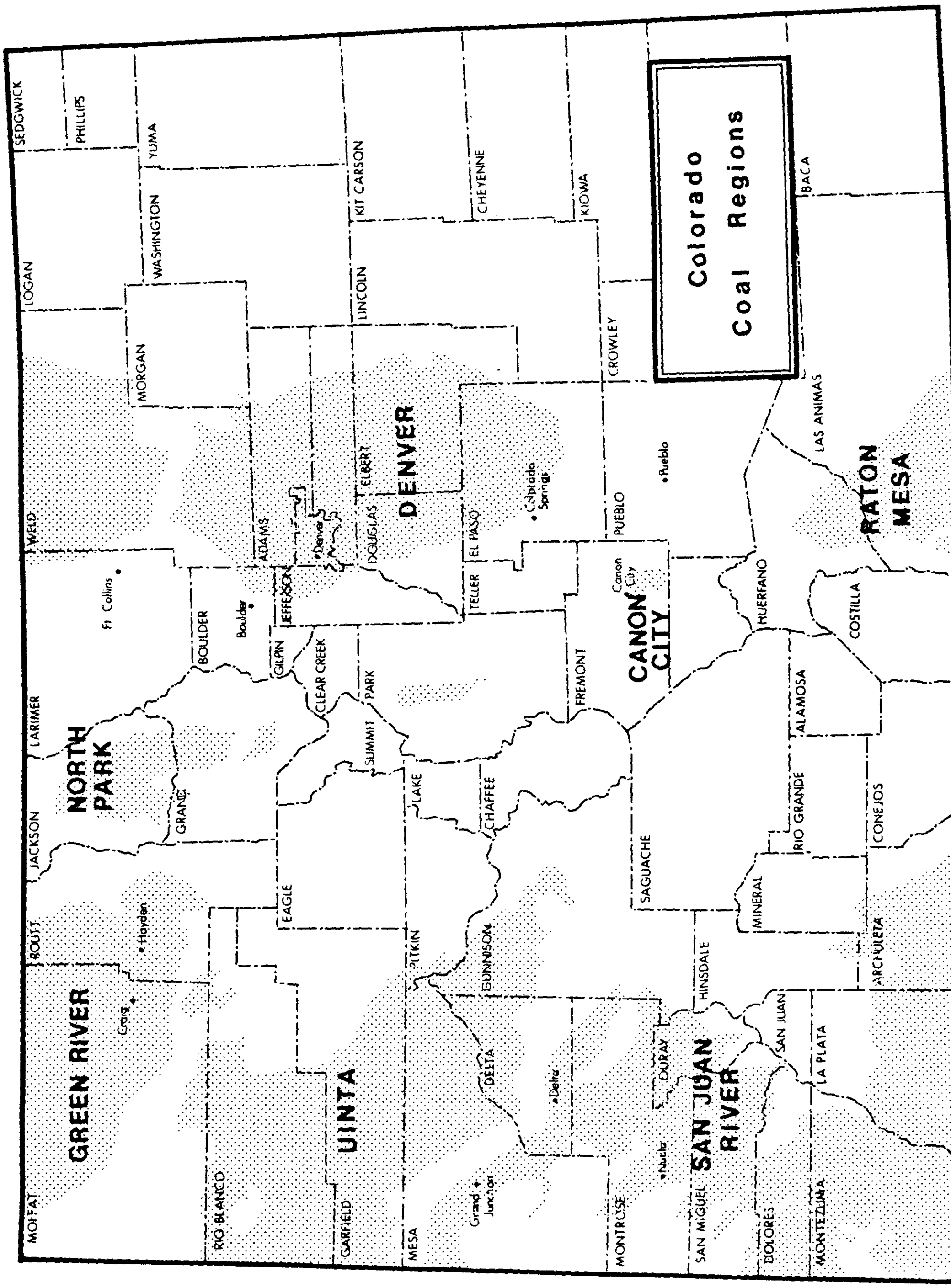


Figure 2.1
Colorado Coal Regions

the state, stretches south from the southern border of Moffat county through Rio Blanco, Garfield, Mesa and Delta counties. The western edge of the Uinta region is the Utah state line. Pitkin, Gunnison and Garfield counties constitute the region's eastern edge. The San Juan region lies in the Southwest corner of the state and includes section of Archuleta, La Plata, Montezuma, Delores, San Miguel, Ouray and Montrose counties. The Raton Mesa region lies in Huerfano and Las Animas counties. The Canyon City region, considered by some to be a northern extension of the Raton Mesa region, lies in Fremont county. The Denver region covers parts of the Front Range counties of Denver, Douglas, Elbert, El Paso, Arapahoe, Adams, Boulder, Jefferson, Adams and Weld.

The seven Colorado coal regions contain approximately 16.215 billion tons of measured and indicated coal reserves. Table 2.1 identifies the reserve base of each coal region in the state. The Green River region contains approximately 6.5 billion tons, about 40 percent of the total. The Denver region with over 3.7 billion tons of coal is the second largest coal region in the state, but most of these reserves are comprised of lignite and other low quality coals. The Uinta region is the third largest region in the state with 3.0 billion tons of reserves. The San Juan region is estimated to contain approximately 1.3 billion tons of reserves. The North Park, Raton Mesa, and Canon City are estimated to hold approximately 813.5, 672.0 and 107 million tons respectively (Boreck and Murray, 1979).

Table 2.1

Coal Reserves of Colorado Coal Regions

| Coal Region | Reserves (MM TONS) |
|---|---|
| Denver | 3,743.85 |
| Canon City | 107.00 |
| Green River | 6,565.49 |
| North Park | 813.48 |
| Raton Mesa | 672.47 |
| San Juan | 1,324.67 |
| Uinta | 2,986.37 |
| Total | 16,215.33 |

Source: Boreck, D.L. and Murray, Keith, Colorado Coal Reserves Depletion Data & Coal Mine Summaries, Colorado Geological Survey, Open-File Report 79-1, May, 1979.

Bituminous coals are located in the Canon City, Raton Mesa, San Juan and Uinta and sections of the Green River regions. Subbituminous coals comprise the majority of the reserve base in the Green River and North Park. Anthracite is only located in the Unita region. Metallurgical coals are found in both the Raton Mesa and Uinta regions. The Denver region contains primarily lignite, but also holds some subbituminous coals. Table 2.2 compares the Btu, sulfur and ash content of reserves from each region based on drilling samples reported to the Colorado Geological Survey (Murray, 1979).

Table 2.2

Quality of Colorado Coals

| Region | Heat Content (Btu/LB) | Sulfur Content (%) | Ash Content (%) |
|---|---|---|---|
| Canon City | 10,400-11,390 | 0.3-1.7 | 4.6-14.8 |
| Denver | 3,636-10,810 | 0.2-1.1 | 3.5-44.6 |
| Green River | 8,250-12,560 | 0.2-1.8 | 3.0-20.2 |
| North Park | 6,520-11,280 | 0.2-1.0 | 2.1-19.2 |
| Raton Mesa | 10,169-13,510 | 0.4-1.3 | 5.3-21.8 |
| San Juan | 9,350-13,380 | 0.5-1.3 | 3.4-26.6 |
| Uinta | 8,298-15,190 | 0.3-2.2 | 2.1-23.3 |

Source: Murray, D. Keith, 1979 Summary of Coal Resources in Colorado, Special Publication 13, Colorado Geological Survey, 1980.

Although the state contains a diversity of coals, the vast majority of coal that is sold to utility customers is bituminous. Table 2.3 compares the weighted average quality of coal sold to utilities during 1982 from mines in each region. These data provide more accurate information about the quality of mineable coal because much of the skewing caused by unmineable or uneconomic resource pockets are eliminated. Table 2.3 shows that all regions in the state produce relatively homogenous high Btu and high sulfur coals. However, the Uinta region produces the highest quality coal based on heating value.

## Production History

Total production in the state rose from 6.03 million tons in 1970 to

19.3 million tons in 1981, a 220 percent increase. However, since 1981 production has fallen by 13 percent, reaching 16.7 million tons in 1983.

Table 2.3

Quality of Coal Sold to Utilities From Colorado Mines During 1982

| Coal Region | Heat Content (Btu/lbs) | Sulfur Content (%) |
|---|---|---|
| Canon City | 10,859 | 0.62 |
| Green River | 10,479 | 0.47 |
| North Park | 10,606 | 0.30 |
| Raton Mesa | 10,222 | 0.50 |
| San Juan | 11,644 | 0.84 |
| Uinta | 12,241 | 0.46 |

Source: Energy Information Adminsitration, U.S. Dept. of Energy, Form 423 1982.

Mines in the Green River region accounted for the 48 percent of the state's production in 1982. Due to the region's relatively thin overburden conditions and thick seams, coal from this region is mined primarily by surface techniques. Getty, Utah International, and Gulf operate large surface mines in the Green River region each capable of producing more than two million tons annually. These large operations have held a consistently large share of the states total production (CDM, 1982).

The Unita region is the second largest producing region in the state, but during the past thirteen years this region has shown the largest relative growth. In 1970 the Uinta region produced approximately 2 million tons or 33 percent of the state total. By 1982 the region produced 7.8 million tons which amounted to over 42 percent of the state total (CDM, 1982). This growth reflects the high demand for the region's relatively high quality coal. The Uinta region is dominated by large underground mines in the 500,000 to 1 million ton category (CDM, 1982).

In 1983 the Canon City region ranked as the third largest source of coal in Colorado. Between 1970 and 1983 the Canon City region produced between one and five percent of the state's total production. The proximity of the mines in this area to the local utility markets in Pueblo, Colorado Springs and Canon City ensure their competitiveness, thus their consistent performance (CDM, 1982).

In 1970 the Raton Mesa region produced about 10 percent of the state's total output, but by 1983 the region produced only one percent. The underground mines in the Raton region produce primarily a coking coal--the Colorado Fuel & Iron mill in Pueblo has been the principal buyer. Production in the region increased in the 1978-1981 period due to the boom in demand for steel products by, among others, the oil and gas industry. When the oil and gas depression and general economic recession hit in 1981 and 1982, CF & I cut back production, which in turn reduced their need for coal. In 1983 CF & I did not use their coke ovens and sold their Colorado mines. The new owners do not have plans to reopen the mines in the near future (Colo. Business Journal, 1984).

Three surface mines consitute the North Park coal industry. While this region has historically been one of the state's largest producing regions--the 75 million tons of cumulative production in Jackson county through 1978 made that county the third most productive county in the state behind Las Animas and Routt--the present mines only became active in 1975. Production in this region grew to 810,000 tons in 1980 but dropped to slightly over 150,000 in 1983. In 1983 this region produced only about one percent of the state's output (CDM, 1982).

Historically, the Denver region has also been a large coal mining area of the state. Weld county, where most of the active mining has taken place over the years, ranks fourth behind Jackson county in cumulative production. However, in 1983 only one mine was active, the Keenesburg mine of the Adolph Coors Co. (CDM, 1982). This mine produces coal which is burned at the Golden brewery.

Since 1970 the San Juan region has produced a consistent one to two percent of the state's total output. In 1983 approximately 360,000 tons were mined in the region. One operation, the Chimney Rock Strip mine in Archuleta county, produced 70 percent of the coal mined in this region. Several other small underground and surface operations constitute the balance of the industry (CDM, 1982).

## The Markets for Colorado Coal

Thus far we have discussed recent production trends in the state. But what is the market for Colorado coal? What sectors burn coal produced in the state and where are they located?

Table 2.4 compares the annual purchases of Colorado coal by the utility, coking, other industrial and other non-industrial sectors since 1978. Throughout this period the utility industry purchased the largest quantity of coal from mines in the state, approximately 85 percent of total sales. The "other industrial" sector, which includes cement plants, breweries, sugar beet plants, and other types of processing plants, was the second largest consuming sector.

Until 1983 the coking coal market was the third largest market for Colorado coal. Coking coal produced in the Uinta region traveled to steel mills in Utah and California, and from Raton Mesa mines to the CF & I mills in Pueblo. In 1982 the mills in Utah and California cutback production considerably and, as mentioned above, in 1983 CF & I shut their coking operation down permanently. Consequently, the demand for coking coal from the state was all but eliminated in 1983.

The "other" category includes purchases of coal for residential uses, primarily heating. Sales of coal to this sector doubled between 1978

Table 2.4

Consumption Patterns for
Colorado Coal: 1978-1983
(Million Tons)

| Sector | 1978 tons | % | 1979 tons | % | 1980 tons | % | 1981 tons | % | 1982 tons | % |
|---|---|---|---|---|---|---|---|---|---|---|
| Utility | 10.2 | 85 | 14.1 | 85 | 14.3 | 84 | 14.9 | 85 | 13.8 | 85 |
| Coking | .7 | 6 | 1.1 | 7 | 1.0 | 6 | .9 | 5 | .4 | 3 |
| Other Indust. | 1.0 | 9 | 1.3 | 8 | 1.6 | 9 | 1.6 | 9 | 1.9 | 11 |
| Other | .1 | 0 | .1 | 0 | .1 | 1 | .1 | 0 | .1 | 1 |
| Total | 12.0 | 100 | 16.6 | 100 | 17.0 | 100 | 17.5 | 100 | 16.2 | 100 |

Source: Energy Information Administration, U.S. Dept. of Energy, Coal Distribution Report, 1978-1982.

and 1980 reflecting the increasing cost of electricity for home heating and the subsequent switch to alternative fuels. Since 1980, however, sales have fluctuated, hovering around 100,000 tons.

Utility demand for coal is spread throughout several states. Table 2.5 identifies the states in which these utilities are located and the tonnages purchased annually since 1978.

Several Colorado utilities provide the largest market for Colorado coal. In 1978 they consumed slightly more than 6 million tons, 59 percent of the total utility market. Purchases by Colorado utilities peaked in 1979 at approximately 8.5 million tons then began a slow

Table 2.5

Utility Consumption of
Colorado Coal: 1978-1983

| | 1978 | | 1979 | | 1980 | | 1981 | | 1982 | | 1983 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| State | ton | % | ton | % | ton | % | ton | % | ton | % | ton | % |
| IL | 1.7 | 17 | 1.8 | 13 | 1.6 | 11 | 2.0 | 14 | 1.4 | 10 | 0.6 | 5 |
| IN | 0.5 | 5 | 1.2 | 9 | 1.0 | 7 | 0.8 | 5 | 1.0 | 7 | 0.7 | 6 |
| IA | 0.6 | 6 | 0.3 | 2 | 0.4 | 2 | 0.4 | 3 | 0.1 | 1 | 0.3 | 2 |
| KS | 0.1 | 1 | 0.4 | 3 | 0.3 | 2 | 0.3 | 2 | 0.0 | 1 | --- | 0 |
| MO | 0.6 | 6 | 0.9 | 6 | 0.7 | 5 | 0.5 | 3 | 0.2 | 1 | --- | 0 |
| NE | 0.3 | 3 | 0.3 | 2 | 0.2 | 1 | 0.1 | 1 | 0.2 | 2 | 0.0 | 0 |
| MS | 0.3 | 3 | 0.7 | 5 | 0.7 | 5 | 0.8 | 5 | 0.8 | 6 | 1.0 | 8 |
| TX | 0.0 | 0 | 0.0 | 0 | 1.0 | 7 | 1.8 | 12 | 2.0 | 15 | 2.1 | 17 |
| CO | 6.0 | 59 | 8.5 | 61 | 8.4 | 59 | 8.3 | 55 | 8.1 | 58 | 7.6 | 62 |
| Total | 10.2 | 100 | 14.1 | 100 | 14.3 | 100 | 14.9 | 100 | 13.8 | 100 | 12.2 | 100 |

Source: Energy Information Administration, U.S. Department of Energy, Form 423 1982.

decline to the 1983 level of 7.6 million tons. Throughout the six year period, the share accorded to Colorado utilities has remained relatively constant, ranging from a low of 55 percent in 1981 to a high of 62 percent in 1983.

Utilities in Texas and Mississippi provide the only examples of a constantly growing market between 1978 and 1983. Accordingly, they were the second and third largest market shares in 1983, 17 and 8 percent respectively. Also in contrast to the Colorado utility market, only one utility in each state buys its coal from Colorado producers: Central

Light and Power in Texas and Mississippi Power in Mississippi.

Table 2.5 also shows that the market share sold to all other states has declined since 1978. The largest decline involved utilities in Illinois. which purchased 1.7 million tons of Colorado coal in 1978 but only 0.5 million tons in 1983. During the period the percent of total utility sales fell during the period from 17 percent to 5 percent. Declines in quantity purchased and market share also occurred in Indiana, Iowa, Kansas, Missouri and Nebraska. Purchases by Kansas and Missouri utilities, which totalled nearly 750,000 tons in 1978 fell to zero in 1983.

Why have the purchases from all but two states declined during the last six years? Will the recent growth markets in Texas and Mississippi continue to expand, providing new opportunities for Colorado producers? Why are Colorado utilities purchasing less Colorado coal? Are they not burning as much coal or do Colorado producers have successful competitors for markets in their own state? The remaining chapters of this study will address these questions. Each of the utility markets identified in Table 2.5 will be analysed to identify answers to the above questions.

# Chapter 3

# The Colorado Utility Market

As shown in Table 2.5, Colorado utilities constitute the primary market for Colorado coal. In 1983 they bought approximately 7.6 million tons of Colorado coal, 45 percent of the state's total production. This chapter will examine the Colorado utility market.

## Overview

Four Colorado utilities burn coal to generate electricity: the Public Service Company of Colorado (PSCO), Colorado-Ute (Colo-Ute), the Colorado Springs Department of Utilities (CSDU), and Centel. A fifth utility, the Platte River Authority (PRA), is building a plant that will burn coal starting in 1984. Figure 3.1 identifies the location of the coal burning power plants owned by these utilities.

PSCO, the largest electric utility in Colorado, has six coal burning units: the Arapahoe, Valmont, Cherokee, Comanche, and Pawnee plants, which are located along the populated Front Range; and the Cameo plant located near Grand Junction. In 1982 these plants consumed 7.3 million tons of coal.

Colo-Ute is the second largest coal consuming utility in the state. Its plants, Hayden, Nucla, Bullock and Craig, service the rural areas along the Western slope of the state. In 1982 Colo-Ute consumed approx-

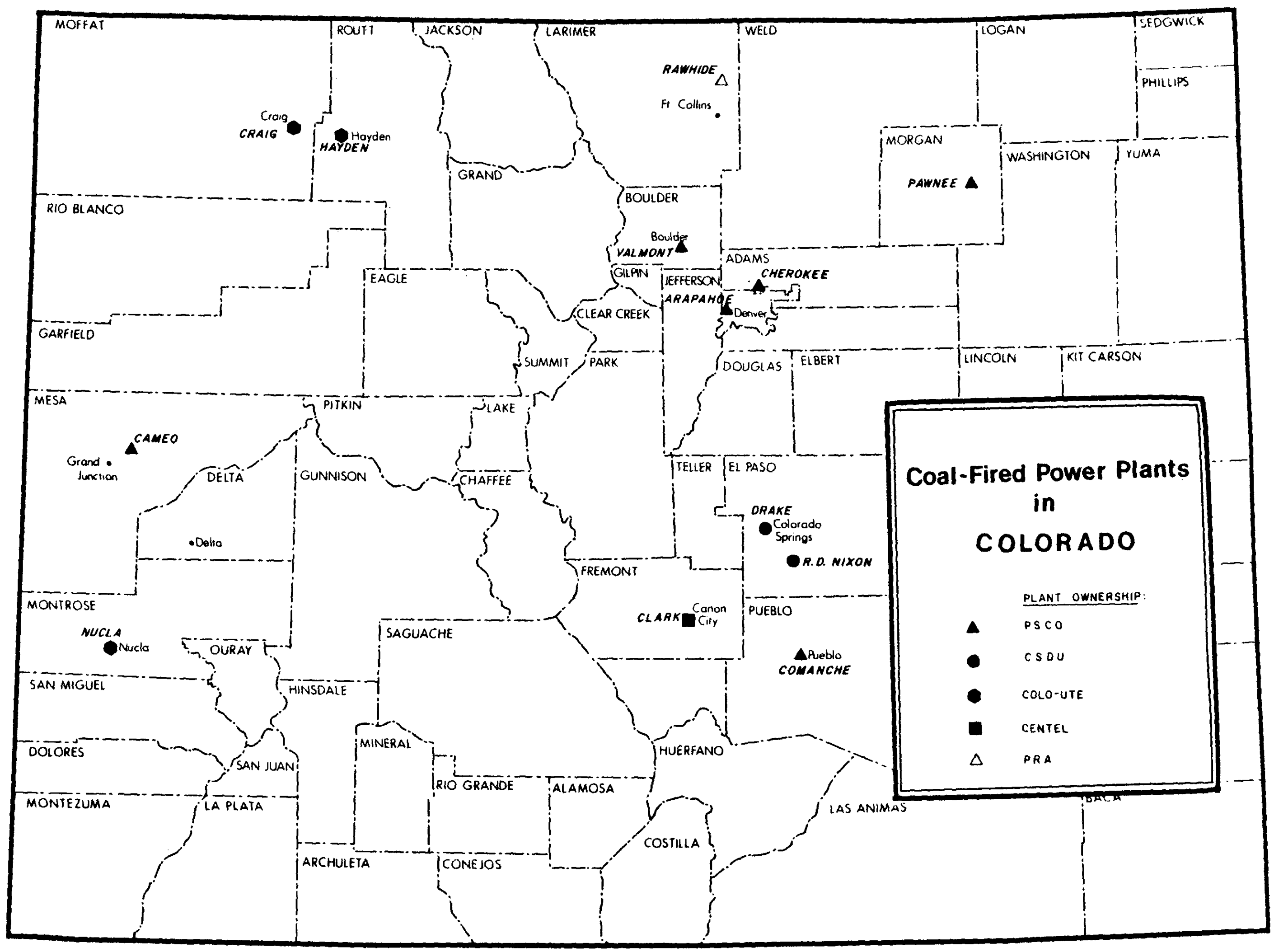


Figure 3.1

Coal-Fired Power Plants in Colorado

imately 3.7 million tons of coal.

CSDU owns the Drake and Nixon plants, which service the area around Colorado Springs and Pueblo. In 1982 these plants consumed approximately 1.3 million tons of coal.

Centel, an Illinois based utility with operations located in Kansas and Colorado, is a small consumer of Colorado coal. It operates the Clark plant, which is located in Canon City. The Clark station provides power to Canon City and other small neighboring towns. In 1982 Centel burned approximately 140,000 tons of coal.

Finally, PRA owns the Rawhide plant near Fort Collins. This plant is scheduled to come on-line in 1984 and consequently has not purchased coal in the past.

## Market Performance: 1978 - 1982

Since 1978 Colorado utilities have increased their consumption of coal by more than 50 percent. Table 3.1 compares the growth in coal consumption for each of the utilities. PSCO, the largest coal consumer, increased its consumption by about 16 percent. Colo-Ute burned about 56 percent more coal in 1982 than in 1978. CSDU consumed 48 percent more coal. Centel's consumption rose by 33 percent between 1978 and 1979 but fell back to a relatively stable 150,000 tons begining in 1980.

Similarly coal purchases by Colordo utilities rose between 1978 and

Table 3.1

Coal Consumption
by Colorado Utilities: 1978-1982
(Million Tons)

| Utility | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|
| PSCO | 6.260 | 6.433 | 5.388 | 6.075 | 7.275 |
| Colo-Ute | 2.660 | 1.959 | 2.705 | 4.123 | 3.965 |
| CSDU | 0.880 | 0.933 | 1.382 | 1.404 | 1.306 |
| Centel | 0.143 | 0.190 | 0.178 | 0.157 | 0.152 |
| PRA | ----- | ----- | ----- | ----- | ----- |
| Total | 9.943 | 9.515 | 9.653 | 11.759 | 12.698 |

Sources: Public Service Co. of Colorado, Annual Report, 1978-1982. Colorado-Ute Electric Association, Annual Report, 1978-1982. Colorado Springs Department of Utilities, Annual Report, 1978-1982. Centel, Annual Report, 1978-1982.

1982. Table 3.2 compares tons purchased by each utility during the period. Overall coal purchases rose by 41 percent from 8.6 million tons in 1978 to 12 million tons in 1982. Colo-Ute purchases increased at the largest rate, 121 percent. CSDU also showed significant gains of slightly more than 99 percent. Purchases by PSCO actually decreased between 1978 and 1981, but rose dramatically in 1982. Centel's purchases rose from 137 million tons in 1978 to 190 million tons in 1980, but then fell back to approximately the 1978 level in 1982.

Consumption of coal grew because coal-fired capacity and power produc-

Table 3.2

Purchases of Coal by
Colorado Utilities: 1978 - 1982
(Million Tons)

| Utility | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|
| PSCO | 6.033 | 6.158 | 5.993 | 5.622 | 6.779 |
| CSDU | 0.728 | 1.234 | 1.308 | 1.304 | 1.452 |
| Colo-Ute | 1.654 | 1.811 | 3.717 | 3.557 | 3.659 |
| Centel | 0.137 | 0.182 | 0.190 | 0.159 | 0.140 |
| Total | 8.552 | 9.385 | 11.208 | 10.642 | 12.030 |

Source: Cost and Quality of Fuel Consumed by Power Plants, Energy Information Administration, US Dept. of Energy, 1978-1982.

tion rose. During the 1978-1982 period total coal-fired capacity increased by 1664.9 MW. Each utility except Centel added capacity during this period. PSCO built the 552 MW Pawnee plant which came on-line in 1981. Colo-Ute added two 446 MW Craig units. Also, the 219 MW Nixon plant was added by CSDU.

Coresponding to the growth in capacity came increased net generation for each utility. Table 3.3 compares net generation--total generation minus plant use--for the coal fired plants of each utility during this five year period. Collectively they produced more than 33 percent more kilowatt hours in 1982 than they did in 1978 as production rose from 17,343,000,000 KWHrs in 1978 to 23,075,000,000 KWHrs in 1982.

Table 3.3

Net Generation for Coal-fired
Power Plants in Colorado: 1978 - 1982
(Million KW Hrs)

| Utility | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|
| PSCO | 12,108 | 13,005 | 10,949 | 11,420 | 12,638 |
| CSDU | 1,698 | 1,820 | 1,566 | 2,706 | 2,544 |
| Colo-Ute | 3,269 | 3,870 | 5,250 | 8,170 | 7,636 |
| Centel | 268 | 261 | 267 | 253 | 257 |
| Total | 17,343 | 18,956 | 18,032 | 22,549 | 23,075 |

Source: Public Service Co. of Colorado, Annual Report, 1978-1982. Colorado-Ute Electric Association, Annual Report, 1978-1982. Colorado Springs Department of Utilities, Annual Report, 1978-1982. Centel, Annual Report, 1978-1982.

Colo-Ute showed the largest increase in output. In 1978 the utility produced 3,269,000,000 KWHrs. In 1982 they produced 7,636,000,000 KWHrs a 134 percent gain. CSDU increased their total generation by 853,000,000 KWHrs, a 50 percent increase. PSCO, on the other hand, only showed a slight 5 percent gain during the period.

Outlook for the Future

There are two ways that Colorado producers can increase the sales of their products to Colorado utiliities. First, they can gain a share of a larger demand: the coal-fired generation capacity of Colorado utilities increases and Colorado producers gain a share of that expanding pie. The second means involves gaining a larger share of the present pie. The balance of this chapter will examine the prospect of Colorado producers expanding their sales to Colorado utilities through both methods.

## Market Size

Although coal consumption by Colorado utilities has grown by almost 40 percent during the past five years, there are numerous indications that the period of growth has ended, at least as far as Colorado producers are concerned.

First, few capacity additions are being planned for the next six years. The PRA will bring the Rawhide plant on-line in 1984. Only PSCO and Colo-Ute are considering building new capacity between 1985 and 1990. PSCO is considering bringing a 520 MW unit on-line at the Pawnee station in 1990 although a firm commitment has not been made. (PSC, 1984). Colo-Ute is completing a new 447 MW unit at the Craig station, but does not plan to bring it on-line until 1986. In 1982 the coal consumption to plant capacity ratio for the Pawnee plant was 3500 tons per megawatt of capacity; for the Craig plant 3000 tons per megawatt. Assuming that the new units for each plant will have the same ratio, these two plant expansions will generate an additional 3 million tons of coal demand.

Capacity is unlikely to expand because expansion is not necessary. Table 3.4 compares the annual utilization rates of each coal-fired power plant since 1978. The utilization rate is defined as the average proportion of the plants capacity that was used during the year (net generation / (nameplate capacity * 8760 hours per year)). For the state taken as a whole, coal-fired power plant utilization went from approximately 65 percent in 1978 to 54 percent in 1982. In other words, plants were being used almost 20 percent less intensively in 1982 than they were in 1978.

Trends for each utility follow that of the state. PSCO's rate fell from 63 percent in 1978 to 53 in 1982. CSDU fell from 65 percent to 59 percent during the period while Colo-Ute's dropped the most dramatically, from 73 percent to 62 percent. The declines of Colo-Ute and CSDU are the most significant because coal is the only fuel source for these utilities. PSCO has hydro, gas, oil and nuclear facilities which can be used to augment the power production of their coal plants. Thus PSCO has maintained a system wide utilization rate of 66.4 in 1978, 68 in 1979, 67.1 in 1980, 67.9 in 1981 and 65.4 in 1982.

Table 3.4 also shows the impact of the capacity expansion that went on in the late 1970s. Before the first 446.4 MW Craig unit was built, Colo-Ute had a relatively high utilization rate--73 percent. After the unit was built in 1979 and the second unit in 1982, the rate dropped to 62 percent. The Nixon plant, a 200 MW addition by the CSDU in 1981,

Table 3.4

Utilization Rates of
Coal-fired Power Plants
in Colorado: 1978 - 1982
(%)

| Utility | Plant | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|---|
| PSCO | Arapahoe | 58 | 75 | 69 | 58 | 43 |
| | Valmont | 54 | 51 | 34 | 44 | 31 |
| | Cherokee | 63 | 67 | 54 | 62 | 50 |
| | Cameo | 76 | 75 | 67 | 60 | 54 |
| | Comanche | 67 | 72 | 63 | 60 | 58 |
| | Pawnee | 00 | 00 | 00 | 5 | 64 |
| | PSCO Ave. | 63 | 68 | 57 | 48 | 53 |
| Colo-Ute | Hayden 1 | 75 | 80 | 60 | 65 | 56 |
| | Hayden 2 | 75 | 85 | 79 | 66 | 66 |
| | Nucla | 54 | 54 | 46 | 26 | 16 |
| | Bullock | 63 | 81 | 55 | 27 | 18 |
| | Craig 1 | 00 | 00 | 00 | 66 | 64 |
| | Craig 2 | 00 | 7 | 55 | 72 | 65 |
| | Colo-Ute Ave. | 73 | 46 | 63 | 66 | 62 |
| CSDU | Drake | 70 | 75 | 64 | 64 | 65 |
| | Nixon | 00 | 00 | 00 | 60 | 50 |
| | CSDU Ave. | 70 | 75 | 64 | 62 | 59 |
| Centel | Clark | 63 | 61 | 63 | 66 | 62 |
| State Average | | 65 | 72 | 68 | 62 | 56 |

Source: Public Service Co. of Colorado, Annual Report, 1978-1982. Colorado-Ute Electric Association, Annual Report, 1978-1982. Colorado Springs Department of Utilities, Annual Report, 1978-1982. Centel, Annual Report, 1978-1982.

lowered the utilization rate of the utility from 75 percent in 1979 to 62 percent.

## Market Share

In 1982, Colordo producers supplied 67 percent of the coal burned by Colorado power plants, and Wyoming mines supplied the balance. Between 1982 and 1990, the opportunities to expand the Colorado share are limited. Two factors explain why: (1) the vast majority of the demand is already under contract; and (2) Colorado producers face stiff competition from Wyoming producers.

Colorado utilities prefer to buy their coal through long term contractual arrangements. Table 3.5 shows the percent of coal bought under long term contracts by each utility between 1978 and 1982. The data indicate that essentially there is no spot market for coal among Colorado utilities. A Colorado producer desiring to sell coal to utilities in the state must rely on long term contracts.

Unfortunately, there are not many opportunities for obtaining contracts with Colorado utilities. Table 3.6 shows the contract obligations of Colorado utilities between 1983 and 1990. The 1982 column shows actual deliveries and can be used for comparison to identify situations where demand is greater than present contract obligations. The table shows that Colorado utilities already have commitments in

Table 3.5

Percent of Coal Purchases
by Colorado Utilities
Made Through Long Term Contracts: 1978 - 1982

| Utility | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|
| PSCO | 100 | 100 | 100 | 100 | 97 |
| CSDU | 100 | 100 | 86 | 100 | 100 |
| COLO-Ute | 100 | 100 | 100 | 100 | 100 |
| CENTEL | 100 | 100 | 100 | 100 | 100 |

Source: Cost and Quality of Fuels, Energy Information Administration, US Dept. of Energy, 1978 - 1982.

excess of what will be needed. PSCO, for example, has 7.4 million tons presently under contract for the year 1990. This constitutes a capacity to consume 10 percent more coal than they did in 1982. Unless the new Pawnee plant is on-line in 1990, PSCO's present commitments seem sufficient to supply their needs. Similar situations exist for each of the other utilties. Even the coal to supply the new Craig unit is already under contract to W.R. Grace.

Table 3.6 also shows the effect of competition, the second factor that will limit the ability of Colorado producers to sell more coal to Colorado utilities. In 1990 PSCO, the utility which consumes the largest quantity of coal, will buy approximately 97 percent of its coal from Amax Coal Co., a Wyoming producer. In yet another example the PRA, owners of the new Rawhide station that is located near Ft. Collins, have

TABLE 3.6

Contracted Commitments of Colorado Utilities
1983-1990
(Million Tons)

| UTILITY | MINING COMPANY | ACT. 1982 | 1983 | PROJ. 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 |
|---|---|---|---|---|---|---|---|---|---|---|
| PSCO | GETTY | 2.06 | 2.20 | 2.20 | 2.20 | 2.20 | 0.00 | 0.00 | 0.00 | 0.00 |
| | ARCO | 0.11 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 |
| | AMOCO | 0.28 | | | | | | | | |
| | OTHER CO | 0.13 | | | | | | | | |
| | TOT. CO | 2.83 | 2.41 | 2.42 | 2.42 | 2.42 | 0.21 | 0.21 | 0.21 | 0.21 |
| | TOT. WY | 3.95 | 5.23 | 5.05 | 5.05 | 5.05 | 7.05 | 7.31 | 7.20 | 7.20 |
| TOT. PSCO | | 6.78 | 7.64 | 7.47 | 7.47 | 7.47 | 7.26 | 7.52 | 7.41 | 7.41 |
| CSDU | AMOCO | 0.42 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 | 0.70 |
| | GULF | 0.44 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 | 0.47 |
| | WR GRACE | 0.59 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 |
| | TOT. CO | 1.45 | 1.77 | 1.77 | 1.77 | 1.77 | 1.77 | 1.77 | 1.77 | 1.77 |
| TOT. CSDU | | 1.45 | 1.77 | 1.77 | 1.77 | 1.77 | 1.77 | 1.77 | 1.77 | 1.77 |
| COLO-UTE | UTAH INT. | 2.30 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 |
| | PEABODY | 1.36 | 1.36 | 1.36 | 1.36 | 1.36 | 1.36 | 1.36 | 1.36 | 1.36 |
| | WR Grace | ---- | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 |
| | TOT. CO | 3.66 | 4.56 | 4.56 | 4.56 | 4.56 | 4.56 | 4.56 | 4.56 | 4.56 |
| TOT. COLO-UTE | | 3.66 | 4.56 | 4.56 | 4.56 | 4.56 | 4.56 | 4.56 | 4.56 | 4.56 |
| PRA | Tot. Co | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| | Tot. Wy | 0.00 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| TOT. PRA | | 0.00 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |

Source: Colorado Department of Natural Resources, Analysis of the Outputs of the Colorado Coal Model, unpublished paper, 1984.

made comittments to buy 100 percent of the plant's coal from the NERCO and ARCO mines in Wyoming.

Consumption of non-Colorado coal by Colorado utilities is not new phenomenon. Table 3.7 traces the mix of states supplying coal to Colorado utilities between 1978 and 1982. Between 1978 and 1981 Colorado producers increased their market share by 3-4 percent a year. However in 1982 that trend reversed and Colorado began to lose market share, dropping back almost to the 1978 level.

The increasing use of Wyoming coal by the Front Range utilities reflects the competitive economics between Colorado and Wyoming suppliers. Table 3.8 compares selected characteristics of coal bought by PSCO between 1980 and 1982. The table shows clearly that Wyoming fuel is less expensive on either a dollar per ton or dollar per million Btu basis. In 1982 Wyoming coal costs $18.38 per ton compared to $28.41 per ton for Colorado coal. On a per million Btu basis Wyoming coal cost PSCO $1.09 compared to $1.31 for Colorado coal.

More important, however, is the rate of fuel cost increases for each source of supply. The cost of Colorado coal increased by $7.24 a ton or 34 percent between 1980 and 1982, compared to $3.51 cents or 24 percent for Wyoming coal. On a per million Btu basis the cost of Colorado coal increased 35 percent compared to 27 percent for Wyoming coal. Looked at another way, in 1980 there was an eleven cent per million Btu difference between Colorado and Wyoming coal. By 1982 that difference had grown to

Table 3.7

Sources of Coal
Consumed by Colorado Utilities: 1978 - 1982
(Million Tons)

| State | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|
| CO | 5.46 | 6.35 | 7.97 | 7.89 | 8.08 |
| WY | 3.09 | 3.04 | 3.21 | 2.52 | 3.95 |
| Total | 8.55 | 9.39 | 11.20 | 10.54 | 12.03 |

Source: Energy Information Administration, US Dept. of Energy Coal Distribution Report, 1978-1982.

Table 3.8

Cost Comparison of Coal Bought by PSCO
from Colorado and Wyoming: 1980 - 1982

| Characteristic | Units | State | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|
| Tons Purchased | 1000 tons | CO | 2781 | 3106 | 2825 |
| | | WY | 3212 | 2516 | 3954 |
| | | Total | 5993 | 5622 | 6779 |
| Ave Heat Cont. | Btu/lbs | CO | 10948 | 10821 | 10851 |
| | | WY | 8641 | 8483 | 8417 |
| Delivered Price | $/mmBtu | CO | 0.97 | 1.14 | 1.31 |
| | | WY | 0.86 | 0.99 | 1.09 |
| Delivered Price | $/ton | CO | 21.17 | 24.57 | 28.41 |
| | | WY | 14.87 | 16.75 | 18.38 |

Source: Guide to Coal Contracts, Coal Outlook, 1983

22 cents. Not only was Colorado coal less competitive than Wyoming coal in 1980, but its competitive position has continued to deteriorate significantly in the past three years.

The following analysis, based on data provided by PSCO to the Federal Energy Regulatory Administration (FERC), provides insights into why Colorado coal is less competitive. Table 3.9 breaks the per million Btu delivered cost of coal into the mine and transportation components for the Getty mine in Colorado and Amax mine in Wyoming contracts. The data show that between 1980 and 1981 the FOB mine price paid for Getty coal rose by 53 percent. During the same period the FOB mine price paid for Amax coal only rose 19 percent. The different cost positions presumably reflect several factors. First, the Getty mine is in the last few years of production and mining relatively expensive reserves, while the Amax mine is in mid-life. Second, the Amax mines are typical Powder River mines in that they are large (greater than 25 million tons annual capacity) and enjoy favorable geological conditions. The Getty mines are smaller, have thinner seams, and therefore higher mining costs. Finally, the Amax contract was originally signed in 1976, the Getty contract in 1979. In 1976 the market price was lower than it was in 1979; thus, some of the present difference was due to the signing dates of the contracts.

Fortunately for Colorado producers, the Colorado Springs Department of Utilities is unable to take advantage of better price of Wyoming

Table 3.9

Components of Delivered Price to PSCO Plants:
A Comparison between the Amax and Getty Mines

| | | 1980 | 1981 |
|---|---|---|---|
| Getty | FOB Destination | .97 | 1.14 |
| | FOB Mine | .58 | .89 |
| | Transportation | .39 | .25 |
| Amax | FOB Destination | .86 | .99 |
| | FOB Mine | .48 | .57 |
| | Transportation | .38 | .42 |

Source: Guide to Coal Contracts, Coal Outlook, 1983.

coal. The boilers at the Drake and Nixon plants are designed to burn Colorado coal. The low ash fusion temperature of Wyoming coal and its relatively lower heat content will not allow it to be burned in the Drake and Nixon boilers. This quality factor forces the utility to pay the premium price for Colorado coals and keeps these plants from switching to the less expensive coals at contract renewal time.

## Conclusions

Colorado utilities constitute the largest segment of the utility market for Colorado coal. In 1982 Colorado's four active electrical utilities, which are located throughout the state, bought about 8.1

million tons of Colorado coal which constitutes about 67 percent of the total utility market for Colorado coal.

Coal demand by Colorado utilities expanded by 28 percent between 1978 and 1982. This corresponded to a 33 percent increase in generation from coal-fired plants in the state during the same period.

Capacity additions that are definite include the Platte River Authority 279 MW Rawhide plant and the 447 MW Craig unit being built by Colorado-Ute. The Public Service Company may build a new unit at their Pawnee station, which would be on-line in 1990, but a final decision to build has not been made.

The Platte River and Colorado-Ute units will only add about 2.1 million tons of new coal demand. Both have already contracted for their coal supply. The Platte River plant will purchase about 800,000 tons from Wyoming producers. The Colo-Ute plant will burn 1.3 million tons of Colorado coal. The new Pawnee unit, when built, will probably burn Wyoming coal.

Wyoming producers constitute the competitive threat to Colorado coal operators servicing the Colorado utility market. In 1982 Wyoming mines supplied 3.95 million tons of coal to utilities along the Front Range of Colorado, which amounted to about 33 percent of the total Colorado utility market. Based on present contract obligations, however, by 1990 Wyoming mines almost exclusively will serve the Public Service Company's Front Range stations and the total coal needs of the new Platte River

Authority station. Conversion to Wyoming coal by these two utilities alone will drop Colorado producers' market share in their own state to approximately 46 percent.

Since the Colorado Springs Utility and Centel are not likely to change their coal burning habits, due to boiler specification and favorable location issues respectively, it appears that the market share of the Colorado utility market accorded to Colorado producers will stabalize at about the 45 - 50 percent level. Unless something can be done to make Colorado coal more competitive along the eastern slope, any new plants in that part of the state will probably burn Wyoming coal. On the other hand, new plants built on the western slope of the state will burn Colorado coals.

# Chapter 4

## Non-Colorado Utility Markets

Utilities located in eight states other than Colorado have bought coal from Colorado producers since 1978. These utilities combined to purchase 4.6 million tons of Colorado coal in 1982, approximately 38 percent of the total sold to the utility market. This chapter will review the purchasing habits of each non-Colorado utility that has bought coal from Colorado producers since 1978 and discuss the likelihood and magnitude of their future purchases.

### Illinois Power

Illinois Power (IP) is a public utility servicing areas throughout Illinois. Its service area has a population of approximately 1,405,000. Major communities served include Decatur, Bloomington, Champaign, La Salle, Madison, Monmouth, Urbana and Peru.

In 1982 total operating revenues were $681 million. About 17 percent came from customers in northern Illinois, 42 percent from central Illinois and 41 percent from southern Illinois. Commerical and industrial customers accounted for $394 million or 58 percent of the total. Major industrial activities include the milling of agricultural products, coal mining, and the manufacture of shoes, automobile parts, chemicals, tires and earth moving equipment. Residential sales during the year contributed $232 million, or 32 percent of the total (Moody's, 1983).

Seven fossil fuel plants comprise the Illinois Power system. Three are fueled by coal and either oil or gas; two exclusively by coal; and two by oil and gas. Table 4.1 identifies each Illinois Power plant, its size and fuel type. Total capacity of the system is 3948 MW. Ninety-six percent of the total system capability is coal fired. Illinois Power is not planning or presently constructing new capacity to be brought on-line before 1990 (Electric World, 1982).

In 1976 Illinois Power contracted with the then Energy Fuels Corporation, which has since been bought by Getty Oil Co and renamed the Colorado Yampa Coal Co. The contract calls for delivery of 830,000 tons (plus or minus ten percent) to be delivered annually through May 1986. (Coal Outlook, 1983) This coal is to be burned at the Wood River plant; spot shipments have also been made to the Baldwin and Havana plants. Table 4.2 compares the total annual tonnages sold to Illinois Power since 1979 to the quantity sold from Colorado Yampa mines. Although deliveries of Colorado Yampa declined after 1981, they have not declined in proportion to total deliveries to all IP plants. Throughout the period, Colorado Yampa supplied a consistent 11 to 12 percent of the coal burned by IP each year.

Colorado Yampa plays a specific role in the fuel supply program of Illinois Power. Although Colorado Yampa supplies only about 12 percent

Table 4.1

Description of Power Plants
Owned by Illinois Power

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Baldwin | 1,892.0 | Coal |
| Havana | 718.0 | Coal/Oil |
| Hennepin | 306.0 | Coal/Gas |
| Vermillion | 182.0 | Coal |
| Wood River | 650.0 | Coal/Gas |
| Oglesby | 70.0 | Gas/Oil |
| Stallings | 95.0 | Gas/Oil |
| Other Small Plants | 33.0 | Hydro/Diesel/Gas |
| Total | 3,948.0 | |

Source: Electric World, Directory of Electric Utilities, McGraw Hill, New York, NY 1982.

Table 4.2

Comparison of Total Deliveries to
Deliveries from Colorado Yampa
1979 - 1983
(MM TONS)

| | 1979 | % | 1980 | % | 1981 | % | 1982 | % |
|---|---|---|---|---|---|---|---|---|
| Colorado Yampa | 0.820 | 11 | 0.912 | 12 | 0.793 | 12 | 0.775 | 12 |
| Other | 6.869 | 89 | 6.475 | 88 | 5.819 | 88 | 5.862 | 88 |
| Total | 7.689 | 100 | 7.387 | 100 | 6.612 | 100 | 6.637 | 100 |

Source: Energy Information Administration, Form 423, Department of Energy, 1979 - 1982.

of the Illinois Power coal needs, it supplies 100 percent of the coal consumed at the Wood River plant and in 1983 supplied on a spot basis approximately 86 percent of the coal burned at the Havana plant (EIA, 1983). Table 4.3 compares the quantity of coal bought, its average sulfur content, cost, and the utization rate for 1982. The data show that relative to the other coal fired Illinois Power plants, the Wood River and Havana plants burn a significantly lower sulfur and more costly coal. In addition, and as a consequence, they are utilized less intensively.

Table 4.3

Quantity Delivered, Average Sulfur Content, Cost and Utilization Rate for Illinois Power Plants in 1982

| Plant | Quantity Delivered (MM TONS) | Average Sulfur Content (%) | Average Delivered Price ($/MMBTU) | Average Utilization Rate (%) |
|---|---|---|---|---|
| Baldwin | 4.642 | 2.92 | 1.33 | 60 |
| Havana | 0.327 | 0.67 | 2.76 | 10 |
| Hennepin | 0.199 | 2.31 | 1.99 | 54 |
| Vermilion | 0.551 | 2.25 | 1.30 | 64 |
| Wood River | 0.775 | 0.66 | 2.41 | 32 |

Source: Energy Information Administration, Form 423, Department of Energy, 1982.

It is unlikely that sales to IP will increase. In 1982 the Denver & Rio Grande Western quoted $27.68 per ton for shipments of 790,000 tons from the Colorado Yampa mine to Federal, IL where the coal is unloaded for the Wood River station (D&RGW, 1982). Assuming that the heat content of the coal was 10,600 Btu (the contract stipulated heat content) the D & RGW rate is the equivalent of $1.31 per million Btu. (27.68/((10,600 *2000)/1,000,000)). In other words, the transportation component of the price paid for Colorado coal is approximately equal to the total cost of the high sulfur Illinois coal that supplies the Baldwin and Vermilion plants, and is about 66 percent of the cost of the coal that supplies the Hennepin plant. Colorado Yampa clearly is not competitive for high sulfur component or approximately 88 percent of the total Illinois Power coal demand.

Competition exists, however, for the low sulfur portion of the Illinois Power market. Other contract suppliers of low sulfur coal are include Reading and Bates and Blue Diamond in Kentucky. Table 4.4 compares the quantity delivered and the associated delivered cost on a $/MMBtu basis for 1981 and 1982. In 1983 Reading & Bates did not deliver coal to Illinois Power, Blue Diamond only sold 15,000 tons at $2.94, and Colorado Yampa sold 562,400 tons at an average price of about $2.60. Since 1981, Colorado Yampa has been the low priced supplier of low sulfur coal to IP plants.

How well Colorado Yampa competes in the future depends on its own price flexibility and that of the D & RGW. The present contract extends until 1986 and contains an option for an additional ten years (Coal Outlook, 1982). The contracts of Reading & Bates and Blue Diamond expired in 1982 and 1983 respectively. Thus, in 1986 when their contract expires, Colorado Yampa has the advantage of an incumbent. However, during the past three years the delivered price of Colorado Yampa coal has risen an average of almost 9 percent annually. Continuation of this trend would bring the price of this Colorado coal to more than $3.00 by 1985. At that price, low sulfur coals from Kentucky and West Virginia should become strong economic competitors.

Table 4.4

Comparison of Delivered Tonnage and Cost for Low Sulfur Coal Purchased by Illinois Power: 1981 and 1982

| Supplier | 1981 Quantity Delivered (MM TONS) | 1981 Average Cost ($/MMBTU) | 1982 Quantity Delivered (MM TONS) | 1982 Average Cost ($/MMBTU) |
|---|---|---|---|---|
| Colo. Yampa | 0.793 | 2.21 | 0.775 | 2.41 |
| Reading & Bates | 0.326 | 2.42 | 0.182 | 2.49 |
| Blue Diamond | 0.328 | 2.69 | 0.243 | 2.89 |

Source: Energy Information Administration, Form 423, Department of Energy, 1981 - 1982.

## Central Illinois Light Company

The Central Illinois Light Co. (CILCO) is a public utility servicing central Illinois centering around Springfield and Peoria. Electricity is distributed to 137 communities with a combined population of over 430,000 (Moody's, 1983).

In 1982 total operating revenues were $282 million. Industrial and commercial users acounted for the $171 million or 61 percent of the total. The primary manufacturing industries served by CILCO were food and kindred products ($5.8 million), primary metals ($28.7 million),and non-electrical machinary ($35.4 million). Residential customers generated $106 million or 38 percent of total revenues (Moody's, 1983).

CILCO has four fossil fuel power plants with a combined capacity of 1,533 MW. Three are coal fired units-- the Wallace, Edwards, and Duck Creek plants--and the fourth is gas fired. Table 4.5 identifies the various plants, their size and fuel type. Coal is the fuel source for more than 97 percent of the system's capability. There are no plans for the contruction of additional capacity between 1983 and 1990.

Between 1980 and 1982 Colorado coal was sold to the Edwards plant in Peoria. The contract, which was signed in October 1978 with West Slope Carbon Inc., called for 360,000 tons in 1979, and for 600,000 tons in 1980 and thereafter until 1994. The contract was cancelled in December 1982 for economic and quality reasons (CILCO, 1983).

Table 4.5

Description of Power Plants
in the CILCO System

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Wallace | 305.0 | Coal/Gas |
| Edwards | 780.0 | Coal/Gas |
| Duck Creek | 417.0 | Coal |
| Sterling Ave. | 32.0 | Gas |
| Total | 1,533.0 | |

Source: Electric World, Directory of Electric Utilities, McGraw Hill, New York, NY 1982.

Although Colorado coal was not sold to Central Illinois Light & Power in 1983, it is instructive to examine CILCO's historic fuel supply cost structure to understand the difficulty that will be faced by a Colorado producer selling coal to CILCO and other mid-western utilities in the future. Table 4.6 compares the quantity, quality and cost of fuel purchased by the utility for each plant in 1982. The table shows that Edwards and Duck Creek plants burn 94 percent of the coal burned by the system and utilization rates of 43 and 52 percent respectively. The Wallace plant was used sparingly during the year.

Table 4.6 also shows that there was a considerable difference between the cost and sulfur content of the fuel burned at the Edwards and Duck Creek plants. The Edwards plant, which is located on the outskirts of

Table 4.6

Quantity, Cost and Quality of Coal
Burned by CILCO
in 1982

| Plant | Quantity Delivered (MM TONS) | Average Sulfur Content (%) | Average Delivered Price ($/MMBTU) | Average Utilization Rate (%) |
|---|---|---|---|---|
| Edwards | 1.179 | 0.53 | 2.37 | 43 |
| Wallace | 0.088 | 0.80 | 2.32 | 7 |
| Duck Creek | 1.161 | 3.46 | 1.87 | 52 |

Source: Energy Information Administration, Form 423, Department of Energy, 1982.

Peoria, burns a relatively low sulfur, high cost coal. By contrast, the Duck Creek plant, which is located near Canton, burns a higher sulfur and less costly coal.

The coal burned at the Duck Creek plant is mined in Illinois and Colorado coal is too expensive to compete for this market. A potential supplier from Colorado must ship its coal via the D & RGW. In 1982 the tariff quoted for shipping 650,000 tons of coal from the West Slope Carbon mine to the Edwards plant in Sommer, IL was $29.28 (D&RGW, 1982). Assuming a heat content of 12265 Btu/lb., the per million Btu equivalent was $1.19. Subtracting the Colorado to Edwards tariff from the average fuel cost incurred at the Duck Creek plant leaves an FOB mine price of $.68 for a prospective Colorado producer.

Low sulfur coal is not found in Illinois, but CILCO's demand is limited to the coal needed to fuel the Edwards and Wallace plants. In 1982, three companies other than West Slope Carbon sold low sulfur coal to these plants: Westmoreland from their Montana mine, and Blue Diamond and Mapco from their mines in Kentucky. Table 4.7 compares the quality and cost of low sulfur coals supplied to CILCO from these mines. The coal purchased from the Westmoreland and Blue Diamond mines was less expensive than that bought from West Slope Carbon. Applying the $1.19 per million Btu tariff incurred when transporting 650,000 tons of coal from the West Slope Carbon mine to the Edwards plant, to the Westmoreland and Blue Diamond delivered price would give a prospective Colorado producer an FOB mine price window of between $1.06 and $1.12 per million Btu.

Table 4.7

Comparison of Cost, Quality and Quantity of Coals bought for Edwards Plant: 1982

| Supplier | Delivered Quantity (MM TONS) | Average Heat Content (Btu/lb.) | Average Sulfur Content (%) | Average Fuel Cost ($/MMBtu) |
|---|---|---|---|---|
| West Slope Carbon | .632 | 12265 | .44 | 2.38 |
| Westmoreland | .204 | 8640 | .69 | 2.31 |
| Blue Diamond | .239 | 13224 | .73 | 2.25 |
| Mapco | .182 | 13133 | .75 | 2.48 |

Source: Energy Information Administration, Form 423, Department of Energy, 1982.

At the 1982 price structure Colorado producers could be competitive. However, in 1983 Blue Diamond and Westmoreland sold 842,000 and 207,000 tons to the plant at an average delivered price of $1.96 and $2.37 respectively. The reduced price implies that a Colorado producer would now need to be able to sell coal at an FOB mine price of between $.77 and $1.18. The Kentucky producers have a clear price advantage.

## Northern Indiana Public Service Company

Northern Indiana Public Service Co. (NIPSCO) is a public utility system servicing the northern third of Indiana. The service area has an estimated population of 2,188,000 and 241 communities. Communities served by NIPSCO include Gary, East Chicago, Michigan City, La Porte and Portage.

Total operating revenues in 1982 were $763 million. The NIPSCO sevice area is heavily industrial. In 1982, approxately $495 million or 65 percent of the utility's operating revenues came from this sector. US Steel and Inland Steel alone accounted for 9 percent of the company's total revenue. Residential customers provide the second largest source of revenues, $185 million or 24 percent. The balance of their revenues came from commercial, street lighting and sales for resale (NIPSCO, 1983).

The NIPSCO system has a total capacity of about 2858 MW. All of NIPSCO's capacity is fueled by either fossil fuels or hydro power. Four coal burning units, the Mitchell, Schaffer, Bailly and Michigan City, have a combined capability of 2841 MW or about 99 percent of the system's total. One additional 344 MW unit came on-line at the Schaffer station in 1983 and another is being built and will be placed into operation in 1986. When operating they will bring the NIPSCO coal fired capacity to 3664 MW. Table 4.8 lists the power stations in the NIPSCO system, their capacity and fuel type.

Table 4.8

Descriptive Information on NIPSCO Power Plants

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Michigan City | 661.0 | Coal/Gas |
| Mitchell | 529.0 | Coal/Coke/Gas/Oil |
| Bailly | 615.6 | Coal/Gas/Oil |
| Schahfer | 1,031.9 | Coal/Coke/Oil |
| Oakdale | 10.0 | Hydro |
| Norway | 10.0 | Hydro |
| Total | 2,857.5 | |

Source: Electric World, Directory of Electric Utilities, McGraw Hill, New York, NY 1982.

In 1977 NIPSCO and Colorado Westmoreland, a subsidiary of Westmoreland Coal Co. entered into a supply contract which called for 1.25 million tons to be delivered annually. The contract expires in 1993. Table 4.9

shows the actual deliveries since 1979 under the contract.

Table 4.9

Deliveries to the Schahfer and Mitchell Plants
by Colorado Westmoreland: 1979 - 1983
(Million Tons)

| Plant | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|
| Michell | 0.763 | 0.743 | 0.635 | 0.100 |
| Schahfer | --- | --- | 0.097 | 0.914 |
| Total | 0.763 | 0.743 | 0.732 | 1.014 |

Source: Energy Information Administration, Form 423, U.S. Department of Energy, 1979 - 1982.

As was the case with CILCO and IP, there is a marked difference between the sulfur content, fuel cost and utilzation rates of plants in the NIPSCO system. Table 4.10 compares the quantity, sulfur content and cost of coal supplied to each of the NIPSCO stations. The Schahfer and Mitchell plants burn a significantly lower sulfur, higher cost coal than the Michigan City and Bailly stations. Also, they are utilized less intensively than either of the high sulfur coal burning stations.

Again, Colorado producers will have difficulty supplying the high sulfur coal market. In 1982, the D & RGW charged $27.22 per ton for transporting 900,000 tons of coal from the Westmoreland mine in

Table 4.10

Quantity, Cost and Quality of Coal
Burned by Northern Indiana Public Service Co.
in 1982

| Plant | Average Quantity Delivered (MM TONS) | Average Sulfur Content (%) | Average Delivered Price ($/MMBTU) | Utilization Rate (%) |
|---|---|---|---|---|
| Michigan City | 1.095 | 2.50 | 2.13 | 36 |
| Bailly | 0.668 | 2.98 | 1.88 | 38 |
| Mitchell | 0.779 | 0.55 | 3.03 | 28 |
| Schahfer | 1.428 | 0.54 | 2.82 | 30 |

Source: Energy Information Administration, Form 423, Department of Energy, 1982.

Colorado to Gary, IN, which is within 100 miles of the Bailly and Michigan City plants. The average heat content of the Westmoreland coal was 11,272 Btu, so the per million Btu equivalent of the D & RGW tariff was $1.21. To compete with the Illinois and Wyoming suppliers for the Michigan City and Bailly plants, the D & RGW tariff would allow a Colorado producer an FOB mine price of $.92 and $.67 respectively.

The NIPSCO low sulfur market is more favorable to Colorado producers. Three Wyoming companies, Carbon County Coal Co., Medicine Bow and Arch Minerals Corp., and Colorado Westmoreland compete to supply the NIPSCO low sulfur coal demand. Table 4.11 compares the quantity, heat content, sulfur content and delivered price for coal coming from each company.

Table 4.11

Comparison of Cost, Quality and Quantity of Coals bought for Schahfer and Mitchell Plant: 1982

| Supplier | Delivered Quantity (MM TONS) | Average Heat Content (Btu/lb.) | Average Sulfur Content (%) | Average Fuel Cost ($/MMBTU) |
|---|---|---|---|---|
| Westmoreland | 1.013 | 11272 | .48 | 2.88 |
| Carbon County | .970 | 11020 | .55 | 3.02 |
| Medicine Bow | .127 | 10190 | .44 | 2.44 |
| Arch Minerals | .077 | 10458 | .70 | 2.50 |

Source: Energy Information Administration, Form 423, Department of Energy, 1982.

All of the suppliers listed in Table 4.11 have contracts extending beyond 1990. In 1981, NIPSCO consolidated the Arch Mineral and Medicine Bow agreements into one contract which runs until 1995. However, in 1982 NIPSCO discovered that they could not burn the Arch/Medicine Bow coal without the installation of a $60 million bag house pollution device at the Schahfer plant. NIPSCO is installing the equipment, but in the meantime has negotiated an agreement with Arch Minerals and Medicine Bow whereby NIPSCO will buy the contracted coal, but leave it in place. NIPSCO can take the coal at any time before 1989 or it can resell the coal (NIPSCO, 1983).

Whether the deferred shipment of the Arch/Medicine Bow coal will provide additional temporary opportunities for Colorado producers is not clear. Preliminary data for 1983 indicates that NIPSCO bought about 335,000 tons of 5.6 percent sulfur to mix with the low sulfur coal purchased from Westmoreland and Carbon County. The price paid for the high sulfur coal was $1.75 per million Btu, considerably below the rate for Wyoming and Colorado low sulfur products (EIA, 1983).

Should NIPSCO decide to buy more western low sulfur coal, the data in Table 4.11 indicate that Westmoreland is the least expensive of their present suppliers. As of January 1984 the D & RGW is charging $29.43 per ton for a 600,000 ton shipment from the Westmoreland loadout to Gary, IN. The equivalent rate on a $/MMBtu basis is $1.30. In 1983 Westmoreland sold their coal to NIPSCO for about $2.85 per million Btu, Carbon County about $3.18 per million Btu, which suggests that a Colorado producer selling coal at an FOB mine price of between $1.55 and $1.88 per million Btu would be price competitive.

## Iowa Electric Light & Power Company

Iowa Electric Light & Power (IELP) is a public utility servicing central and east central Iowa. The service area includes 272 cities, 118 unincorporated communities and has a population of approximately 800,000.

In 1982 IELP had total operating revenues of $246 million. Industrial and comercial customers accounted for $137 million or about 56 percent of the total. Residential and rural customers accounted for an additional $95 million.

IELP is the sole owner of five fossil fuel power stations, owns a 15% interest in the Ottumwa station that is operated by Southern Utilities Co., and owns a 70% interest in one nuclear plant. Their total generating capability is 1048 MW. Coal fuels 487 MW or about 46 percent of their capacity. IELP's coal plants are the Sutherland, Prairie Creek, and Sixth Street stations. One additional station, to be named Guthrie, is being designed and permitted. The Guthrie unit, which will have a net capability of 650 MW, is scheduled to be on-line sometime after 1988. Table 4.12 lists the various power stations in the IELP system, their size and fuel type.

In 1975 IELP entered into a contract with Empire Energy Co, a subsidiary of AMOCO Minerals, to deliver 250,000 tons annually from their Colorado mines to IELP's Prairie Creek and Sixth Street stations. The contract is scheduled to expire in 1985, although amendments have been made that allow for deferred delivery of coal originally scheduled for shipment in 1982. Table 4.13 shows actual deliveries since 1979.

In contrast to CILCO, IP and NIPSCO, IELP does not face tight sulfur emmission restrictions; thus, a regulatory derived demand for low sulfur coal. Table 4.14 shows the quantity of coal burned at each of the IELP stations and the average sulfur content during 1982 and 1981. In 1982

Table 4.12

Descriptive Information on
Iowa Electric Light & Power Plants

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Sutherland | 147.0 | Coal |
| Prairie Creek | 139.0 | Coal |
| Sixth St. | 100.0 | Coal |
| Ottumwa | 101.3 | Coal |
| Peaking Turbines | 203.1 | Oil |
| Diesel Stations | 7.8 | Oil |
| Duane Arnold | 350.0 | Nuclear |
| Total | 1,048.2 | |

Source: Iowa Electric Light & Power, _1982 Annual Report_.

Table 4.13

Deliveries of Coal to IELP Plants
From Empire Energy Mines: 1979 - 1982
(Ths. Ton)

| Plant | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|
| Sixth Street | 26 | 16 | -- | 26 |
| Prarie Creek | 189 | 237 | 235 | 112 |
| Total | 215 | 253 | 235 | 138 |

Source: Energy Information Administration, Form 423, U.S. Department of Energy, 1979 - 1982.

the Sixth Street station burned the lowest sulfur coal, but only 27,000 tons of coal were consumed during the year. The Prairie Creek and Sutherland stations both burned relatively high sulfur coal, 2.3 and 4.0 percent respectively.

Table 4.14

Quantity Delivered and Average Sulfur Content of Coal Purchased by Iowa Electric Light and Power: 1981 & 1982

| Plant | 1981 Quantity Delivered (MM TONS) | 1981 Average Sulfur (%) | 1982 Quantity Delivered (MM TONS) | 1982 Average Sulfur (%) |
|---|---|---|---|---|
| Sixth St. | --- | --- | 0.027 | 0.82 |
| Praire Creek | 0.401 | 1.56 | 0.373 | 2.31 |
| Sutherland | 0.327 | 3.57 | 0.190 | 4.02 |

Source: Energy Information Administration, Form 423, U.S. Department of Energy, 1981-1982.

Historically, the sulfur content at the Prairie Creek station has been significantly lower than indicated for 1982, averaging between 1.5 and 1.7 percent between 1979 and 1981. The lower average sulfur content resulted from a proportionately higher quantity of Empire Energy coal being burned at the plant. In 1982 when the sulfur was 2.3 percent Empire's contribution was about 30 percent of the total coal burned.

However, from 1979 to 1981 between 42 and 59 percent of the coal burned at the plant came from the Empire mines.

The prices that the Iowa and Missouri producers are receiving for their high sulfur coal prohibit competition from Colorado. Table 4.15 shows the quantity sold and the prices received by Missouri Mining and Iowa Coal Sales in 1982 and 1983. In 1983 the D & RGW charged $30.90 per ton to transport coal in 1500 ton shipments from the Empire mine in Colorado to Cedar Rapids where the ILEP plants are located. The average heat content for coal burned by ILEP during the year was approximately 10400 Btu; thus , the per million Btu equivalent of the D & RGW tariff was $1.49. Subtracting this from the prices paid by ILEP for the Missouri and Iowa coal leaves a Colorado producer with a competitive FOB price window of between $.98 and $.50 per million Btu.

Table 4.15

Quantity and Price of Coal
Shipped to Iowa Electric Light and Power:
1982 & 1983

| Supplier | 1982 Quantity Delivered (MM TONS) | 1982 Average Delivered Price ($/MMBTU) | 1983 Quantity Delivered (MM TONS) | 1983 Average Delivered Price ($/MMBTU) |
|---|---|---|---|---|
| Empire Energy | 0.138 | 3.24 | 0.236 | 3.11 |
| American Indust. | 0.338 | 2.34 | 0.244 | 2.47 |
| Iowa Coal Mining | 0.114 | 2.23 | 0.114 | 1.99 |

Source: Energy Information Administration, Form 423, Department of Energy, 1982-1983.

As for the future ILEP low sulfur market, Colorado producers' role is unclear. At least through 1985, when its contract expires, Empire Energy should continue to supply the low sulfur coal needs of ILEP. After 1985, however, competition could develop with Wyoming producers. In 1982 Sunedco supplied 100 percent (1.8 million tons) to the Ottumwa plant in which IELP has a 15 percent interest. The average delivered price of the Sunedco coal was $1.42 per million Btu, approximately 56 percent of the price IELP paid for Empire Energy coal in 1982. Some of the difference can be explained by the fact that the Ottumwa plant is 222 miles closer to the Sunedco mine than the Prairie Creek plant is to the Empire Energy mine. However, using the per ton mile equivalent of the 1983 D & RGW tarrif which was $.03 per ton mile, Empire would face a rail charge of approximately $24.57 per ton for shipments to the Ottuma plant. On a per million basis this equals $1.18. Therefore to be competitive with the Wyoming producers, Empire would have to be willing to sell its coal at about $.24 per million Btu FOB mine.

## Ames Municipal Electric System

Ames Municipal Electric System (Ames) is a municipal system servicing the city of Ames, Iowa, a city of 43,000 people located in the center of the state.

The city has three coal fired units totalling 118 MW and one gas fired unit of 0.02 MW. There are no plans at the present time to expand the system. In fact, their utiliztion rates in 1982 and 1983 were only 15 and 18 percent respectively, indicating that the system could absorb considerably higher electrical demand.

W. R. Grace delivered coal from their Colowyo mine under contract with Ames in 1980 and 1981. In 1980 Colowyo delivered 56,600 tons, or 50 percent of the total deliveries to the plant. In 1981 total coal consumption at the plant fell to 63,000 from 110,000 in 1980. During 1981 Colowyo delivered 43,800 tons, or 68 percent of the total. Since 1981, Colorado producers have not sold any coal to Ames.

Data on deliveries since 1981 suggests why Colorado coal producers lost the Ames market to other suppliers. Table 4.16 compares the quantity and cost of coal delivered to the Ames plant between 1978 and 1983. Between 1978 and 1981 the price Ames paid for coal rose steadily. Annual increases were approximately 16 percent between 1978 and 1979, 10 percent between 1979 and 1980, and 28 percent between 1980 and 1981. Between 1981 and 1982, the priced dropped, reflecting the switch from coal from the Colowyo mine to coal mined in Wyoming.

Colorado producers have a difficult time selling coal at a competitive price to the Ames plant. In 1982 the D & RGW rail tariff from the Colowyo mine to the Ames station was approximately $29.20 or a Btu equivalent of about $1.40 assuming 10200 Btu coal (D&RGW, 1982). During the year Wyoming and Iowa producers sold their coal to Ames at an

Table 4.16

Cost and Quantity of Coal
Sold to the Ames Plant:
1978-1983

| | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|
| Quantity (MM TONS) | 0.142 | 0.175 | 0.111 | 0.063 | 0.130 |
| Delivered Cost ($/MMBTU) | 1.36 | 1.58 | 1.78 | 2.24 | 1.93 |

Source: Energy Information Administration, Form 423, Department of Energy, 1978-1982.

average of $1.93 per million Btu. This implies that to be competitive a Colorado producer would only be able to charge approximately $.53 per million Btu FOB mine.

## Iowa Public Service Company

Iowa Public Service CO (IPSCO) is a public utility servicing northwestern Iowa. The company sells electricity to about 159,000 customers in 228 cities in Iowa and five South Dakota communities. Major cities in the service area include Sioux City and Waterloo.

Total operating revenues for the utility in 1982 were $210 million. Commercial and industrial revenues for 1982 were $106 million or almost 51 percent. Meat packing and processing and other manufacturing plants constitute the largest industrial activities. Residential sales were $81 million. Sales for resale and street lighting accounted for the balance (Moody's, 1983)

IPSCO owns 100 percent of the Maynard coal fired power station and two other oil burning units. In addition IPSCO owns about 52 percent of the coal-fired Neal station in Sioux City and 18 percent of the Ottumwa plant in Ottumwa, Iowa. IPSCO has a total of 1865 MW of coal fired capacity. Table 4.17 describes the power plants in the IPSCO system, their capability and fuel type.

Table 4.17

Description of Power Plants
Owned and Operated by the
Iowa Public Service Company

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Maynard | 77.4 | Coal |
| Neal | 812.0 | Coal/Gas |
| Ottumwa* | 125.0 | Coal/Oil |
| Neal | 5.5 | Deisel |
| Unnamed | 38,0 | Gas/Oil |
| Electrifarm | 194.8 | Oil |
| Total | 1,252.7 | |

*Reflects IPSCO's 18 percent interest. The plant has a total capability of 695 MW.

Source: Electric World, Directory of Electric Utilities, McGraw Hill, New York, NY 1982.

IPSCO purchased approximately 36,000 tons of coal from the Canadian mine in 1980 on a spot basis. Since that year Colorado coal has not been purchased by the utility.

Wyoming mines are the primary suppliers of coal to IPSCO. Table 4.18 shows the mines, the quantity supplied and the delivered price of coal purchased by the Neal plant in 1982 and 1983. (The Maynard plant was inoperative during 1982 and 1983.)

In 1982 the sulfur emission limit for the Neal plant was 1.2 lbs sulfur per million Btu. Given this low sulfur allowance IPSCO will continue to burn low sulfur coal from the West, as western mines are the closest source of supply. Spot sales opportunities are available: in 1983 IPSCO bought 100,000 tons from the Energy Development Wyoming at \$1.74 per million Btu. Additionally, the Medicine Bow supply agreement expires in 1985 and the Peter Keiwit contract in 1989.

Colorado producers will have difficulty re-entering the IPSCO market because Colorado coals are not price competitive to the IPSCO plant. In 1983 the D & RGW single car rail tariff from northwest Colorado to Sioux City where the Neal plant is located was \$26.17. Assuming that a Colorado supplier would sell approximately 10,200 Btu coal, the D & RGW rate per million Btu equivalent rate would have been \$1.28. This rail tariff would only allow the Colorado producer an FOB mine price of from \$.18 to \$.51 per million Btu if they were to be competitive with the prices that the utility received during the year.

Table 4.18

Deliveries to Power Plants
Operated by Iowa Public Service:
1982 & 1983

| Supplier | 1982 Quantity Delivered (MM TONS) | 1982 Average Delivered Price ($/MMBTU) | 1983 Quantity Delivered (MM TONS) | 1983 Average Delivered Price ($/MMBTU) |
|---|---|---|---|---|
| Medicine Bow | 0.472 | 1.65 | 0.461 | 1.77 |
| Carter Mining | 1.732 | 1.59 | 1.439 | 1.52 |
| Resource Explor. | 0.129 | 2.04 | ----- | ---- |
| Peter Keiwit | 0.493 | 1.55 | 0.415 | 1.46 |
| Energy Devel. | 0.386 | 2.09 | 0.392 | 1.79 |
| Royal Fuel (OK) | ---- | ---- | 0.018 | 1.62 |

Source: Energy Information Administration, Form 423, Department of Energy, 1982-1983.

## Kansas Power & Light

Kansas Power and Light (KP & L) is a publically held utility servicing the central portions of Kansas. Electrical services are supplied on a retail basis to 284 communities including Salina, Topeka, Lawrence, Hutchinson, Leavenworth, Manhattan, Emporia, Parsons, Atchison and Abilene.

In 1982 total operating revenues for KP & L for the year were $332 million. Residential sales amounted to $115 million or 35 percent; industrial and commercial sales were $171 million or 52 percent. Major industrial customers included flour mills, steel and iron foundaries, railroad shops, packing plants and salt mines.

KP & L has four wholly owned fossil fuel power plants. Two, the Tecumseh and Lawrence, are combination coal and gas and oil, The other two are gas and oil fired. In addition KP & L holds a 64 percent interest in the Jeffery Energy Center, a 1350 MW station. In all, KP & L has 1564 MW of coal-fired capacity and 2314 MW of total capacity. Table 4.19 lists all the power plants in the KP & L system, their capacity and fuel type. One additional unit is being built at the

Table 4.19

Descriptive Information on
Kansas Power and Light Power Plants

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Tecumseh | 87.0 | Gas/Oil |
| | 217.0 | Coal |
| Total | 304.0 | |
| Jeffery | 865.0 | Coal |
| Lawrence | 34.0 | Gas/Oil |
| | 515.0 | Coal |
| Total | 549.0 | |
| Hutchinson | 493.0 | Gas/Oil |
| Abilene | 103.0 | Gas/Oil |
| Total-Coal | 1,597.0 | |
| Total-Gas/Oil | 717.0 | |

Source: Kansas Power & Light, 10K Report, 1982.

Jeffrey plant. Scheduled to come on-line in 1984 the plant will add 680 MW to the Jeffrey station. KP & L will have a 64 percent share in the new unit.

In 1979 KP & L entered into a three year contract with the Pittsbury & Midway Mining Co. of Gulf Oil Co. to deliver 300,000 tons of coal annually to the Techumseh and Lawrence Energy Centers. Table 4.20 shows the actual deliveries to these stations during the life of the contract. Since the contract expired in January of 1982, KP & L has not purchased any Colorado coal.

The Pittsburg & Midway contract was intended as a short term supply agreement. During the life of the agreement KP & L bought the bulk of their coal from Amax Coal Co. and Arch Minerals. The Amax agreement is in effect until 2013, the Arch contract until 1984. Table 4.21 shows

Table 4.20

Deliveries to KP & L Power Plants
from Pittsburg & Midway Mines: 1979 - 1983
(Million Tons)

| Plant | 1979 | 1980 | 1981 | 1982 | 1983 |
|---|---|---|---|---|---|
| Tecumseh | 89 | 102 | 89 | 3 | -- |
| Lawrence | 231 | 157 | 184 | 3 | -- |
| Total | 320 | 259 | 273 | 6 | 0 |

Source: Energy Information Administration, Form 423, Department of Energy, 1979-1983.

deliveries from the various supplier to KP & L since 1981 and the associated delivered price.

According to their respective contracts, Pittsburg and Arch supplied the Lawrence and Tecumseh plants; Amax the Jeffrey station. In 1983 after the Pittsburg & Midway contract expired, only the Arch mines supplied Lawrence and Tecumseh. KP & L made up for the lost supply by using the plants less. The combined utilization rates at the Lawrence and Tecumseh plants for 1981, 1982 and 1983 were 38, 38 and 36 percent respectively.

Table 4.21

Quantity and Delivered Price of Coal Sold to Kansas Power and Light: 1981 - 1983

| Supplier | 1981 Quantity Delivered (MM TONS) | 1981 Average Price ($/MMBTU) | 1982 Quantity Delivered (MM TONS) | 1982 Average Price ($/MMBTU) | 1983 Quantity Delivered (MM TONS) | 1983 Average Price ($/MMBTU) |
|---|---|---|---|---|---|---|
| P & M | 0.272 | 1.79 | 0.006 | 1.91 | ---- | ---- |
| Amax | 4.772 | .98 | 5.072 | 1.16 | 5.761 | 1.20 |
| Arch | 1.195 | 1.85 | 1.191 | 2.09 | 0.988 | 2.14 |
| Total | 6.239 | | 6.269 | | 6.749 | |

Source: Energy Information Administration, Form 423, Department of Energy, 1981-1983.

After December 1984, when the Arch Minerals contract expires, KP & L has announced that Amax will be its sole supplier of coal. The original Amax contract was sufficient to supply four units at the Jeffrey station. Since the fourth Jeffrey unit has been postponed indefinitely, there is sufficient quantity under the contract to replace the coal supplied by Arch and Pittsburg. Unless load growth trends change drastically, causing a sudden need for the fourth Jeffrey unit, it is unlikely that Colorado producers will be able to reenter this market.

## Nebraska Public Power

Nebraska Public Power (NPP) is one of several public power districts in the state of Nebraska. Originally formed in 1939, NPP resulted from a merger of Consumers Public Power District, Loup River Public Power District, Platte Valley Public Power & Irrigations District. The present system has facilities located throughout the state. Major cities served by NPP include, North Platte, Grand Island, Norfolk and Hastings.

In 1981, retail sales amounted to approximately $94 million. Residential sales constituted approximately 36 percent of total sales, industrial 25 percent, and commercial customers about 27 percent.

In 1982 the NPP owned, operated or had operating control of one nuclear power plant, seven fossil fuel power plants, and eleven hydro plants. Three of the seven fossil fuel plants are coal fired: the

Sheldon (227 MW); the Gentleman (1278 MW); and the Krammer (135.5 MW). NPP has no plans to build additional capability before 1990.

Coal from several Colorado mines has been burned on a spot basis at the Kramer plant in every year since 1980 except 1981. Table 4.22 describes the quantity purchased and the supplying mines for each year since 1980. Five companies have supplied NPP with coal during the four year period, although the most any one mine delivered in one year was 85,000 tons. Northern Coal, which has not operated since early 1983, is the only company to deliver coal on a consistent basis.

Although the quantity was small, the Colorado mines listed in Table 4.22 supplied 100 percent of the coal burned at the Kramer plant in 1982 and 1983. Of the three NPP coal-fired plants, the Kramer plant is the least used plant in the system. In fact, with a 7 percent utilization rate, it is hardly used at all. The Gentleman plant, which is supplied under long term contract by ARCO mines in Wyoming, burns the bulk of the coal consumed by NPP and accordingly has the highest utilization rate, 44 percent in 1983.

The quantity of coal that can be sold in the future to NPP by Colorado producers depends on how much the Kramer facility is used. The Sheldon plant can only burn coals with a low ash fusion temperature which are not found in Colorado. Because of the contract with ARCO, which supplies all the coal needed to run the facility, and the cost differential, $.96 for ARCO compared to the $1.64 average for Colorado

Table 4.22

Purchases of Coal from Colorado
Mines by the Nebraska Public Power District
1980 - 1983
(MM TONS)

| Supplier | 1980 | 1981 | 1982 | 1983 |
|---|---|---|---|---|
| Northern | 0.006 | | 0.086 | 0.004 |
| Bear Coal | | | | 0.011 |
| Westmoreland | | | | 0.009 |
| Sunland | | | 0.010 | |
| Empire Energy | 0.002 | | | |
| Total | 0.008 | 0.000 | 0.096 | 0.024 |

Source: Energy Information Administration, Form 423, Department of Energy, 1980-1983.

mines, it appears that Colorado coal will not be burned at the Gentleman plant. If use of the Kramer plant increases, Colorado producers may be able to increase the quantity that they supply to NPP. However, based on purchasing practices since 1980, there is little reason to believe that it will be on anything but a spot basis.

## Fremont Department of Utilities

Fremont Department of Utilities (Fremont) is a small municipal utility serving Fremont, Nebraska. Located approximately 30 miles northwest of Omaha, Fremont had a 1980 population of about 24,000. The utility services only the town and surrounding area.

Three coal-fired units comprise the Fremont No. 2 power station. This is the only power plant owned or operated by Fremont. Total capacity of the station is 217 MW. Fremont is not building or planning to build additional capacity before 1990.

Colorado coal producers have had a relationship with Fremont either on a spot or short term (2-3 years) basis since 1980. Table 4.23 identifies the Colorado producers that have delivered coal to the utility in the last four years and the quantity that they sold. With the exception of the Kerr sales in 1980 and 1981, all of the sales shown were made on a spot basis. The Kerr contract ran from 1979 to 1981 and was not renewed.

Table 4.23

Sales of Colorado Coal
to the Fremont Department of Utilities:
1980 - 1983
(Million Tons)

| Supplier | 1980 | 1981 | 1982 | 1983 |
|---|---|---|---|---|
| Kerr Coal Co. | 0.095 | 0.030 | | |
| Colowyo | | | 0.002 | 0.002 |
| Empire Energy | | | 0.050 | ---- |
| P. & M. | | | 0.026 | ---- |
| Rock Castle | | | 0.002 | 0.015 |
| Sheridan Ent. | | | 0.051 | |
| Total | 0.095 | 0.030 | 0.131 | 0.017 |

Source: Energy Information Administration, Form 423, Department of Energy, 1980-1983.

After a year of exceptionally low demand, Colorado coal producers sold Fremont 131,000 tons in 1982. This amounted to approximately 76 percent of the coal purchased by the utility during the year. Table 4.24 shows the quantity of coal delivered to the plant annually since 1978.

Fremont paid an average of $2.02 per million Btu for the coal burned in 1982. During that year the D & RGW charged Unita Basin, CO producers approximately $24.30 per ton and Green River producers approximately $21.57. Assuming an average heat content of 10,700 Btu (the average burned at the plant during the year), these rates convert to $1.18 and $1.04 per million Btu respectively. Subtracting these tariffs from the $2.02 paid by Fremont during the year, Uinta Basin producers received $.84 per million Btu FOB mine for their coal and Green River producers $.98 per million.

Table 4.24

The Fremont Department of Utilities
1978 - 1982
(Million Tons)

| 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|
| 0.200 | 0.249 | 0.177 | 0.110 | 0.172 |

Source: Energy Information Administration, Form 423, U.S. Department of Energy 1978- 1982.

In November 1983, however, Bear Coal Co. of Colorado signed a five year contract with Fremont. The agreement calls for approximately 75,000 tons to be delivered annually to the plant. Based on the deliveries pattern depicted in Table 4.24, the Bear Coal contract will provide the bulk of Fremont's needs until it expires.

## Union Electric Company

Union Electric Co. (UEC) is a publicly owned utility servicing the southeastern corner of Iowa, the eastern half of Missouri and small territories in Illinois along the western border with Missouri. The service area includes St. Louis as well as 271 other communities. Approximately 2.5 million people live in the service area.

In 1982 the UEC had operating revenues of $1.112 billion. Commercial and industrial sales earned $621 million or about 56 percent of the total. Manufacturing industries make up the primary industries served by UEC. Residential sales amounted to $426 million in 1982 or 38 percent of the total. The balance of the utility's revenues came from sales for resale and street lighting (Moody's, 1983).

The UEC system consists of four coal fired plants: the Labadie, Sioux, Meramec and Rush Island; two oil and gas stations; two hydro stations; and one pumped-storage facility. The total capacity of the system is 6410 MW, with 80 percent or 5402 MW coal fired. Table 4.25 lists the various plants in the system, their net capability and fuel type. UEC is neither building new capacity nor planning to build new capacity before 1990.

In 1983 the UEC did not purchase coal from Colorado mines. This marked a change from their fuel supply practices since 1980. Between 1980 and 1982 UEC purchased coal from several mines in the state. In all

Table 4.26

Power Plants Comprising the
Union Electric System

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Meramec | 800.0 | Coal |
| Rush Island | 1,110.1 | Coal |
| Sioux | 997.6 | Coal |
| Labadie | 2,220.0 | Coal |
| Total Coal | 5,127,680 | |
| Venice | 500.0 | Oil/Gas |
| Ashley | 70.0 | Oil |
| Taum Sauk | 408.0 | Pumped-Storage |
| Keokuk | 128.0 | Hydro |
| Osage | 176.2 | Hydro |
| System Total | 6,409.9 | |

Source: Electric World, Directory of Electric Utilities, McGraw Hill, NY,NY 1982.

cases the coal was shipped to either the Labadie or Sioux plants and was purchased through the spot market. Table 4.26 describes the shipments from Colorado mines to UEC plants.

The coal supplied by Colorado producers constituted only a small percentage of the total quantity consumed at the Labadie plant. For example, Colorado mines supplied approximately 4 percent of the coal consumed at the Labadie plant in 1980, 10 percent of the total in 1981, and 3 percent in 1982. The deliveries to the Sioux plant in 1982 amounted to only 4 percent of the total delivered to the plant.

Table 4.26

Purchases of Colorado Coal
by Union Electric Co.: 1980 - 1983
(Million Tons)

| Plant | Mine | 1980 | 1981 | 1982 | 1983 |
|---|---|---|---|---|---|
| Labadie | Empire Energy | -- | 0.168 | 0.084 | -- |
| | W.R. Grace | 0.257 | 0.203 | 0.070 | -- |
| | Kerr Coal Co. | -- | 0.138 | --- | -- |
| Tot. Labadie | | 0.257 | 0.509 | 0.154 | -- |
| Sioux | Westmoreland | -- | -- | 0.098 | -- |
| Total | | 0.257 | 0.509 | 0.252 | 0.00 |

Source: Energy Information Administration, Form 423, U.S. Department of Energy, 1980 - 1983.

Whether or not Colorado producers will resume supplying coal to UEC is uncertain. UEC has approximately 65 percent of the coal requirements for the estimated remaining useful life of its coal-fired generating plants under contract. As of 1982, eighty-five percent of its current coal requirements were under long term contract (UEC, 1983). Based on this information and trends since 1980, any coal sold by Colorado producers to the UEC will be on a spot basis.

However, increased spot sales by Colorado producers are doubtful. Table 4.27 shows the various suppliers of coal to the Labadie plant in 1982, the quantity of coal they sold, the delivered price paid, and the average sulfur content. In 1982 the tariff charged by the D & RGW for a 500,000 ton or less shipment from the W.R. Grace mine was $24.96 per ton. The comparable tariff from the Empire mine was $25.21. The average Btu content of the coal shipped from the two mines was 10,000 for the W.R. Grace mine and 10,500 for Empire. Therefore, the dollar per million Btu equivalent tariffs for W.R. Grace was $1.24 per million Btu and for Empire energy $1.20 per million Btu. As Table 4.28 indicates, Inland Steel mines, which are located in Illinois, also provided UEC with low sulfur coal. To compete on a price basis with the Inland mines, Colorado producers would only have been able to charge $.33 to $.37 per million Btu FOB mine. Unless the UEC faces a significant increase in delivered prices from other eastern low sulfur producers, it is not likely that Colorado producers can sucessfully compete.

Table 4.27

Coal Suppliers for UEC in 1982

| Supplier | St. | Average Btu Content (Btu/lb) | Average Sulfur Content (%) | Delivered Price Content ($/MMBtu) |
|---|---|---|---|---|
| Consol | IL | 11,084 | 2.68 | 1.13 |
| Inland | IL | 11,300 | 0.87 | 1.57 |
| Amax | IL | 11,200 | 2.82 | 1.34 |
| Old Ben | IL | 11,850 | 1.20 | 1.84 |
| Freeman | IL | 11,800 | 1.30 | 1.72 |
| W.R. Grace | CO | 10,000 | 0.43 | 2.11 |
| Empire Energy | CO | 10,500 | 0.35 | 2.15 |

Source: Energy Information Administration, Form 423, U.S. Department of Energy, 1982.

## Mississippi Power

Mississippi Power (MP), a subsidiary of the Southern Company, services southeastern Mississippi. The service area comprises 23 counties and in 1980 had a population of about 818,000. In 1982 MP had approximately 138,000 residential and about 24,000 industrial customers. (Moody's, 1983).

In 1982, operating revenues totaled $358 million, with commericial and industrial customers accounting for $192 million or 53 percent of the total. Residential customers accounted for $90 million or 25 percent. (Moody's, 1983).

MP has three wholly owned fossil fuel fired power plants and part interest in two additional coal fired units. The Watson station, which is wholly owned, has gas, oil and coal fired units. In addition, MP has a 40 percent interest in the Green coal-fired plant in Alabama and a 50 percent interest in the Daniels plant in Mississippi, which it operates. Total coal fired capacity of the MP system is 1,450 MW or approximately 77 percent of the total. Table 4.28 identifies the power stations in the MP system, their capability and fuel type. MP is not planning to add capability to their system before 1990.

In 1978 MP contracted with General Exploration, which is now the Powderhorn Coal Company, to supply 800,000 tons of coal annually to the Daniels plant from their Roadside and Cameo mines in the Uinta Basin of

Colorado. The contract expires in 1995. Table 4.29 shows actual deliveries under the contract since 1979.

Table 4.28

Power Plants Comprising the Mississippi Power System

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Sweatt | 80.0 | Gas/Oil |
| Standard | 27.5 | Gas |
| Eaton | 67.5 | Oil |
| Watson | 1,012.0 | Gas/Coal |
| Green* | 200.0 | Coal |
| Daniel+ | 500.0 | Coal |
| Total | 1,887.0 | |

* Represents MP's 50 % interest in the plant. Gulf Power owns the other 50%.

\+ Represents MP's 40 % interest in the plant. Alabama Power owns the other 60%.

Source: Electric World, Directory of Electrical Utilities, McGraw Hill, NY,NY 1983.

Compared to the Watson plant, the Daniels plant burns lower sulfur higher cost coal. Table 4.30 shows the quantity of coal burned and the associated cost for each of the coal fired plants in the MP system for the period 1981 - 1983. Although there is a considerable difference between the fuel costs for the two plants, the two plants are used at approximately the same rate.

Table 4.29

Deliveries to the Daniels Power Plant
from the Roadside and Cameo Mines:
1979 - 1983
(Million Tons)

| 1979 | 1980 | 1981 | 1982 | 1983 |
|---|---|---|---|---|
| 0.657 | 0.754 | 0.756 | 0.804 | 0.729 |

Source: Energy Information Administration, Form 423, U.S. Department of Energy, 1979-1983.

Table 4.30

Delivered Quantity, Price and Utilization Rate
of Coal Burned at Mississippi Power Plants:
1981 - 1982

| | 1981 | | | | 1982 | | | |
|---|---|---|---|---|---|---|---|---|
| Plant | Quantity Delivered (MM Tons) | Aveage Price ($/MMBtu) | Util Rate (%) | Ave Sulf (%) | Quantity Delivered (MM TONS) | Average Price ($/MMBtu) | Util Rate (%) | Ave. Sulf (%) |
| Watson | 0.825 | 1.83 | 40 | 2.56 | 1.300 | 1.90 | 49 | 2.57 |
| Daniels | 1.340 | 2.69 | 40 | 0.57 | 1.620 | 2.96 | 46 | 0.57 |

Source: Energy Information Administration, Form 423, U.S. Department of Energy, 1981 - 1982.

Colorado producers cannot compete on a price basis with the Illinois, Alabama and Kentucky coals that supply the Watson station. Table 4.31 shows the quantity purchased and the associated delivered price paid for coal at the Watson plant. The 1983 tariff quoted by the D & RGW for shipment between 0 and 1,200,000 tons from the Powderhorn mines to the Daniels plant is $45.90. The average Btu content of Powderhorn coal shipped to the plant was 11,500. Based on the average heat content of coal shipped to the plant of 11,500, the dollar per million equivalent of the D & RGW tariff is $2.00. The tariff rate alone would preclude competition from Colorado producers for the Watson market.

Table 4.31

Quantity Delivered and Associated Price for Coal Shipped to the Watson Plant: 1983

| Company (St) | Delivered Quantity (mm tons) | Average Delivered Price ($/MMBtu) | Average Sulfur Content (%) |
|---|---|---|---|
| Unnamed | 0.112 | 1.86 | 2.58 |
| Coal Systems (AL) | 0.515 | 2.09 | 2.37 |
| Peabody (IL) | 0.111 | 1.79 | 2.96 |
| Pyro (KY) | 0.282 | 1.84 | 2.65 |
| Total | 1.020 | 1.96 | 2.53 |

Source: Energy Informatioin Administration, Form 423, U.S. Department of Energy, 1983.

As for the potential for Colorado producers to increase their shipments of low sulfur coal to the Daniels plant, the prospects are mixed. Table 4.32 compares the deliveries by Powderhorn Coal and the ARCO mines in Utah to their contracted obligations. The table shows that between the two contracts, MP has procurred about all the coal needed to burn the Daniels plant at the 43 percent level that they have averaged over the past three years. Should MP increase their utilization of the Daniels plant, and use low sulfur coal, then a new contract or spot opportunities may devleop.

Table 4.32

Comparison of Tonnage Delivered to
Tonnage Contracted for 1982 and 1983
for the Daniels Power Plant
(Tons)

| Supplier | 1982 Contracted | 1982 Delivered | 1983 Contracted | 1983 Delivered |
|---|---|---|---|---|
| Powderhorn | 800,000 | 804,000 | 800,000 | 729,310 |
| ARCO | 600,000 | 749,200 | 600,000 | 754,280 |
| Total | 1,400,000 | 1,553,200 | 1,400,000 | 1,483,590 |

Source: Coal Outlook, Guide to Coal Contracts, Pasha Publications, 1983.

## Central Power and Light Company

Central Power and Light Company, (CP & L) is a public utility servicing southern and southwestern Texas. A subsidiary of the Central and South West Corporation, CP & L serves an estimated population of 1,750,000 and 217 communities. Major cities served by CP & L include Corpus Cristi, Laredo, Harlingen, Del Rio, McAllen Victoria, and Kingsville.

Total operating revenues for the utility in 1982 were $899 million, 61 percent of which were industrial and commercial, 31 percent residential and rural, and 8 percent other. Most of the industrial activity in the CP & L service area is located in the Corpus Cristi area. Refining of oil and the production of chemicals, aluminum and cotton seed-oil are the principal industrial activities.

CP & L operates one coal fired plant, Coleto Creek, and twelve oil and gas fueled plants. Total capability of the CP & L system is 3523 MW, with 569 MW or 16 percent being coal-fired. A new 700 MW unit is expected to be on-line at the Coleto Creek station in 1988. Table 4.33 lists the power stations that comprise the CP & L system, their net capability and fuel type.

In 1976 CP & L and W.R. Grace entered into a fuel supply agreement that calls for 1.5 million tons of coal to be delivered annually to the Coleto Cr. plant. The contract runs until 2004. Table 4.34 shows the actual tonnage delivered since 1979.

Table 4.33

Power Plants Owned and Operated
by Central Power and Light

| Plant | Capability (MW) | Fuel Type |
|---|---|---|
| Coleto Creek | 600.4 | Coal |
| La Palma | 263.9 | Oil/Gas |
| Victoria | 553.5 | Gas |
| Nueces Bay | 531.0 | Gas |
| Lon C. Hill | 574.2 | Gas |
| Laredo | 187.0 | Gas |
| Bates | 188.7 | Gas |
| Es Joslin | 261.0 | Gas |
| Davis | 703.8 | Gas |
| Eagle Pass | 9.6 | Hydro |
| Total | 3,873.1 | |

Source: Electric World, Directory of Electric Utilities, McGraw Hill, New York, NY 1983.

Table 4.34

Deliveries to the Coleto Creek Power Plant
by W.R. Grace: 1979 - 1983
(Million Tons)

| 1979 | 1980 | 1981 | 1982 | 1983 |
|---|---|---|---|---|
| 0.033 | 0.982 | 1.776 | 2.036 | 1.697 |

Source: Electric World, Directory of Electric Utilities, McGraw Hill New York, NY, 1983.

Until 1983, W.R. Grace was the only provider of coal to CP & L. The contract described above was sufficient to provide 100 percent of the coal needed to the Coleto Creek station. In 1983, however, Cannelton Industries sold 15,000 tons of coal to CP & L from their mine in Kanawha county West Virginia.

Although the tonnage was small and was purchased through a spot market transaction, the event was significant for two reasons: first it shows that CP & L might look to other suppliers, rather than increase their purchases from W.R. Grace above the contract requirements. Second, the price paid for the Cannelton coal was $2.30 per million Btu, compared to $2.46 for coal from W.R. Grace. While the lower price will probably help to temper price escalations by W.R. Grace and the D & RGW, the railroad responsible for shipping the W.R. Grace coal, it probably is more significant as an indicator that price competition will result when bids go out for the new unit at Coleto Creek. Clearly low sulfur coal--the Cannelton coal is 0.65 percent sulfur-- can be supplied from West Virginia at a competitive price. This implies that producers in the low sulfur area of Kentucky, which is even closer to Coleto Creek, may also be serious competitors. W.R. Grace or other Colorado producers will not have a clear price advantage for the supply contract for the new unit.

## Conclusions

Several conclusions can be drawn concerning the non-Colorado utility market for Colorado coal. First, the market is predominantly contract oriented. In 1982, approximately 5.88 million tons of Colorado coal were sold to non-Colorado utilities. Ninety-two percent, or 5.40 million tons were sold under contract to six utilities: Illinois Power, Central Illinois Light Company, Northern Indiana Public Service Company, Mississippi Power, Iowa Electric Light and Power, and Central Power and Light. Spot sales during the year amounted to 485,000 tons and were made to three utilities: Union Electric, Nebraska Public Power District, and Fremont Utilities.

Second, there is a marked difference between the FOB mine price paid for contract and spot coal bought from Colorado producers. Table 4.35 compares the spot and contract average FOB mine prices paid in 1982. Contract prices ranged from \$0.96 per million Btu to \$1.82 per million Btu, while spot prices ranged from \$0.60 per million Btu to \$0.98 per million Btu.

Third, Colorado producers are only marginally competitive in the contract market. In 1983 the Central Illinois Light Company contract with West Slope Carbon was terminated for economic and quality reasons. Further, all six contracts were entered into prior to or during 1978.

Table 4.35

Comparison of Spot and Contract Prices
Paid by Non-Colorado Utilities
in 1982
($/MMBtu)

| Contract Type | Utility | FOB Mine | Rail Rate | Total |
|---|---|---|---|---|
| Contract | CP & L | $1.25 | $1.21 | $2.46 |
| | MP | 0.96 | 2.00 | 2.96 |
| | IELP | 1.82 | 1.42 | 3.24 |
| | NIPSCO | 1.67 | 1.21 | 2.88 |
| | CILCO | 1.19 | 1.19 | 2.38 |
| | IP | 1.10 | 1.31 | 2.41 |
| Spot | NPP | 0.60 | 1.15 | 1.75 |
| | Fremont-GR | 0.98 | 1.04 | 2.02 |
| | Fremont-U | 0.84 | 1.18 | 2.02 |
| | UEC | 0.91 | 1.22 | 2.13 |

Since 1979 only two contracts involving Colorado producers have been signed. One, a three year contract with Kansas Power and Light that was in effect between 1979 and 1982, and the other a five year contract between Fremont Department of Utilities and Bear Mining which was signed in 1983. Failure to sign more contracts during the last five years is a strong indication that Colorado producers are not being competitive. Certainly opportunities have been available.

Fourth, in 1985 there is a contract basis for delivery of about 4.6 million tons of Colorado coal to non-Colorado utilities. Table 4.36

shows the present contract obligations of Colorado producers to non-Colorado utilities. Unless the Illinois Power and Iowa Electric Light and Power contracts are renewed, after 1990 there is a contract basis of approximately 3.5 million tons.

Table 4.36

Contract Base of Colorado Producers to Non-Colorado Utilities (Million Tons)

| Utility | 1985 | 1990 |
|---|---|---|
| IP | 0.830 | |
| NIPSCO | 1.250 | 1.250 |
| IELP | 0.250 | |
| MP | 0.800 | 0.800 |
| CP & L | 1.500 | 1.500 |
| Total | 4.630 | 3.550 |

Fifth, with the exception of the Iowa Electric Light all the non-Colorado plants burning Colorado coal have air emmission standards that require the burning of low sulfur coal. In fact, deliveries to the Illinois Power, Central Illinois Light Company, Northern Indiana Public Service Company and Mississippi Power are consumed exclusively at plants that burn low sulfur coal. These stations typically have the highest fuel costs in each utility's system. In each case the plants burning low sulfur coal have the lowest utilization rates amoung each utility's coal fired plants.

Sixth, the combined market size for utilities buring Colorado coal under contract will expand. Northern Indiana Public Service Company is planning a new 344 MW unit at the Schahfer plant, and Central Power and Light is planning to build a new 700 MW unit at the Coleto Creek facility. These plants, once on-line, represent a potential for Colorado mines to sell and additional 2.5 million tons more annually.

Seventh, Colorado producers face intense price competition from Wyoming, Illinois and Kentucky mines that can produce a competitive quality low sulfur coal. Delivered prices in 1983 show that in all but the Illinois Power market the Colorado producer is the highest priced supplier of coal.

Eighth, the spot market between 1980 and 1982 amounted to 447,000, 583,000 tons, and 479,000 tons. The average during the period was 503,000 tons. Whether this average is maintained is uncertain. In 1983, the Union Electric Company, which bought 252,000 tons in 1982 did not purchase coal from Colorado producers. In section 4.6 it was shown that Colorado producers are no longer price competitive in this market. In addition, the contract between the Fremont Dept. of Utilities and Bear Mining will reduce their spot purchases by approximately 75,000 tons annually until 1989, the expiration date of the contract. Combined, these two events suggest that spot sales will be in the neighborhood of

250,000 tons unless new customers can be found.

Finally, none of the utilities that have bought Colorado coal on a spot basis since 1980 are expecting to add coal fired capacity to their systems. This suggests that Colorado producers will have to find new utility customers if they wish to increase their spot business substantially.

# Chapter 5

## Conclusions

The objective of this study was to determine whether the coal production decline in Colorado since 1982 reflects general market conditions or whether it is reflective of a deterioration of Colorado's competitive position in the national market. The answer, not surprisingly, is a little of both. Deliveries to individual utilities such as Illinois Power and Mississippi Power have been reduced deliveries due to lower demand for the electrical power that their plants produce. Coal sales losses due to reduced electrical demand, however, were minimal.

At the same time Colorado producers have experienced a marked deterioration in their competitive position relative to coal producers in other parts of the country, particularly Wyoming and Kentucky. There are several indicators. First, as of December, 1983 there were six utilities located outside of Colorado that have long term contracts with Colorado producers. Of the six, only one of the contracts was signed after 1978. That contract, between Fremont Dept. of Utilities and Bear Mining, was a five year contract for about 75,000 tons annually. No other utility contract with a life greater than two years has been signed.

Second, Colorado coal has become too expensive to compete with mines in Wyoming and Central Appalachia that produce a similar product.

Colorado producers lost one long term contract to Central Light and Power in 1982 for economic reasons. In the cases of CP & L, NIPSCO, and IELP, the Colorado producer is either the most expensive supplier or close to it. Even Colorado Front Range utilities can and are purchasing coal produced and transported from Wyoming mines at prices that are as much as 33 percent of the delivered price of coal purchased from Colorado producers.

Will the deterioration continue? The evidence does not lend itself to optimism, at least until after 1990. The principal utility market for Colorado coal is in Colorado. As was said above, Colorado coal is not price competitive at the present time to the utilities with plants along the Front Range, yet the Front Range is the area where the greatest growth in electrical demand thus coal is projected. Unless oil shale or some other major force for economic development occurs on the Western Slope, electrical demand will grow slowly--too slowly to offer much hope for greatly expanding coal sales.

Non-Colorado utility markets will grow between now and 1990. Two of the utilities that are presently customers of Colorado producers have plant expansion programs underway. They offer the prospect of 2.5 million tons of additional demand by the year 1990, if Colorado producers can deliver at a competitive price.

There are other issues that may effect the market for coal, particularly in states other than Colorado. Principal among them are the marketing successes of the various mine development projects in Colombia and other export activities of the Poles and South Africans. Producers from these regions are presently marketing their products to utilities along the Gulf and Atlantic coasts. Florida Power, for example, recently signed a contract with a Colombian producer for 600,000 tons annually. Similar efforts by the Poles landed a 100,000 ton sale with Tampa Electric Co. (Coal Age, 1984).

Kentucky and West Virginia producers are currently the principal suppliers to the Atlantic and Gulf utiilities, particularly for low sulfur coals. Should their market be constricted due to foreign competition, they will be forced to devote more attention to the Illinois and Indiana markets, which could heighten competition further. As has been shown they can be very competitive and cause substantial problems for the Colorado producers.

The prospect of tighter sulfur emmission regulations is another big issue for Colorado producers. Some think that tough acid rain legislation would stimulate the demand for low sulfur coals to the benefit of Colorado producers. This argument is based on the experience in early and mid 1970s when air quality legislation, which first limited sulfur emmissions, was passed. At that time, Colorado producers were able to immediately supply the sudden demand for low sulfur coal. The Powder River basin was only beginning to be developed and the low sulfur Eastern producers had strong export markets for their coal. Five of the six long term contracts presently held by Colorado producers were signed in this competitive climate.

While a repeat of this experience is possible, the evidence presented in the Illinois Power, Central Light and Power and Northern Indiana Public Service Co. case studies suggests a different outcome. Wyoming and Kentucky low sulfur producers currently supply low sulfur coal to four of the five non Colorado utilities served by Colorado mines at lower prices. Already strong price competition exists.

In addition, there is enormous overcapacity existing in the Powder River region, which can be brought on-line at what amounts to marginal costs. Colorado producers will have a difficult time competing against Powder River Basin suppliers selling on the margin. To make matters worse, because of the lower than expected electricity demand many midwestern utilities may decide that the Powder River coal is sufficiently less expensive to derate their boilers to burn the lower BTU coal. They simply do not need the additional capacity afforded by burning the high BTU Colorado coals.

What then can be done to stimulate the future of the Colorado coal industry? In the short term, the next 5 to ten years, probably not much. The delivered price of Colorado coal on a dollar per million BTU basis must drop before Colorado producers will be widely competitive in the market place. Railroads must find ways to deliver coal at lower costs and producers must improve their production methods to achieve similar objectives. Both groups claim that all that can be done is being done.

On a longer time horizon there are opportunities. Different transportation technologies, such as the proposed CO2 pipeline proposed by Perma Resources and Southwest Public Service Co, offer hope for improved transportation competition and thus pricing (Coal Age, 1984). On the producer side, perhaps new technologies such as robotics and improved beneficiation techniques can be developed to reduce mining costs or increase the Btu value of the coal. Government, through the granting of incentive tax credits for utilization of innovative technologies and educational institution support could be a principal motivator of such research and development.

## Areas for Further Research

This study, like most studies of its type, raised more questions than it answered. Perhaps the most serious questions concern determining who are the major competitors for the supply of low sulfur coal to the midwest and southern markets. Are they limited to Wyoming and Kentucky or should the low sulfur mines in West Virginia and Illinois also be considered? What is the reserve base of these competitors? What are their transportation options? Most importantly, what are their operating costs, how much production can they add on the margin and how much must they capitalize?

A second area for additional study concerns demand from utilities other than those included in this study. What other utilities in Illinois, Indiana, Iowa, Texas or Mississippi burn or plan to burn low sulfur coal? Do they have plans for adding new capacity? Do they purchase low sulfur coal through the spot market? Are their boilers designed to burn Colorado coals?

Finally are there public policy actions that could be taken to improve the marketability of Colorado coal? Some states, Ohio and Alabama for example, make it difficult for their utilities to burn coal from other states. Colorado may want to consider a policy that would require or provide incentives to Colorado utilities to encourage the consumption of Colorado coal. It should be recognized, however, that such a policy would probably lead to higher fuel costs to utilities; thus, higher bills to consumers.

Also, the state should consider supporting acid rain legislation. Much of the debate to date has centered on the funding mechanism for the cleanup. Further tightening of sulfur emmission standards might lead to a higher demand for Colorado coal. The economic benefits to the state from increased production might offset the clean up costs.

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