An Assessment of Development and Production Potential of Federal Coal Leases

December 1981

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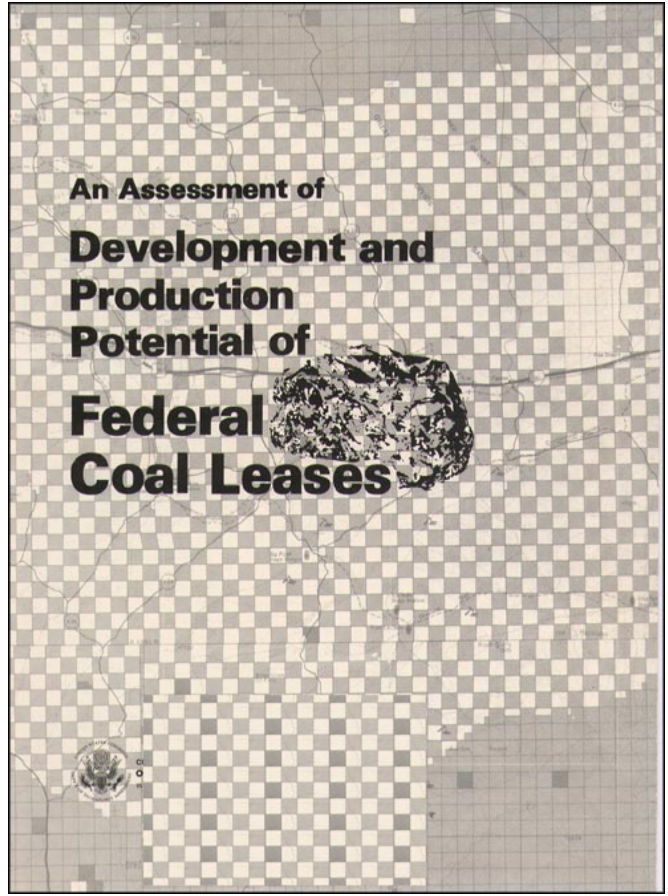

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Foreword

This report is submitted in fulfillment of OTA's mandate under the Federal Coal Leasing Amendments Act of 1976 (Public Law 94-377) "to conduct a complete study of coal leases entered into by the United States under section 2 of the act of February 25, 1920 (commonly known as the Mineral Lands Leasing Act). "

The act directed that the study "shall include an analysis of all mining activities, present and potential value of said coal leases, receipts of the Federal Government from said leases, and recommendations as to the feasibility of the use of deep mining technology in said leased area. " "Present and potential value" have been defined as the amount of potential coal production from Federal leases in the next decade.

This study differs from the typical OTA assessment in that the report "assesses" resources instead of technology. The main focus of the study is an estimation of the likely production from the existing 548 Federal coal leases in the seven major Western coal States. Although technical factors, mostly of a geological and mining engineering nature, were important in arriving at these estimates, the evaluation of technology was not central to the work.

OTA's analysis was greatly aided by the five State task forces held by OTA in Colorado, New Mexico, Oklahoma, Utah, and Wyoming. The task forces, composed of participants from State governments, local and Federal agencies, industry, citizens groups, and local universities were of inestimable help to OTA in evaluating the development potential of undeveloped leases and in providing insights on the factors affecting coal development in these regions,

The estimates of potential production from Federal leases made in this report are not forecasts of the coal that would be produced at a given price or a given demand. They are estimates of the total amount of coal that could be produced from existing and planned Federal mines and from those undeveloped Federal leases that have mining costs competitive with costs at currently operating mines in the same area. If the demand for Federal coal does not increase to these levels of potential production, then not all the Federal leases that could technically and economically be developed will be mined.

We hope that this report will provide Congress with helpful insights for the impending debates on Federal coal leasing and coal use goals for the United States.

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Contents

CHAPTER 1

Executive Summary

Contents

List of Tables

List of Figures

Executive Summary

Overview

As of late **1980**, there were 565 Federal coal leases* in existence in 14 States covering 812,000 acres and containing 16.5 billion tons of recoverable reserves. This study examines the development potential and production prospects for the 548 Federal coal leases in the seven States of Wyoming, Montana, Colorado, Utah, New Mexico, North Dakota, and Oklahoma, with principal emphasis on the 502 leases in the first six States listed above: the six major Western Federal coal States. These six States contain over 98 percent of leased Federal reserves and account for over 99 percent of Federal coal production. The 17 small leases in Alabama, Alaska, California, Kentucky, Oregon, Pennsylvania, and Washington, with 0.5 percent of leased Federal coal reserves and 0.2 percent of Federal coal production, were not examined in this study. Furthermore, the development potential and production prospects of currently unleased Federal coal were not examined in this study. Therefore, the findings of this study on potential Federal coal production and its relation to likely markets for Federal coal refer only to currently leased Federal coal in the seven States of Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming.

A Federal coal lease may be conveniently classified by its mine plan status: in an approved mine plan, or in a mine plan submitted to and pending approval by the U.S. Department of the Interior (DOI), or with no mine plan. The 565 Federal coal leases are grouped as follows:

1. There are 198 leases in approved mine plans covering nearly 280,000 acres, and containing 7.4 billion tons of recoverable reserves.

   Of these 198 leases, 182 are located in the six major Western Federal coal States listed above. The 182 leases are included in 69 approved mine plans. Of these 69 Federal mines, 64 produced coal in 1979; the remaining 5 are scheduled to begin production within a few years.

   Total coal production from these 64 Federal mines in 1979 was 138 million tons. The Federal portion of this production was 60 million tons, up from 7.3 million tons in 1970.** In 1979, Federal production in the six States of Wyoming, Montana, Colorado, Utah, New Mexico, and North Dakota accounted for 7.7 percent of the total U.S. coal production of 776 million tons, In 1980, Federal coal production in these six States grew to 69 million tons, or 8.4 percent of the total U.S. coal production of 820 million tons.
2. There are 118 leases in 32 pending mine plans covering nearly 195,000 acres and containing 2,5 billion tons of recoverable reserves.
3. There are 249 leases not in mine plans covering nearly 338,000 acres and containing 6.6 billion tons of recoverable reserves. (These leases are called undeveloped leases in this report.) However, many of these leases are in the process of being developed and could be in production within the decade.

*The leases sold in early 1981 under the new Federal coal management program are not included in this total and were not considered in this study.

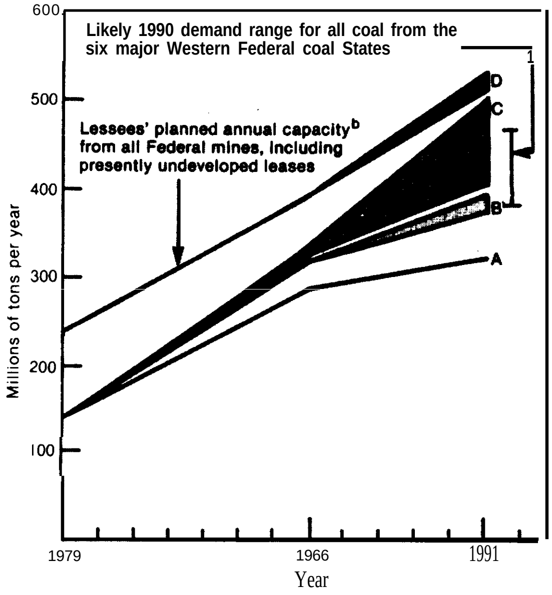
**Coal from Federal coal leases is referred to as Federal coal. A mine that includes a Federal lease is called a Federal mine. Sometimes, for the sake of efficiency of recovery or economy of operations, intervening State or private coal is mined with Federal lease(s) in the same mine. This practice is the rule in southern Wyoming and North Dakota, for example. Thus, many Federal mines produce both Federal and non-Federal coal. A mine that contains no Federal coal is called a non-Federal mine. Total coal production in a State or region is thus the sum of: 1) Federal coal production from Federal mines plus 2] non-Federal coal production from Federal mines plus 3) non-Federal coal product ion from non-Federal mines.

Approximately 5 percent of currently leased Federal reserves appear undevelopable because of poor property characteristics, remote location, or environmental prohibition. Considerable uncertainty surrounds the likelihood of the development of another 15 to 20 percent of leased Federal reserves (some of them in the pending mine plan category) because of factors such as construction of transportation systems, synfuels development, pace of associated powerplant construction, availability of additional Federal reserves, and lessee development priorities. Delays in development and production caused by these factors and by market uncertainties might result in leases containing over 7 billion tons of reserves, or 43 percent of all currently leased reserves, to fail to meet diligent development requirements by 1991; leases containing over 3.5 billion tons of recoverable coal are unlikely to meet diligence by 1991; leases containing approximately 3.4 billion tons of recoverable reserves have uncertainties surrounding attainment of diligence by 1991.

The following estimates of potential production from Federal leases are not forecasts of the coal that will be produced at a given price or a given demand. They are estimates of the total amount of coal that could be produced from operating Federal mines and from those Federal leases that have characteristics comparable to operating mines in the same region. Coal from these leases would thus be likely to have mining costs competitive with costs at currently operating mines in the same area. If the demand for Federal coal does not increase to these levels of potential production, then not all the Federal leases that could technically and economically be developed will go into production.

Production from existing Federal coal leases is likely to increase substantially over the next 10 years. Planned production capacity for 1986 for Federal mines is 400 million tons per year; for 1991, over 535 million tons per year (see fig. 1). OTA estimates that production from Federal mines could range between 410 million and 500 million tons per year in 1991 depending on markets, synfuels development, and rail construction. Actual production in 1991 could fall below this range, however, because of competition with non-Federal mines and new Federal coal leases in the West and from other coal-pro-

Figure 1.— Potential Production From and Planned 'Capacity of Federal Mines Summed Over the Six Major Federal Coal States[a]



Potential annual production, [b]

A: Lessees' planned annual production from Federal mines in currently approved mine plans only

B: Lessees' planned annual production from Federal mines in currently approved and pending mine plans

C: The sum of B, above, **plus estimates** of **potential** production from presently undeveloped Federal leases

[a] Wyoming, Montana. Colorado, Utah. New Mexico and North Dakota

[b] **Planned capacity for a given year is the upper** limit to potential production in **that year (although an even higher total capacity might be attainable in a very** strong market for coal) In many cases (e.g., currently approved mines m the Powder River Basin in 1991), the lessees' production plans call for them to produce at or **near capacity. In other cases, even optimistic production plans fall short of using planned capacity to the full. Some mines, particularly newer mines in the Southern Rockies will not attain their planned maximum capacity until the 1990's. In all cases, however, the capacities planned for 1986 or 1991 were used in deriving fig. 1, above, not the higher numbers for planned maximum capacities in the post 1991 period For most Federal mines in the Southern Rockies, the planned productions for 1986 and 1991 are close to the planned capacities for those years**

Explanation of ranges

C: 92 million tons per year range in 1991
65 mty = Dominant uncertainty is the development of markets for the coal
22 mty = Dominant uncertainty is the construction of two railroads, one to the Kaiparowits Plateau in Utah (14 mty) and one to the Star Lake. Bisti area of New Mexico (8 mty)
5 mty = Dominant uncertainty is the schedule of synfuels development
D 22 million ton per year range in 1991
Dominant uncertainty is the construction of the two railroads mentioned above, under C

SOURCE Office of Technology Assessment

ducing regions of the country and because overall demand for coal may not grow sufficiently during the next decade to support this level of production from Federal mines.

During the 1990's, demand for coal in general and Western and Federal coal in particular may grow rapidly, particularly if coal-based synfuels and exports of Western coal to foreign countries become important.

The Powder River basin of Wyoming and Montana was the source of about 50 percent of coal produced from Federal mines in 1979 (71.7 million tons) and contains 56 percent of recoverable Federal coal reserves under lease (9.2 billion tons). In 1979, there was more than 75 million tons of overcapacity in Federal mines in the Powder River basin. The Powder River basin can increase production substantially by 1990. For 1990, 186 million tons of Powder River basin coal have already been contracted: 159 million tons from currently operating Federal mines, 17 million tons from undeveloped Federal leases, and 10 million tons from currently operating non-Federal mines. Planned capacity for 1990 for all coal properties in the Powder River basin likely to be in production by that year is approximately 350 million tons per year. The likely demand range for Powder River basin coal for 1990 falls substantially below this planned mine capacity.

The States of Colorado, New Mexico, and Utah contain 360 Federal coal leases, about a third of which (113 leases) are in active mines, The five major coal-producing regions in these three States have a wide range of coal quality and mining conditions, The area contains both large and small active surface and underground mines.

In 1979, mines with Federal leases in Colorado, New Mexico, and Utah produced 35 million tons of coal, Little overcapacity in coal production existed in these three States in 1979, New mine plan proposals have been submitted for another 108 Federal leases and 96 out of the 139 leases that are not in mine plans might be developed over the next decade. By 1991, Federal mines in these three States could sustain 110 million to 146 million tons per year of production, 65 million tons per year from currently operating Federal mines, 28 million to 49 million tons per year from new Federal mines with plans are pending approval and 17 million to 32 million tons per year from presently undeveloped leases. These estimates are subject to two principal uncertainties: 1) whether demand for coal from this region will increase as generally expected; and 2) whether proposed coal transportation systems will be constructed to connect currently inactive coal mining areas in southwestern Utah and the San Juan basin of New Mexico with potential markets. At present, only the proposed Star Lake Railroad in the San Juan basin is nearing approval. However, the above numbers suggest that there will be little overcapacity in coal production in this three-State region over the next decade.

The potential for continued overcapacity in the Powder River basin over the next 10 years has caused questions to be raised about the timing, extent, and location of large-scale leasing under the new Federal coal management program. The debate focuses on the role of competition and the free market in resource supply, the potential costs to the social and physical environments of the coal-producing areas of "overleaping," the length of time needed to bring a new lease into full scale production, the margin of supply safety needed for prudent planning on a national and a corporate level, questions of equity raised by restricted opportunities for new entrants to Federal leaseholding, a fair return to the public for the use of its resources, and the levels of demand likely in the early to mid-1990's. Many proponents of large-scale new leasing in the Powder River basin in the near future cite the long moratorium on such leasing and its effect of restricting entry possibilities to leaseholding as one reason for prompt resumption. They also contend that postponing leasing will unduly interfere with the workings of the free market and will restrict competitition. They anticipate high demand for coal by 1995 and fear that the present leased reserve base in the Powder River basin will not provide enough certainty or flexibility to meet that demand efficiently. Opponents of large-scale new leasing in the Powder River basin as scheduled in 1982 cite the potential for overcapacity through the early 1990's as proof that such leasing is not necessary at this time. They contend that leasing can be safely deferred until its necessity is clearly indicated by realistic demand forecasts. They hold that large-scale leasing substantially beyond that necessary to meet likely demand in 1990 will place an unnecessary strain on orderly planning in the communities of the region, shift demand to the Powder River basin that could have been met by Midwestern supply, depress the value of leases so that the public will not receive a fair return for its resources, and, moreover, be unlikely to increase competition significantly.

Minability of Federal coal reserves in the West is affected by administrative and regulatory decisions in several aspects of environmental concern. These areas of concern include air quality, water resources, alluvial valley floors, return to approximate original contour, and wildlife resources. The effect of environmental regulations on the production of Federal coal has been to remove small amounts of minable coal from the recoverable reserve base, to delay development of other recoverable reserves, to increase the complexity of the mine permit process, and to increase the overall cost of mining.

The percentage of recoverable Federal reserves currently under lease on which mining could be prohibited or delayed over the next 10 years because of environmental regulations is between 5 percent and 10 percent of the total currently leased reserves, Less than 1 percent of currently leased Federal reserves appear likely to be subject to complete prohibition from mining; the remainder of currently leased Federal reserves that may be affected may be subject to delay in mining because of unresolved environmental questions, but the available evidence indicates that most of these reserves will be mined. There are additional leased reserves (mainly in the Kaiparowits Plateau in southern Utah) over which there are potential environmental conflicts, but impediments to development of these reserves are primarily related to nonenvironmental factors such as transportation availability y.

Status of Federal Coal Leases

In terms of tonnage, a little over one-half of the U.S. recoverable coal reserves lies west of the Mississippi River; in terms of heat content, a little less than one-half lies west of the Mississippi River. According to the best available data, the Federal Government owns between 50 and 60 percent of the coal reserves in the six major Federal coal States;* the percentage varies considerably among coal regions.

Since 1920, DOI has leased rights to mine Federal coal to the private sector. During the past 60 years, over 16 billion tons of coal on 812,000 acres have been leased and remain in currently existing leases. Less than 20 percent of the total coal reserves owned by the Federal Government are presently under lease.

A lease is necessary to mine Federal coal. The lease grants the lessee exclusive rights to mine coal subject to stipulations in the lease established by DOI and subject to Federal and State laws. Historically, most leases have been issued in two ways: 1) competitively through bidding at lease sales, and 2) noncompetitively through an application process called preference right leasing. **About half of all existing leases have been issued by

*The six major Federal coal States are Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming.

**About 6 percent of existing leases have been created in a third way, segregation or partial assignment, whereby a lease tract is split into two or more units. A new lease(s) is issued for the new unit(s) and the acreage of the original lease is correspondingly reduced.

each method, but the Federal Coal Leasing Amendments Act of 1976 abolished the preference right system and required competitive leasing of all Federal coal. As of January 1, 1980, 176 preference right lease applications (PRLAs) covering nearly 404,000 acres and containing 5.8 billion tons of recoverable reserves were in existence, All these applications are scheduled to be processed by DOI by 1984,

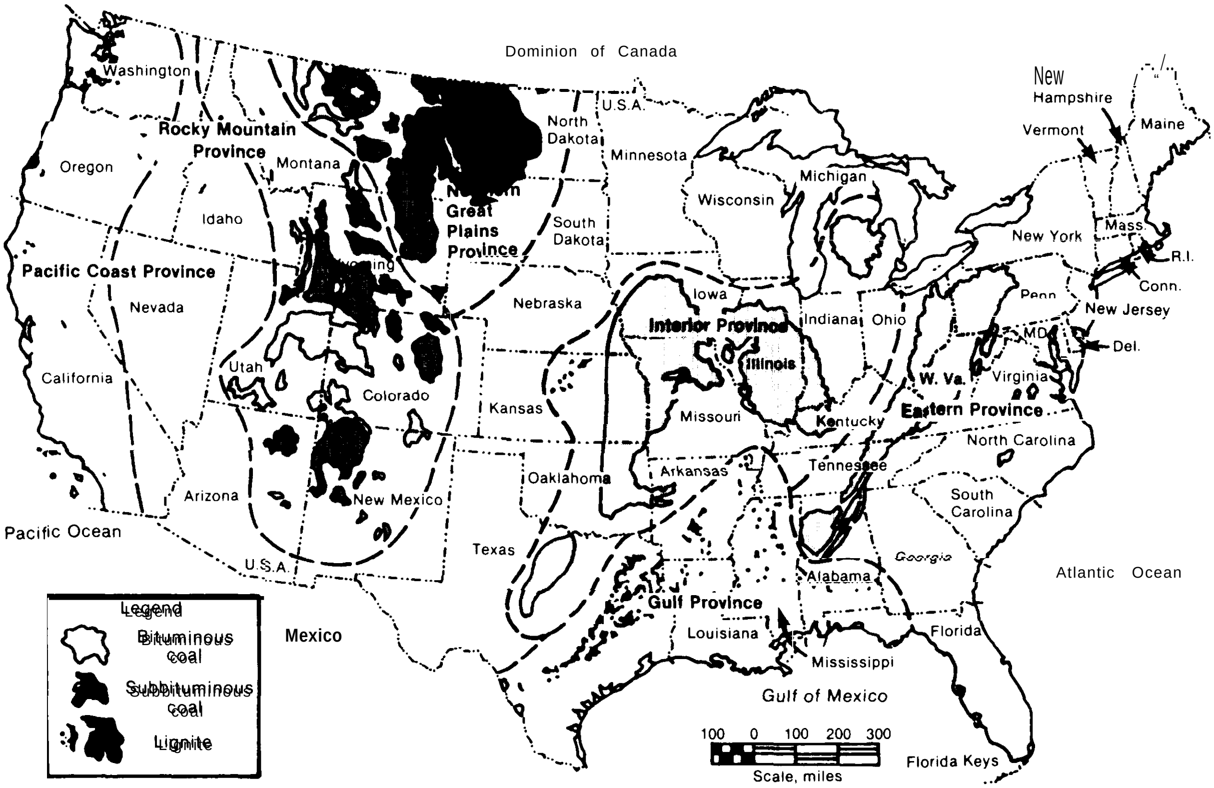
DOI began issuing leases under the new coal management program in January 1981, after a lo-year moratorium on all but leasing for special purposes. * Given the 5- to 12-year leadtime required to develop a coal mine, production from presently unleased land will be relatively small during most of the 1980's.

*Those leases issued under the new Federal coal management program are not included in this report.

Federal Coal Resources and Production

The Federal Government owns coal resources in all the major coal regions of the United States. However, the vast majority of Federal coal is located in two coal regions in the Northern Great Plains coal province and seven regions in the Rocky Mountain coal province. Federal leases in these two provinces include over 98 percent of the 16.5 billion tons of recoverable coal currently under lease. Three-quarters of the Federal coal reserves on leases outside of the Northern Great Plains and Rocky Mountain coal provinces are contained in 46 leases in Oklahoma, which is geologically part of the Interior coal province, The remaining reserves (0.5 percent of the total under lease) are in 17 leases in the States of Alaska, Alabama, California, Kentucky, Oregon, Pennsylvania, and Washington (see figs. 2 and 3).

Figure 2.—Generalized Coal Provinces of the United States



SOURCE: U.S. Bureau of Mines, adapted from USGS Coal Map of the United States, 1960

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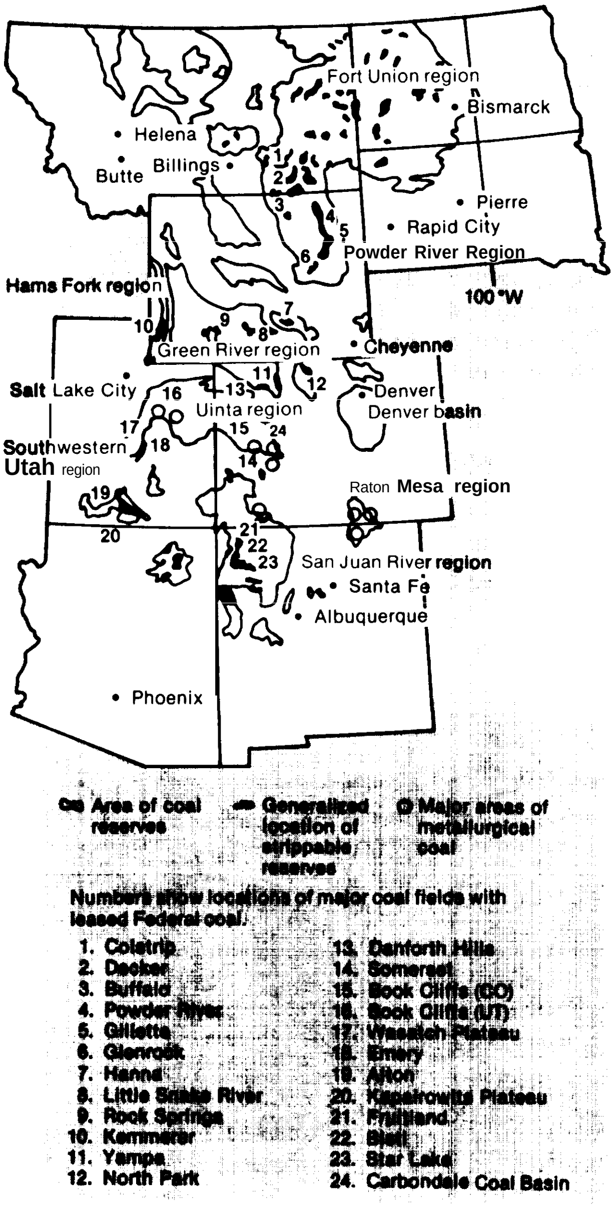
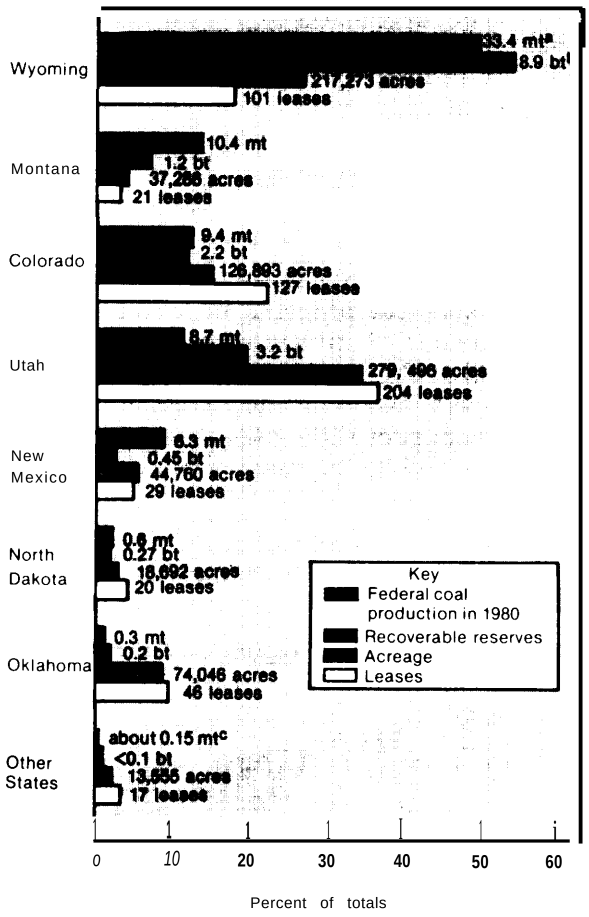
Figure 3.—Sketch Map Showing Major Coal Regions With Leased Federal Coal, and Generalized Location of Strippable and Metallurgical Coal Deposits



SOURCE Base Map National Academy of Sciences, *Rehabilitation Potential of Western Coal Lands,* Cambridge, Mass, Ballinger Press, 1974)

Figure 4.— Distribution of Production, Reserves. Acres, and Number of Leases by State ‘



Totals

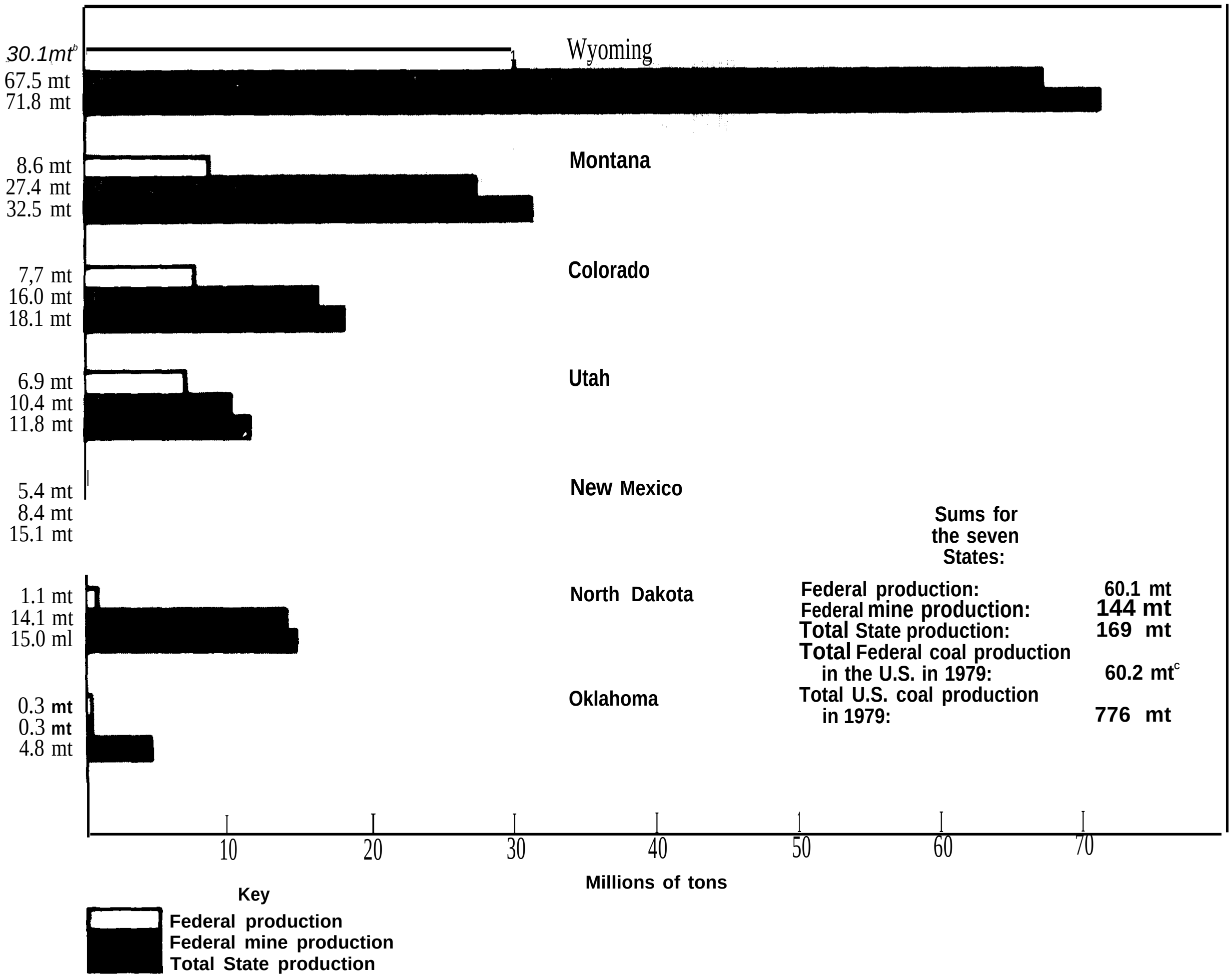
69.2	million tons (mt) of Federal coal production in 1980
16.5	billion tons (bt) of recoverable coal reserves under Federal coal lease
812,001	acres under Federal coal lease
565	Federal coal leases

[a] mt million tons
[b] bt billion tons
[c] 0.14 million tons in 1979

SOURCE Off Ice of Technology Assessment

Figure 4 summarizes 1980 Federal coal production and the distribution of leases, leased acreage, and leased recoverable reserves among the Federal coal States. Figure 5 summarizes 1979 Federal production, Federal mine production, and total production by State for those seven States. The States of Wyoming and Montana together contain 61 percent of leased reserves and accounted for 63 percent of Federal production in 1980.

Figure 5.— Distribution of Federal Production, Federal Mine Production and Total State Production in 1979, by State, for the Seven Federal Coal States Considered in This Report[a]



[a]See the footnote on page 8 for definitons of Federal production, Federal mine production, and total production
[b]mt = milion tons
[c]The other States contributed 0.14 mt of Federal production in 1979

SOURCE Office of Technology Assessment

Most of this came from the large surface mines in the Powder River basin. Colorado and Utah, which have 59 percent of leases, contain 33 percent of recoverable reserves and produced 26 percent of Federal coal in 1980. Mines are smaller on the average in these two States than in the Powder River basin and underground mining currently accounts for about 40 percent of production. New Mexico and North Dakota contain predominantly large surface mines; coal properties in North Dakota have relatively small amounts of Federal reserves in conjunction with large amounts of private coal.

Heat content of Colorado and Utah coal is generally higher than that of the Powder River basin; leased New Mexico coal is generally of higher heat content than Powder River basin coal, but lower than Colorado and Utah coals. Utah, Colorado, New Mexico, and Oklahoma all contain metallurgical grade coal under lease, North Dakota coal is all lignite of low heat content and in general is suitable only for onsite use.

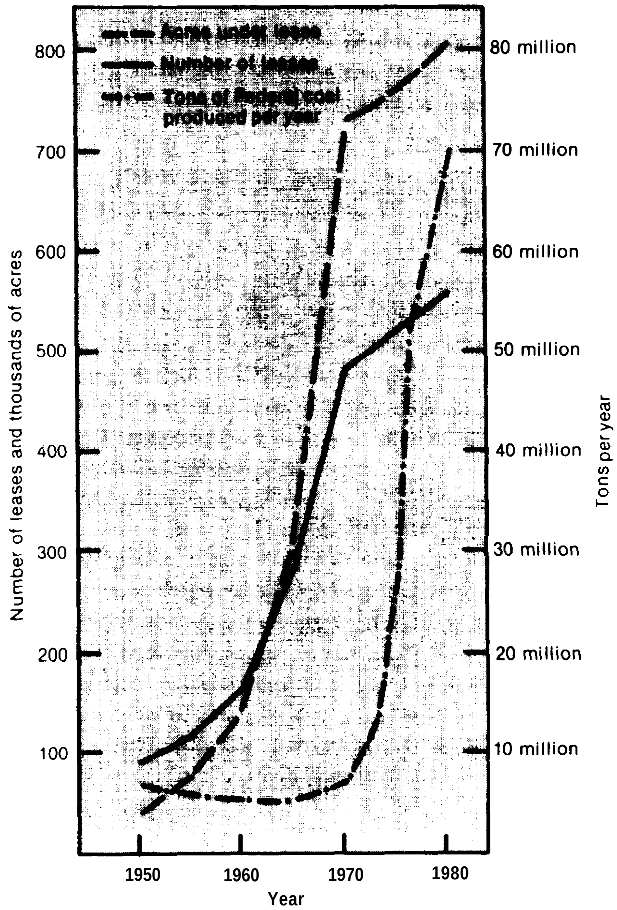
The quality of coal reserves presently under lease and PRLA does not appear to impose any serious limitations for meeting the demand that is likely for Western coal over the next 10 to 15 years. Most leased reserves have low-sulfur and ash content and are suitable for use by utilities, which constitute the single largest user of Western coal.

Because of low heat content, the coal on all Federal leases in the Fort Union region of North Dakota and Montana and about 50 million tons of potential annual production capacity from Federal reserves under lease and PRLA in the Wyoming Powder River basin* are probably suitable only for onsite development for electric power or synfuel plants. (The large majority of leased Federal reserves are, however, of sufficiently high quality to be exported out of the producing State.) Deposits of metallurgical-grade coal are relatively limited in the West, but demand for Western metallurgical coal is also limited; the availability of Federal and non-Federal Western metallurgical coal is probably sufficient to meet the limited demand for this coal anticipated in the foreseeable future.

Federal coal production has risen steadily over the past 10 years. Figure 6 shows the change since 1950 in the number of leases, the acreage under lease, and Federal coal production. Whereas the sharp rise in leasing occurred in the 1960's, the sharp rise in production from leased land started 10 years later, in the 1970's. Figure 7 compares Federal coal production and total coal production in the six major Federal coal producing States. Production from leased land started its sharp rise approximately 5 years later than overall Western production and has risen faster in most years since then. During the next decade, coal production from Federal leases will probably increase at a faster rate than non-Federal coal production in the West because of the large increases in Federal production expected in the Powder River basin.

*Forty-five million tons out of the 50 million tons are unlikely to be in production by 1991 but could come into production in the 1990'5.

Figure 6.—Number of Leases, Acreage Under Lease, and Federal Coal Production From 1950 to 1980



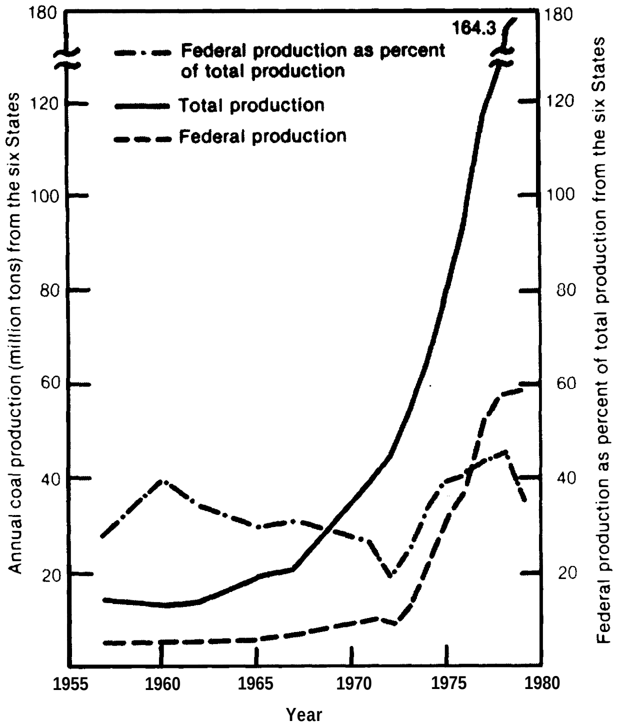
SOURCE Acreage and number of leases data from Office of Technology Assessment review of U S Department of Interior case files Federal coal production from the U S Department of the Interior, *Federal Coal* Management *Report, F/sea/ Year 1978,* March 1979 and from the ACLDS.

Ownership of Federal Coal Leases

The ownership of Federal coal leases has undergone marked changes over the last 30 years. Figure 8 shows how the leaseholdings of 11 groups of lessees and two major leaseholding companies have changed since 1950.

Independent coal companies and unincorporated individuals dominated coal leasing in the 1950's and 1960's, but their relative importance has steadily declined since 1950. In contrast, the electric utilities, major energy companies, and natural gas pipeline companies have increased their Federal coal hold-

Figure 7.—Annual Coal Production From the Six Major Federal Coal-Producing States in the West, 1957-79[a]



[a]The six states are Colorado, Montana, New Mexico, North Dakota, Utah. and Wyoming

SOURCES Data for 1957-77 from table 27 U S Department of Interior *Final Environmental States Federal Coal Management Program* (Washington, D.C.; U.S. Government Printing Office 1979) 1978 data from table A 2, U S Department of Interior Federal Coal Management Report Fiscal Year 1979 (Washington D C U S Government Prlntlng Office. 1980), 1979 data from table 16, ch. 3 of this report

ings significantly since 1965 both in absolute and relative terms. Steel companies and metals and mining companies were early leasing participants, but steel industry influence has declined steadily in relative terms since 1950, although the acreage held by the steel industry has steadily increased since 1950. Metals and mining company leaseholdings have varied widely, due in part to the 1977 sale of Peabody Coal Co. by Kennecott Copper Corp. Independent land companies played a significant role in leasing in the 1950's and 1960's, but they have largely liquidated their holdings over the past decade.

Table 1 shows the acres held under lease by the principal categories of leaseholders and the amount of Federal coal they produced in the early and late 1970's. There is a fairly close correspondence between the share of Federal leased acreage and the share of coal production in 1979. A striking exception is the case of the metals and mining companies, which accounted for 16 percent of Federal coal production in 1979 while holding only 2 percent of leased acreage.

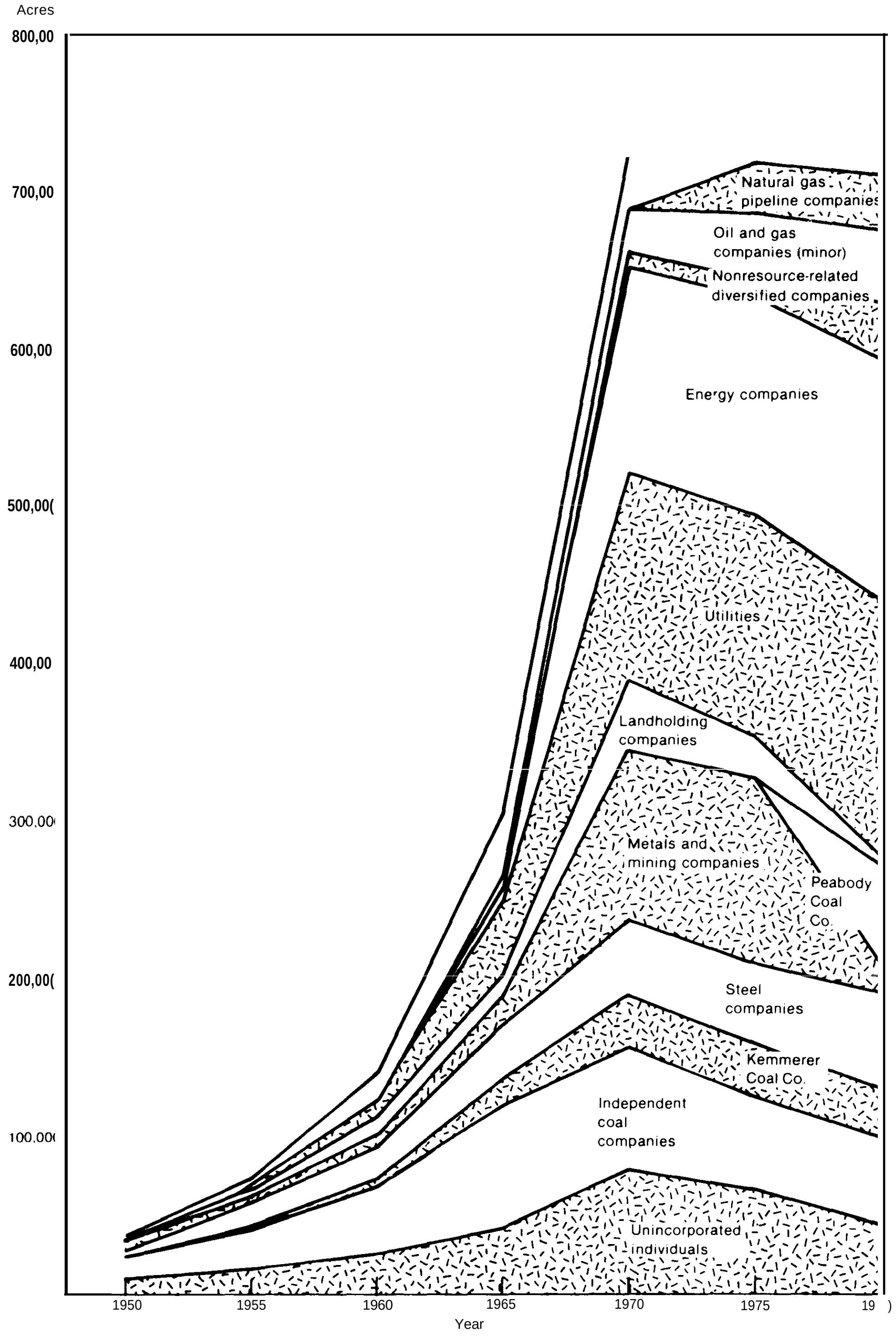
The ownership data reveal little evidence of concentration of leaseholdings between 1950 and 1980. The number of leaseholders approximately doubled in that period, from 84 to over 160 while the number of leases increased sixfold from 88 to 565 and the leased acreage increased by nearly a factor of 20, from about 41,000 acres to 812,000 acres, The four largest leaseholders in 1950 controlled 32 percent of all land under lease while the largest eight controlled 34 percent in 1980. Leaseholders in 1980 came from nine business categories, up from four categories in 1950. On the average, a leaseholder held three times as many leases and 10 times the acreage in 1980 as in 1950.

Three trends in the nature of leaseholders are noteworthy: 1) There is a growing involvement in the leasing program by horizontally integrated companies, The energy companies, natural gas pipeline companies, and the smaller oil and gas companies together hold 31 percent of leased acreage and produced 29 percent of Federal coal in fiscal year 1979. 2) There is a growing involvement of companies for which coal production represents a vertical integration of business activities. Steel companies and electric utilities are the principal examples of vertical integration among leaseholders, Together, the two groups hold 29 percent of coal land under lease. 3) There is a growing involvement of large, already diversified companies in coal leasing, including metals and mining companies and chemical and high technology companies.

Lease Development Status

A principal objective of this study is to assess the development potential of existing

Figure 8.— Number of Federal Coal Acres Under Lease by Business Activity Category, 1950-80



SOURCE: Off Ice of Technology Assessment

Table 1 .—Federal Leaseholdings and Production by Business Category

Business activity category	1970 leased acres	1972 coal production from Federal leases	1980 leased acres	Fiscal year 1979 coal production from Federal leases
Electric utilities . .	18% 132,038	47% 4.8	21 % 163,259	30% 17.8
Energy companies. .	18% 132,274	5% 0.51	20% 155,024	16% 9.9
Metals and mining companies	12% 107,504	12% 1.2	2 % 17,620	16% 9.3
Oil and gas companies (minor)	4%0 26,911	2 % 0.23	6 % 45,926	9 % 5.3
"Other" companies . .	6 % 41,153	4 % 0.46	10% 77,861	9 % 5.2
Independent coal companies . . .	11 % 78,297	20% 2.0	7% 55,410	7% 4.4
Natural gas pipeline companies ., . .	0% 0	0% 0	5% 36,317	4% 2.4
Peabody Coal Co.	8% [a] a	0% [a] a	8 % 62,009	4 % 2.2
Steel companies . . .	6 % 46,114	7 % 0.77	8 % 60,015	2 % 1.3
Non resource diversified companies	1% 10,015	0% 0	5 % 35,675	2 % 1.0
Unincorporated individuals . .	11 % 78,995	3 % 0.27	6 % 43,215	1 % 0.72
Kemmerer Coal Cob	5 % 33,793	0 % 0	4 % 32,191	below 1% 0.06
Total	94% 687,094	100% 10,3	99% 784,522	100% 59.5

NOTE. Percentage sums might not equal totals because of rounding All land holdings listed as acres. All production listed in million tons of coal.

[a] **Peabody** 1970 land holdings and 1972 productions totaled In metals and mining category

[b] In March 1981, Kemmerer Coal Co was purchased by Gulf Oil Corp.

SOURCE Office of Technology Assessment

leases, For this analysis, OTA combined the existing leases into units or blocks, A lease block, as defined in this report, consists of one or more leases owned by the same lessee(s) that are contiguous or sufficiently close together to form a compact minable unit,

Using this approach, OTA divided the 565 existing coal leases into 256 blocks. The smallest blocks contain one lease covering 40 acres, The largest, located in southern Utah, includes 21 leases and 47,000 acres.

OTA conducted a comprehensive study of mining and development activities and production prospects for the 548 Federal leases in 244 lease blocks located in the seven States of Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming. To facilitate this analysis, OTA grouped the lease units in three categories based on the status of the mine plan.

Before a coal mine can produce coal from Federal land, a mine plan must be approved by DOI. Hence, determining mine plan status is a useful first step in assessing lease development potential, Accordingly, the lease blocks in this report are grouped in the following three development categories based on a review of all mine plans on file at the Office of Surface Mining (OSM) on September 30, 1980:*

- producing or have approved mine plans,
- have mine plans submitted and pending approval, and
- have no submitted mine plan ("undeveloped"),

Figure 9 summarizes the mine plan status of leases, leased acreage, and recoverable reserves by State for the seven principal Federal coal States.

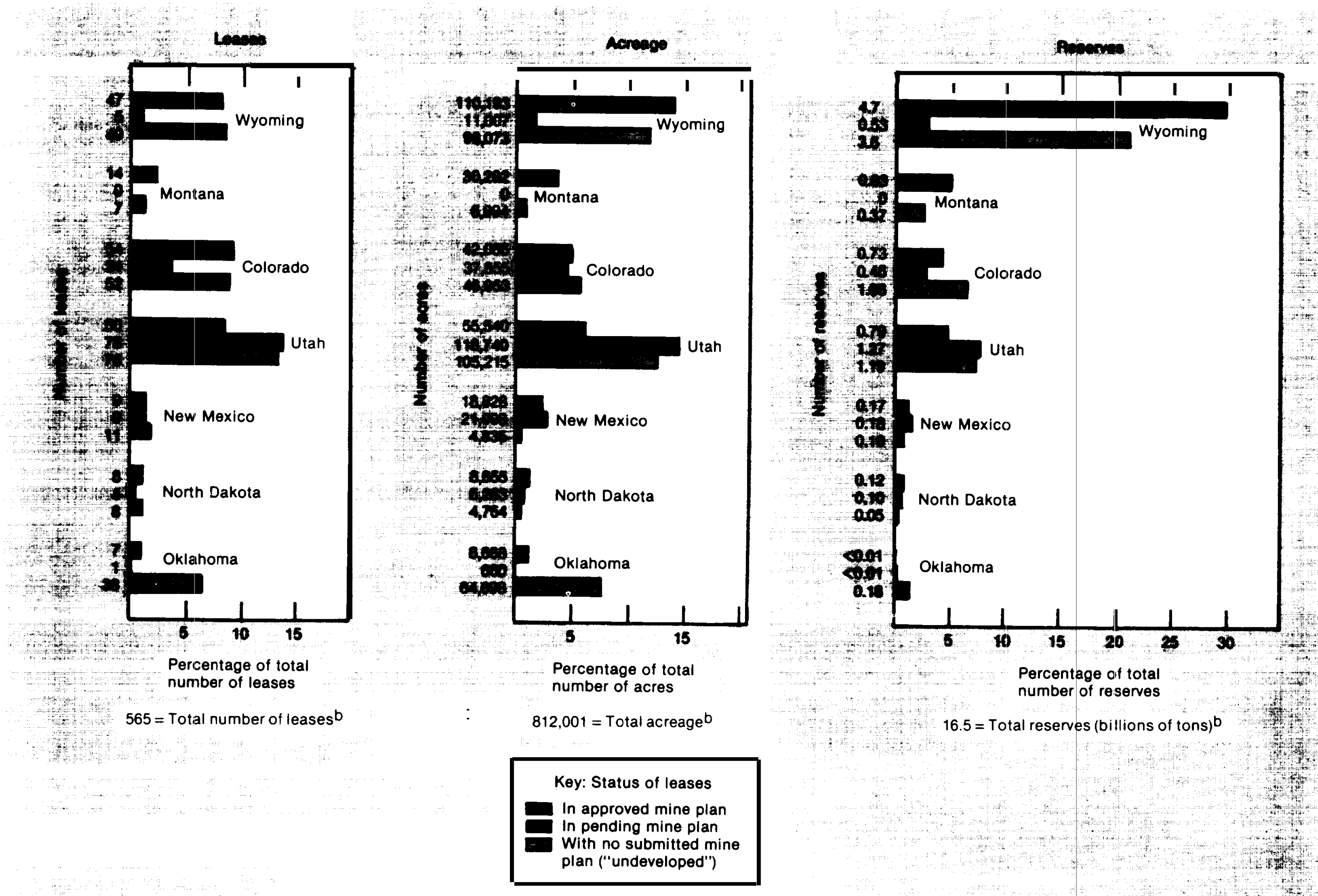
Approximately one-third of all Federal leases are either producing or have approved mine plans. This category also includes leases issued in 1979 and 1980 to permit the continued operation of existing mines (regardless of whether or not they have formally been included in approved mine plans) and leases which have been included in amendments to approved mine plans.

The highest percentage of leases in the approved mine plan category is in Montana: 67 percent of leases covering 69 percent of the leased reserves in the State. Utah and Oklahoma have the smallest percentages of leases and the lowest percentage of leased reserves in the approved categroy.

Although not every lease falling into the approved mine plan category is producing coal, all Federal coal production was mined from leases in this category. In 1979, 60 million tons of coal were mined from 83 Federal

*Both surface and underground mine plans are on file at the U.S. Office of Surface Mining.

Figure 9.—The Development Status of Federal Coal Leases[a]



[a]See also table 14 in ch. 3 of the full report.

[b]Although 17 leases in seven States covering 13,555 acres and with about 0.1 billion tons of recoverable reserves are not plotted in this figure, these leases, their acreage and their reserves are contained in these totals.

SOURCE: Office of Technology Assessment.

leases, over 40 percent of the leases in the approved category. * In 1979, Federal coal contributed 36 percent of all production from the seven Federal coal States shown in figure 9. Federal coal provided 58 percent of Utah's coal production, 42 percent of Wyoming's coal production, 7 percent of the coal mined in North Dakota, and 6 percent of the coal mined in Oklahoma (see fig. 5). The pattern is similar for 1980 (table 2).

Approximately 20 percent of all leases and 15 percent of leased reserves are included in mine plans which are pending approval at OSM. This category does not distinguish among lease units according to the quality of submitted mine plans, their date of submission, or the present position of the mine plan in the regulatory review process.

Utah and New Mexico have the highest percentage of leases in the pending mine plan category, 38 and 31 percent, respectively. On the other hand, no pending mine plans for Montana leases have been submitted to DOI and only one of Oklahoma's 46 leases is included in a pending mine plan.

Forty-four percent of all leases, 42 percent of all leased acreage, and 40 percent of leased reserves have not been developed to the point of a mine plan submission to OSM. Preliminary development activity varies widely on these undeveloped units, from extensive exploration drilling and mine plan preparation on some units to no activity at all on others.

Oklahoma has the highest percentage of leases and leased acres and reserves in the undeveloped category; five of the seven Western States have over 30 percent of their leased Federal reserves in this category. Thirty-eight percent of New Mexico's leases and 40 percent of North Dakota's leases have no mine plans but they cover just 22 percent and 19 percent, respectively, of leased reserves. These are lowest percentages of reserves in the undeveloped lease category among the seven Western States.

*Because only a portion of the approved permit area is mined in any given year, it is unlikely that all Federal coal leases in approved mine plans will be producing at one time.

Table 2.—1979 and 1980 Coal Production From the Seven Federal Coal States Studied in This Report[a] (all production in millions of tons per year)

State	1979 Federal production	1979 Production from Federal mines[b]	1979 Total State production	1980 Federal production	1980 Total State production
Colorado	7.7	16.0	18.1	9.4	19.5
Montana	8.6	27.4	32.5	10.4	36.1
New Mexico	5.4	8.4	15.1	6.3	16.5
North Dakota	1.1	14.1[c]	15.0	0.6	17.2
Oklahoma	0.3	0.3	4.8	0.3	4.9
Utah	6.9	10.4	11.8	8.7	13.1
Wyoming	30.1	67.5	71.8	33.4	94.0
Totals	60.1	144.1	169.1	69.1	201.4

[a]TOTAL U S COAL PRODUCTION IN 1979 776 MILLION TONS.
TOTAL U S COAL PRODUCTION IN 1960 820 MILLION TONS.
[b]Coal from Federal coal leases IS referred to as *Federal coal* A mine which Includes a Federal lease IS called a *Federal mine.* Sometimes, for the sake of efficiency of recovery or economy of operations, intervening State or private coal IS mined with Federal lease(s) in the same mine This practice is the rule in Southern Wyoming and North Dakota, for example Thus, many Federal mines produce both Federal and nonfederal coal A mine which contains no Federal coal IS called a *non-Federal* mine Total coal production in a State or region IS thus the sum of 1) Federal coal production from Federal mines *plus* 2) Non. Federal coal production from Federal mines p/us 3) Nonfederal coal production from nonfederal mines
[c]This figure includes 56 million tons of production from operating mines with Federal leases in pending mine plans Al I of this 56 million tons is from non-Federal reserves

SOURCES 1979 Federal productlion from U S Geological Survey accounting office
1979 State production from the U S Energy Information Agency, *Weekly Coal Production Report,* Aug. 16, 1980
1980 Federal production from U S Geological Survey, *Federal and Indian Lands,* Coal, *Phoshpate, Potash, Sodiurn and Other Mineral Production,* Royalty Income *and Related* Statistics (Washington, D C U S Government Printing Office, June 1981).
1980 State production from the U S Energy Information Agency, personal communication to OTA, July 27, 1981

Potential Production From Federal Coal Leases in 1986 and 1991

The development and production estimates presented in this report are based on information in mine plans, the deliberations of the OTA State task forces* and communications with the lessees. Although OTA based its evaluations of likelihood of development and levels of potential production on the best data available for each lease at the time, as additional information based on further exploration and development becomes available, the prospects for any given lease could change.

These estimates of potential production from Federal leases are not forecasts of the coal that will be produced at a given price or given demand. They are estimates of the total amount of coal that could be produced from currently operating Federal mines and from those Federal leases that have characteristics comparable to operating mines in the same region. Coal from these leases would thus be likely to have mining costs competitive with costs at currently operating mines in the same area. If the overall demand for Federal coal does not increase to the production levels that are possible, then not all of the Federal leases that could technically and economically be developed will go into production.

*OTA task forces were held in Colorado, New Mexico. Oklahoma. Utah, and Wyoming. For a complete listing of task force participants, see p. vii of this report.

Development Prospects of Undeveloped Federal Coal Leases

Of the 502 leases in the six major Western coal States of Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming, 203 are not in mining plans. These leases cover nearly 265,000 acres, contain 6.4 billion tons of recoverable reserves, and have the potential to contribute substantial coal production within the next 10 years. Along with five leases in three pending mine plans in Wyoming, OTA called these leases "undeveloped" and has evaluated the likelihood that they will be developed within the next 10 years (see table 3), Geological, technical, ownership, environmental, transportation, and community factors were considered in the evaluation process,

Of the 208 leases analyzed as undeveloped, 80 leases containing 4.1 billion tons of recoverable reserves have favorable prospects for development by 1991. The majority of these reserves are concentrated in the Wyoming portion of the Powder River basin (3,2 billion tons of surface-minable reserves) and in the

Table 3.— Development Potential of Undeveloped Leases[a]

State	Number of undeveloped leases	Amount of undeveloped reserves (Billions of tons)	Undeveloped leases with favorable development potential		Undeveloped leases with uncertain development potential		Undeveloped leases with unfavorable development potential	
			No. of leases	Amount of reserves	No. of leases	Amount of reserves	No. of leases	Amount of reserves
Wyoming, ...	**54**	**4.2**	**35**	**3.5**	**7**	**0.67**	**12**	**0.03**
Montana	7	0.37	2	<0.1	1	<0.1	4	<0.3
Colorado.	52	1.06	10	0.08	21	0.82	21	0.16
Utah.	76	1.19	30	0.42	28	0.70	18	0.06
New Mexico	11	0.10	2	0,09	5	0.001	4	<0.001 [b]
North Dakota	8	0.05	1	<0.01	3	0.05	4	0.006
Total	208	6.9	80	4.1	65	2.3	63	0.5

[a]Includes **five leases in** Wyoming in three pending mine plans.
[b]One-half million tons.
SOURCE Office of Technology Assessment

Uinta region of Utah (0.4 billion tons of underground reserves). In almost all cases, the lessees are actively developing these leases.

Another 65 leases containing 2.3 billion tons of recoverable reserves have uncertain prospects for development by 1991. The large majority of these reserves (about 90 percent) are about evenly divided among the Kaiparowits Plateau coalfield of southwestern Utah, the Green River region of Colorado and the Wyoming portion of the Powder River basin, Development depends on factors such as pace and scale of construction of associated powerplants or synfuels projects, development of in situ gasification, availability of additional Federal reserves from pending PRLAs or from new lease sales, construction of transportation systems, and lessee development priorities.

Considerable uncertainty faces the three lease blocks (with a total of 0.6 billion tons of recoverable reserves) in the Powder River basin whose development is dependent on in-situ gasification, a technology in the experimental stage which is not likely to be ready for commercial application before the 1990's. Considerable uncertainty also faces the 25 undeveloped leases with 0.7 billion tons of reserves located on the Kaiparowits Plateau coalfield of southwestern Utah. The leases in this large, isolated, rugged area face uncertainty in potential development over the next decade because construction of the rail or slurry transportation systems to connect the area with potential markets depends on a minimum production in the area of over 30 million tons per year—a scale that is unlikely to be reached in the next decade.

Finally, 63 leases with approximately 0.5 billion tons of recoverable reserves are unlikely to be developed. Most of these leases lack sufficient minable reserves of marketable quality to be developed as new mines. Many also have difficult mining conditions that would make them expensive to develop. Some of the leases are located outside active mining areas and lack adequate transportation. For example, a seven-lease block in Colorado that meets the minimum requirements for an average new mine in its region is located in a remote area without rail service. It is unlikely that it will be developed in the next decade, given the availability of other coal sources with adequate transportation and which are closer to potential markets.

Production and Capacity Estimates for 1986 and 1991: Developed and Undeveloped Leases

Production estimates for 1986 and 1991 were made on a lease-by-lease basis and summed by region and State. The 63 undeveloped leases in the above six States with unfavorable development prospects were assumed to have zero production. A range of production was usually estimated for the 145 undeveloped leases with favorable or uncertain prospects for development. With a few exceptions, the lessee's estimates for production were used for leases in mine plans.

North Dakota, Montana, and Wyoming

In 1979, mines with Federal leases in these three States produced 109 million tons of coal, over 90 percent of the total amount of coal produced in this area. The lessees plan to increase production from currently operating Federal mines substantially, to 280 million tons in 1991. Currently undeveloped leases could add another 20 to 80 million tons per year of production in 1991, for a total production from Federal mines in that year of 300 million to 360 million tons.

In the Powder River basin of Wyoming and Montana, Federal mines accounted for 88 percent of total coal mine capacity in 1980. This percentage is projected to remain relatively constant throughout the decade, However, production from Federal leases themselves is projected to increase from less than 40 percent of total coal production in the basin in 1979 to approximately 80 percent in 1991. In southern Wyoming, essentially all coal production is from Federal mines, with about one-third of the production from the Federal reserves. This pattern is expected to continue, with the contribution from Federal reserves rising to perhaps 40 percent by 1991. In 1979, Federal mines in the North Dakota portion of the Fort Union region accounted for over 90 percent of the State's coal production; the amount produced from Federal reserves was less than 7 percent. This situation is expected to continue, with however, production from Federal reserves rising to perhaps 20 percent in 1991.

Figure 10 summarizes potential production and planned mine capacity for Federal mines over the next decade for the Fort Union region of North Dakota and Montana, for the Powder River basin of Montana and Wyoming, and for southern Wyoming. The upper capacity lines (lines D) in this figure represent OTA's estimate of the maximum coal production from Federal mines that could be achieved in these three regions under strong market conditions. Several features of figure 10 should be noted:

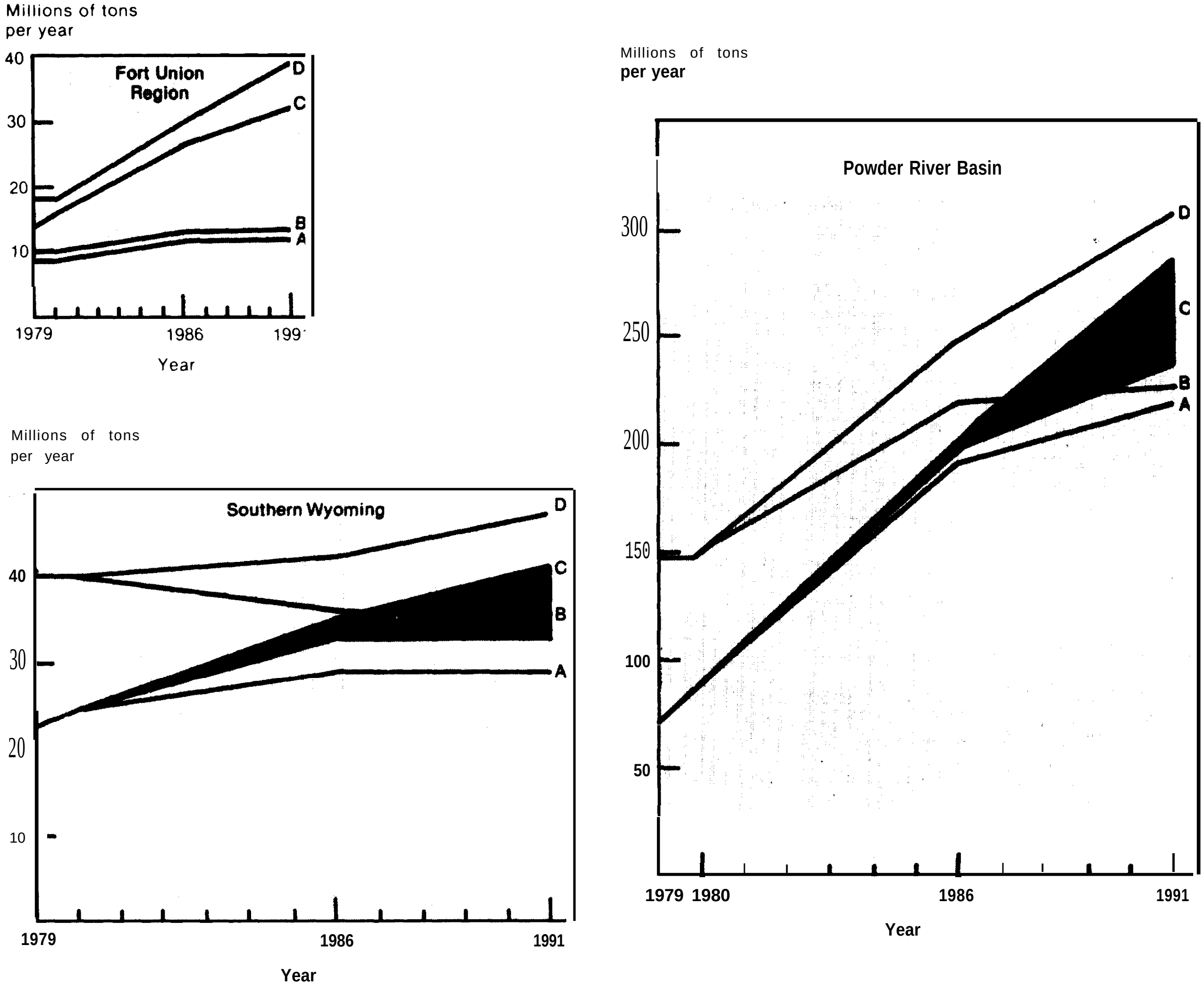
1. The Powder River basin will continue to increase in importance as a coal-producing region. By 1991, Federal mine production in the Powder River basin could account for about 80 percent of Federal mine production in these three States.
2. All estimated Federal mine production for 1991 for the Powder River basin comes from currently approved mines and from undeveloped leases with favorable development potential. (Undeveloped leases with uncertain development potential contribute no production through 1991.) The large range in estimated production from undeveloped leases arises from demand uncertainty. However, several undeveloped leases in the Powder River basin have contracts for delivery of coal before 1990.
3. By 1991, the capacity of Federal mines in the Powder River basin could be as high as 310 million tons per year. According to the lessee's plans, the overcapacity in presently operating Federal mines in the Powder River basin, which was greater than 75 million tons per year in 1979 will diminish to nearly zero by 199l.
4. The maintenance of total capacity of Federal mines in southern Wyoming depends on the development of new mines. Although capacity of presently operating mines is projected to decrease over the next 10 years, their production will probably not decline. Most of the range in production arises from uncertainty in the pace of a synfuels project.
5. The potential increase in production and capacity of Federal mines in the Fort Union region will occur largely from mines in North Dakota with leases in currently pending mine plans. Undeveloped leases are not likely to contribute more than 1 million tons per year by 1991. Federal mine production in the Montana portion of the region is likely to remain constant at 0.3 million ton per year.

Colorado, New Mexico, and Utah

In 1979, mines with Federal leases in these three States produced a total of 35 million tons of coal, about 77 percent of the total amount of coal produced in this area. Many of the Federal mines in the area are relatively new and have not yet reached full production levels; consequently, the lessees plan to increase production from currently operating mines substantially, to 65 million tons per year by 1991. Over the next decade, several operating mines are expected to be at, or near, depletion of their current mine plan reserves. Part of this reduction in capacity will be offset by replacement capacity from new mines on Federal leases. About 5 million to 10 million tons are potentially involved.

If all currently operating and proposed mines that include Federal leases are developed and produced as planned, production from these mines could reach 75 million tons by 1986, and between 110 million and 146 million tons by 1991. The production increase would be greatest in Utah, where production from Federal mines might rise from about 10 million tons in 1979 to as much as 74 million tons by 1991.

Figure I0.—Planned Capacity and Potential Production of All Mines With Federal Leases in the Powder River Basin, Southern Wyoming, and Fort Union Region



A: Lessee's planned annual production from Federal mines in currently approved mine plans only

B: Lessee's planned annual capacity for Federal mines in currently approved mine plans only

C: The sum of *A*, above, plus estimates of potential production from Federal mines in pending mine plans and from presently undeveloped Federal leases

D: Planned annual capacity for all Federal mines, including Federal mines in pending mine plans and presently undeveloped Federal leases

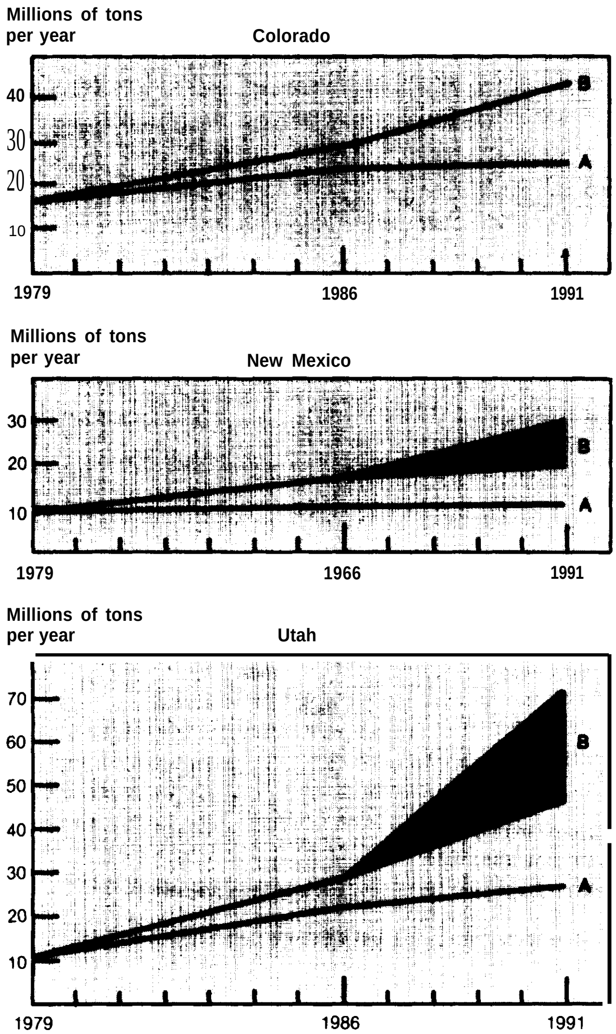
SOURCE Office of Technology Assessment

Over the next decade, the percentage of total State production coming from existing Federal coal leases is expected to increase in Utah and Colorado as new, large Federal mines reach full operation, The percentage of Federal production from existing leases in New Mexico is expected to remain relatively stable, although, output from PRLAs could increase the total share of annual State production from Federal reserves.

Figure 11 summarizes potential production for Federal mines over the next decade for the States of Colorado, New Mexico, and Utah. Several features of figure 11 should be noted.

1. Most of the projected increases in production will come from new mines on leases in pending mine plans and on currently undeveloped leases that will not achieve full design capacity until after 1991. The projected 1991 production range of 110 million to 146 million tons is less than the total capacity of about zoo million tons per year that could be supported by mines on existing Federal leases in these States by the mid-1990's. In the late 1990's, however, the capacity supported by existing leases will begin to decline as many of the mines that are now operating exhaust their reserves.
2. For Colorado, the increased production comes from new mines with pending mine plans and from undeveloped leases. The new mines could add from 25 million to 30 million tons of new annual capacity split almost evenly between surface and underground operations. About 1.9 million tons of projected 1991 production is tied to synthetic fuel projects but could be sold to other customers if the proposed projects were delayed. The major uncertainty facing increased production in Colorado is whether expanded markets will materialize as expected.
3. The range of potential production from new mines in New Mexico in 1991 reflects the uncertainties in the rate of mine development because of possible delays in the construction of the Star Lake Railroad and in the availability of reserves in pending PRLAs associated with two new mines. Production levels and mine capacity for the Black Lake Mine will also be influenced by the requirements of a proposed coal gasification project. Two other new mines are unaffected by PRLA availability or railroad construction, but are tied to the coal needs of new powerplants.
4. The range of 27 million tons per year in 1991 production in Utah arises from uncertainties in development in the Alton and Kaiparowits coalfields of southwestern Utah. Coal development in southwestern Utah depends on expansion of potential markets only the Alton

Figure 1 1.— Potential Production Capacity of All Mines With Federal Leases in Colorado, New Mexico, and Utah



A: Lessees' planned annual production capacity for Federal mines in currently approved mine plans only.
B: The sum of A, above, plus estimates of production capacity for Federal mines in pending mine plans and for presently undeveloped Federal leases.

SOURCE. Office of Technology Assessment

mine currently has a purchaser for its coal) and, more importantly, on the construction of a rail or slurry transportation system to serve potential consumers, A minimum of 30 million tons annual production is required to offset the costs of constructing a rail line onto the Kaiparowits Plateau,

Oklahoma

In **1979,** approximately 0.3 million tons of Federal coal was produced in Oklahoma. Four mines with Federal leases are currently producing coal in this State; however, the Federal reserves on three of these mines are expected to be depleted before 1986. No undeveloped leases in Oklahoma are expected to produce coal in commercial quantities before 1991, Three main reasons account for the unfavorable production prospects of these leases: 1) difficult and costly underground mining conditions, 2) a depressed metallurgical coal market, and 3) a high Federal royalty relative to royalties charged for fee coal in the State.

Diligent Development

Federal coal leases issued before August 4, 1976 (527 out of the 565 leases in this study)* are required to produce 2½ percent of logical mining unit** (LMU) recoverable reserves by June 1, 1986, or be subject to cancellation proceedings. Under certain specific circumstances, the Secretary of the Interior may grant an extension to mid-1991, (See ch. 9 for more detail.)

Most leases with potential for production by 1991 could qualify for extensions under existing guidelines. The exceptions are mines that do not fit clearly into any of the current guidelines, specifically several proposed small- to medium-sized mines that are intended to serve spot markets and several underground mines with difficult mining conditions requiring longer construction periods.

OTA has examined estimated production schedules to assess the likelihood that a lease block will achieve diligence by 1986 or 1991.

By 1991, over 70 percent of the 502 leases in the six major Western Federal coal States might meet the existing diligence requirements.

- **216** leases with 7.4 billion tons of reserves are likely to meet diligence by 1986 (45 percent of total leased reserves).
- 29 additional leases with 2.1 billion tons of reserves are likely to meet diligence by 1991 with extensions (13 percent of total leased reserves).
- 112 leases with 3.4 billion tons of reserves (20 percent of total leased reserves) are uncertain to meet diligence by 1991. Major uncertainties are tied to delays in powerplant, synfuels and transportation system construction, fluctuations in captive coal needs, development of markets for the coal, and difficulties in defining the logical mining unit for leases with very large reserves in multiple seams. Development of markets for the coal constitutes a particularly important uncertainty in the Powder River basin where market demand will be an important factor in determining whether 1.2 billion tons of recoverable reserves under lease will meet diligence by 1991.

Thirty percent of the leases in the six major Western Federal coal States containing 20 percent of total leased reserves are unlikely to meet diligence by 1991 even were they to be granted extensions:

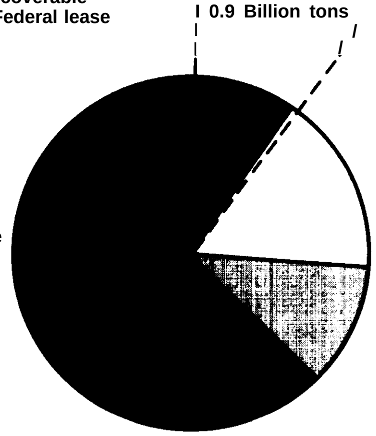
- Production for 61 leases in the Kaiparowits Plateau with 1.4 billion tons of reserves is dependent on construction of a coal transportation system that is unlikely to be in place by 1991. Moreover, even if the Kaiparowits Plateau leases begin producing at the earliest feasible date, 1987, it is unlikely that they would

* Thc **38 leases issued** after August 4, 1976. are subject to a slightly **different** requirement. None of these leases are anticipated to have difficulty in meeting that requirement t.

**The Bureau of Land Management has defined every lease as an LMU. This definition may be, but is not necessarily, superseded when a mine plan is approved. In a mine plan, a n LMU may consist of more than one Federal lease and may include non-Federal coal 1.

produce enough to meet diligence requirements because of the large amount of underground reserves involved.
- Development of 10 leases in the Powder River basin with 1.4 billion tons of reserves depend on onsite synfuels development; 0.6 billion tons of these are suitable only for in situ gasification, assuming that technology is developed.
- The remaining 74 leases are primarily small, scattered leases with poor quality reserves that are unlikely to be developed.

Figure 12.— Dilligent Development Summary for the Powder River Basin



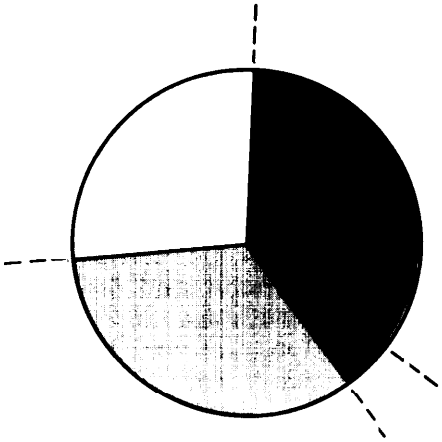
Key	Reserves[a]	Percent of reserves
Likely to achieve diligence by 1986:	4.8	52%
Likely to achieve diligence by 1991:	1.7	18%
Uncertain whether will achieve diligence by 1991:	1.2	13%
Unlikely to achieve diligence by 1991:	1.5	16%

[a]Billions of tons.

SOURCE: Office of Technology Assessment.

Figures 12 and 13 graphically summarize the results of OTA's diligent development analysis for the Southern Rocky Mountain region (Colorado, Utah, and New Mexico) and for the Powder River basin.

Figure 13.— Diligent Development Summary for the Southern Rocky Mountain Region (Colorado, New Mexico, and Utah)



Key	Number of leases	Percent of leases	Reserves[a]	Percent of reserves
Likely to meet diligence by 1986	136	28	2.0	34
Likely to meet diligence by 1991	15	4	0.3	5
Uncertain to meet diligence by 1991	95	26	2.0	34
Unlikely to meet diligence by 1991	114	32	1.6	27

[a]Billions of tons.

SOURCE Office of Technology Assessment

The Powder River Basin

The Powder River basin is particularly important to Federal coal development because it contains over one-half the recoverable reserves under lease, accounts for about one-half the coal produced from Federal mines, contains the largest pool of Undeveloped leased Federal coal reserves in the United States, and has the largest market area of any Western coal-producing region. Federal mines accounted for 88 percent of mine capacity in the Powder River basin in 1980. This Percentage is projected to remain relatively constant throughout the decade. However, production from the leases themselves is projected to increase from less than 40 percent of total coal production in the basin in 1979 to approximately 80 percent in 1991. *

A number of projections for this region suggest that the most likely range of demand for Powder River basin coal in 1990 will be 200 million to 225 million tons per year (see fig. 14), The Department of Energy (DOE) interim midrange production goal of 275 million tons per year is probably high.**

Contracts already exist for delivery of 186 million tons per year of Powder River basin coal in 1990. Of this amount of contracted coal production, 159 million tons is from currently producing mines with Federal leases, 10 million tons is from non-Federal mines, and 17 million tons is from presently undeveloped Federal leases,

For 1990, lessees and non-Federal mine operators have plans to produce a total of nearly 100 million tons per year more than the presently contracted level for that year. Production plans for 1990 total 280 million tons per year; of this amount, 215 million tons is from currently producing mines with Federal leases, 10 million tons is from non-Federal mines, and 55 million tons is from presently undeveloped leases which have favorable production prospects for 1990 under strong market conditions. Only 6 million tons of this production is contingent on synfuels development.

Mine design capacity planned by lessees and non-Federal mine operators for 1990 is considerably higher: 348 million tons per year. Mine design capacity is an upper limit to long-term production levels that can be reached with a leadtime of a year or so. Currently operating Federal mines are scheduled to reach 97 percent of mine design capacity by 1991. Therefore, given sufficient market demand, production levels of close to 350 million tons per year are attainable in the early 1990's from currently operating mines plus good quality properties currently being actively developed.

These levels of capacity and production depend on all plans being realized for both Federal and non-Federal properties, If only 11 out of the 17 undeveloped properties contributing to this projection are developed, total design capacity could be reduced by up to 60 million tons per year; total design capacity would then be 290 million tons per year. Nevertheless, planned capacity in the Powder River basin seems likely to be adequate to meet demand into the early 1990's.

Potential capacity in the post-1990 period is considerably more difficult to estimate, as is potential demand. An additional 155 million tons per year of capacity could perhaps become available in the post-1990 period from undeveloped Federal leases, PRLAs and new non-Federal mines. About 70 million tons per year of this capacity would be suitable only for onsite development because of low coal quality, This amount (155 million tons per year) should be considered an upper limit rather than a likely value of additional post-l990 capacity without additional leasing of Federal coal. For the post-1990 period, demand projections become very uncertain, The DOE preliminary midlevel production goals, the ICF CEUM* midlevel production forecast and the DOE midlevel final production goals for 1995 for the Powder River basin are 382, 306, and 491 million tons per year, respectively. The DOE final production goal. 491 million tons per year. reflects several policies about increased coal use (e. g., coal for synfuels), that cause the number to be higher than other forecasts. Although all demand projections past 1990 should be regarded as very uncertain, the lower numbers above are, as of now, more likely to be realized.

The potential for continued high overcapacity in the Powder River basin has caused

*The percentage of Federal coal production will be less than the percentage of Federal mine capacity. because Federal mines commonly produce some non-Federal coal. See footnote on p 3 and table 59

**The demand projections are discussed in [illegible] on pp 169-173 and fig. 34. See also pp 100-102 for a discussion of the DOE final production goals.

* See footnote on fig. 14 for citation.

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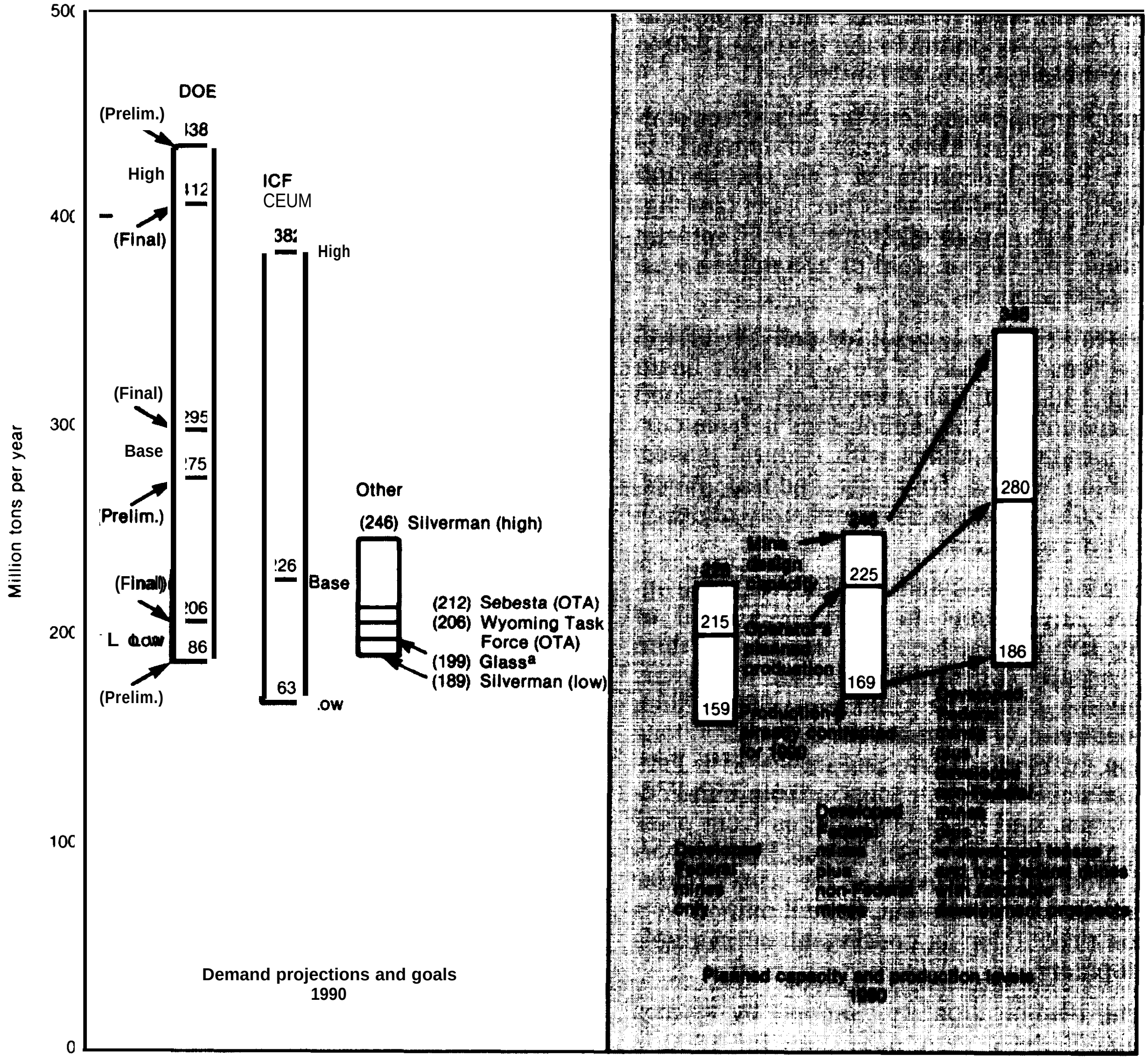
Figure 14.—Comparisons of Powder River Basin Demand Projections With Planned Capacity and Production Levels for 1990



a Calculated by adding Sebesta's figure for the Montana portion of the Powder River Basin (68 mmt) to Glass' figure for the Wyoming portion (133 mmt).

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Sebesta: *Demand for Wyoming Coal 1980-1991 Based Upon Protected Utility* Coal *Market and Demand for Montana Coal 1980-1991 Based Upon Prptected Utility Market* (Washington, D. C.; Office of Technology Assessment: October 1980).

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DOE: *Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995.* (Washington, D C.. DOE, August 7, 1980). See also: *Analysis and Critique of the Department of Energy's August 7, 1980 Report Entitied: "Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995,* prepared for the Rocky Mountain Energy Company, (ICF Incorporated; Washington, DC.: October 1980)

DOE: The 1980 Biennial Update of National and Regional Coal Production Goals for 1985, 1990 and 1995. U.S. Department of Energy (Washington D.C., January 1981).

questions to be raised about the timing, extent and location of renewed large-scale leasing under the Federal Coal Management Program. The debate focuses on the role of competition and the free market in resource supply, the potential costs to the social and physical environments of the coal producing areas of "overleasing," the length of time needed to bring a new lease into full-scale production, the margin of supply safety needed for prudent planning on a national and corporate level, questions of equity raised by restricted opportunities for new entrants to Federal leaseholding, a fair return to the public for use of its resources, and the levels of likely demand in the early to mid-1990's,

Many proponents of large-scale new leasing in the Powder River basin in the near future cite the long moratorium on such leasing and its effect of restricting entry possibilities to leaseholding as one reason for prompt resumption. They also contend that postponing leasing will unduly interfere with the workings of the free market and will restrict competition. They anticipate high demand for coal by 1995 and fear that the present leased reserve base in the Powder River basin will not provide enough certainty or flexibility to meet that demand efficiently. Opponents of large-scale new leasing in the Powder River basin as scheduled in 1982 cite the potential for overcapacity through the early 1990's as proof that such leasing is not necessary at this time. They contend that leasing can be safely deferred until its necessity is clearly indicated by realistic demand forecasts. They hold that large-scale leasing substantially beyond that necessary to meet likely demand in 1990 will place an unnecessary strain on orderly planning in the communities of the region, shift demand to the Powder River basin that could have been met by Midwestern supply, depress the value of leases so that the public will not receive a fair return for its resources, and, moreover, be unlikely to increase competition significantly.

Factors Affecting Federal Lease Development and Federal Coal Production

There are a number of market, environmental, legal and regulatory, transportation, and socioeconomic factors that could affect Federal lease development and coal production.

Market Factors

Most energy forecasts predict that the major Federal coal States in the West will attract larger shares of the total coal market over the next 10 years. Several studies project that Western coal, which supplied 28 percent of the 1979 U.S. demand, will supply as much as 49 percent of the market by 1990. *

*Western coal here refers to *all* coal mined west of the Mississippi River.

Many factors will influence the demand for Western coal and the competition between Western coal States for markets, but three are particularly significant: demand by domestic electric utilities, growth of new non-utility markets, and transportation availability y and cost.

The principal markets for Western coal are utilities in the Western coal-producing States, the Midwest, and the Southcentral States. The electrical growth rates in these regions will probably be the single most important factor affecting demand for Western coal. Also, growth rates and fuel preferences of utilities for new plants in regions such as California, which currently do not burn coal, and the extent of conversion of existing oil- or gas-fired powerplants to coal will shape Western coal demand. The present new source performance sulfur dioxide (SO_2) emission standards, which require sulfur reduction of all coals (thus, reducing the cost advantage to utilities of burning low-sulfur coal), and the decline in electrical growth rates in recent years suggest that the growth in Western coal demand might not be as high as some earlier forecasts had predicted.

New nonutility markets could increase the demand for Western coal, These include foreign coal users, particularly Japan, and the incipient domestic synfuels industry, although neither is likely to substantially affect Western coal demand before 1990. Moderate increases in industrial coal use could increase demand for Western coal somewhat.

Access to reliable, efficient, and low-cost transportation is critical to the success of Western coal producers in selling to out-of-State coal markets. In all Western coal regions, coal transportation costs are increasing, Because these costs can account for over 70 percent of the delivered price of coal in out-of-State markets, the competititive position of Western coal in these markets is not likely to be as favorable in the next 10 years as it was in the previous 10 years.

Environmental Factors

Because almost all Federal coal reserves are located in the Western United States, the environmental and reclamation concerns about Federal coal development are largely those characteristic of Western coal mining. The dominant issues include concern about fugitive dust and its impact on the good to very good air quality of the West, the effect of mining on the sparse water resources of the region, the ability to revegetate mined areas with semiarid and arid climates, the effect of various spoil handling and recontouring requirements on the ability to mine coal, the effect of mining and associated population growth on the region's wildlife populations, and the effect of mining on the region's archeologic resources.

Several important laws and regulations have been adopted to deal with these concerns, The effect of these regulations on Federal coal production has been to remove small amounts of minable coal from the recoverable reserve base, to delay development of other recoverable reserves, to increase the complexity of the mine permit process, and to increase the overall cost of mining, The percentage of recoverable Federal reserves currently under lease that may be prohibited, or subject to delay from mining over the next 10 years because of environmental regulations is between 5 percent and 10 percent of the total currently leased reserves.

Less than 1 percent of currently leased Federal reserves appear likely to be subject to complete prohibition from mining. The remainder of currently leased Federal reserves that may be affected may be subject to delays in mining because of unresolved environmental questions, but the available evidence indicates that most of these reserves will be mined. There are additional leased reserves (mainly in the Kaiparowits Plateau in southern Utah) over which there are potential environmental conflicts, but impediments to development of these reserves are primarily related to nonenvironmental factors such as transportation availability. These estimates of Federal leased reserves adversely affected by environmental requirements are considerably lower than earlier estimates by DOI which indicated that as much as 10 percent of leased reserves might not be developed because of environmental considerations.

The Surface Mining Control and Reclamation Act of 1977 (SMCRA) addresses most of the concerns about the environmental effects of Western coal mining. The act establishes performance standards for mining and reclamation and criteria that must be met before mining permits can be approved. The act is administered in the West largely by the States, with oversight responsibility remaining with OSM. Various other statutes, such as the Clean Water Act, the Clean Air Act, and legislation to protect wildlife also affect coal mining operations. Also, the Federal Land Management Policy Act included environmental provisions in the Federal coal leasing program,

The coal mining industry has severly criticized the regulatory programs generated by these statutes. Criticism has centered on overlapping and inconsistent regulations, problems with enforcement, excessive paperwork requirements, and increases in the costs of mining and in the time needed to develop mines,

This report does not evaluate the issues of cost or the lengthened development process caused by regulations nor does it evaluate the extent to which recoverable Federal reserves will be affected by environmental concerns under the renewed Federal coal leasing program. However, this report does examine the amount of currently leased Federal coal that has been or that may be prohibited from development or subjected to extra delay from recovery. Table 4 summarizes the results of this analysis.

Air-quality concerns. North Dakota coal is lignite, which is uneconomical to transport over any distance and which must therefore

Table 4.—Summary of Impacts to Federal Recoverable Reserves From Environmental and Reclamation Considerations

Issue area	Specific issue	Location of affected area	Federal reserves affected[1] (millions of tons)	Effect[2]
Air resources	**Expansion of mine production rate** in a non-attainment area	Rosebud Mine, Colstrip, Montana	1.5 ret/y after 1985 or about 30 mt of reserve	U[3], effect would be to limit production rate, not prohibit any mining areas
	Permitting of additional power plants near class 1 area where SO_2 levels for existing and permitted but not constructed facilities are currently predicted to be at maximum PSD level. The additional power plants would be fueled by lignite mines in the vicinity.	**West Central** North Dakota	<1oo	U[4], improved air quality modelling techniques being developed
Lands unsuitable for mining	Impacts of coal mining will damage important aesthetic values of Bryce Canyon National Park	Alton Coalfield, Southern Utah	24	Ap[5]-on portion of proposed mine area designated as unsuitable; rest of leasehold unaffected.
Water resources	Subsidence of mine will divert surface and ground water and adversely affect other uses	Mt. Gunnison Mine West Central Colorado	23	U, approval likely if mine will buy or replace senior water rights affected.[6]
	Alluvial Valley floor (AVF) in areas significant to farming	CX Ranch leases Montana portion of the Powder River basin	<100	Ap uncertain[7]
	Developed mines with stream valleys under study as potential AVF where mine plan development has been delayed	Powder River basin, Buckskin, and Spring Creek mines	95	D, mining of valleys expected[8]
	Designated AVF in developed mines. Valleys not significant to farming. Mine plan development affected	Powder River basin, Eagle Butte, Rawhide, Coal Creek mines	61	U, mining of valley expected[9]

Table 4.—Summary of Impacts to Federal Recoverable Reserves From Environmental and Reclamation Considerations—Continued

Issue area	Specific issue	Location of affected area	Federal reserves affected[1] (millions of tons)	Effect[2]
	Potential alluvial valley floors which existed in developed mines prior to passage of SMCRA. Reclamation plans must still be approved	Powder River basin, Big Sky, East Decker, Eagle Butte, Wyodak, Belle Ayr, Jacobs Ranch, and Black Thunder mines	240	U, mining of valleys expected*
	Potential AVFS in undeveloped coal lease areas	Powder River basin	219	U, mining of most valleys expected[8]
Spoil handling and protection of raptor habitat	Limitation on out-of-pit spoil area	Black Butte Mine Green River-Hams Fork region	5	Ap[10]
	Limitation on out-of-pit spoil area	Green River-Hams Fork region	50	Possible problem; resolution uncertain[6,9]
	Mining in environmentally sensitive woody draws	Glen Harold Mine West Central North Dakota	29	D[11]

[1]Total Federal reserves under lease are 16,500 million tons.
[2]Ap-absolute prohibition; D-delay in approval, U-unresolved.
[3]Jurisdiction lies with the Montana Department of Health and Environmental Sciences
[4]Jurisdiction lies with the North Dakota State Department of Health.
[5]Decision made by the Department of the Interior, 1980. Decision under appeal to Federal courts
[6]Jurlsdtction Iies with Colorado Department of Natural Resources and U.S. Office of Surface Mining
[7]Under Section 510(b)(5) of SMCRA. Jurisdiction lies with the Montana Department of State Lands The department has ruled that the alluvial valley floor IS significant to farming. The lessee has asked the department to reconsider its decision.
[8]Jurisdiction lies with Montana Department of State Lands (Spring Creek) and Wyoming Department of Environmental Quality (Buckskin)
[9]Jurisdiction lies with Wyoming Department of Environmental Quality
[10]Lead decision made by OSM
[11]Permit application denied by North Dakota Public Service Commission on grounds that plans for reclamation of wooded draws were inadequate

be sold to onsite or nearby powerplants or synfuels facilities. Permitting of additional coal conversion facilities in west-central North Dakota is currently being delayed, pending further information on the effect of existing and permitted plants on the air quality of nearby Theodore Roosevelt National Park.

Additional Federal coal development could be affected by possible fugitive dust problems. At Colstrip, Mont., where fugitive dust levels presently exceed ambient air standards, future mine expansion will have to address and minimize air impacts.

Lands unsuitable for mining. In Utah, 24 million tons of Federal coal have been removed from mining because of adverse impacts on nearby Bryce Canyon National Park. The remainder of the leased surface minable reserves in the area, about 270 million tons, are unaffected by the decision. The decision has been challenged in Federal court.

Water resource concerns could affect over 700 million tons of Federal recoverable reserves. However, less than 100 million tons may be prohibited from mining. These reserves are located beneath an alluvial valley floor significant to farming and thus can be absolutely prohibited from mining under SMCRA. * Alluvial valley floor concerns may affect another 600 million tons; however mining of these reserves is likely, with especially stringent reclamation standards applied. Development of over 20 million tons may hinge on purchase or replacement of senior water rights that could be affected by mine subsidence.

*The Montana Department of State Lands has ruled that the alluvial valley floor in question is significant to farming. The lessee has asked the Department to reconsider its decision.

Spoil handling and protection of raptor habitat* have removed 5 million tons of Federal recoverable reserves from mining in southern Wyoming. Spoil handling concerns could affect perhaps as much as another 50 million tons in southern Wyoming and northern Colorado. Development of 29 million tons has been delayed in west-central North Dakota because of concerns about reclamation of wooded draws.

In summary, approximately 1 billion tons of leased Federal recoverable reserves out of 16.5 billion tons of leased Federal recoverable reserves have been or could possibly be affected in the following ways by environmental laws and regulations:

- 29 million tons have been absolutely prohibited from mining;
- up to another 100 million tons may be absolutely prohibited from mining;
- 124 million tons have been delayed in the approval process;
- 573 million tons could be affected or delayed but approval is likely; and
- up to another 150 million tons could be affected or delayed and approval is uncertain.

Several reclamation issues where further data are needed or where regulatory decisions have yet to develop a clear pattern, such as the long-term success of revegetation, the hydrologic effects of mining, and the ability to achieve approximate original contour, have not yet resulted in any prohibitions to mining but could become important issues in the future. The long-term success of reclamation in the West is still unproven, but regulatory authorities have approved continued mine expansion based on the short-term success achieved to date.

Laws and Regulations on Management of Existing Federal Leases

The development of existing Federal coal leases may be affected to varying degrees by the resolution of the following legal issues:

*Especially eagle habitat.

- application and enforcement of diligent development requirements;
- exchange of lease and PRLA reserves for unleased Federal coal;
- processing of pending PRLAs; and
- designation of areas unsuitable for surface mining under SMCRA.

Diligent Development

Under current regulations, leases issued before passage of the Federal Coal Leasing Amendments Act of 1976 (FCLAA) (pre-FCLAA leases) that do not produce 2 l/z percent of the lease's logical mining unit reserves by June 1, 1986, can be canceled, Extensions to this diligence deadline may be granted by the Secretary of the Interior under certain circumstances; however, lack of markets is not solely a basis for extensions. Leases issued after August 4, 1976 (post-FCLAA leases) will be terminated automatically if they do not produce coal in commercial quantities within 10 years after the lease is issued. Section 3 of FCLAA (30 U.S.C. 201(a)(2)(A)) also provides that, with a few exceptions, after August 4, 1986, no new leases can be issued to any lessee who is still holding a coal lease from which he has not produced coal for 10 or more years.

The current regulations defining diligence as actual production of coal were first promulgated in May 1976 in response to concerns over the large amounts of Federal coal that had been leased in the 1960's during a period of declining Federal coal production.

Since May 1976, the diligence regulations have been modified slightly to include provisions required by FCLAA and minor editorial clarifications, but the production requirements for pre-FCLAA leases have remained virtually unchanged. *

According to OTA's analysis, under existing regulations, many pre-FCLAA leases

*In 1977, the Department of Energy organization" Act transferred the Secretary of the Interior's authority to establish diligence requirements and minimum production rates for Federal leases to the Secretary of Energy.

will meet diligence by the 1986 deadline or, with extensions, by 1991; a number of others will not and prospects for some remain uncertain. (See Diligent Development section on p. 21,) Since the current diligence standard could change within the broad limits set by statute as a result of policy redirection or court decisions, it is difficult to predict the precise impact of diligence requirements on pre-FCLAA leases.

DOI's diligence standard requiring production of coal on existing leases within 10 years was opposed by mining industry trade groups and many lessees. Legal challenges by lessees to the reasonableness of the regulations and their applicability to pre-FCLAA leases are likely.

The impact of diligence requirements on pre-FCLAA leases will depend on the interaction of many factors besides the legal precedents that may be established on the applicability of the regulations. These factors include: 1) the extent of voluntary compliance by lessees; 2) how many extensions to the 1986 deadline are granted; 3) how many existing leases are combined with other leases or non-Federal coal reserves to meet diligence by forming an approved LMU; 4) how LMU reserves are defined for each lease: 5) the extent to which leases are readjusted on schedule; 6) the extent of effective enforcement of the 1976 regulations by DOI and the Department of Justice; and 7) how many nonproducing leases are relinquished,

Exchanges

Because of requirements in FCLAA that all new leases must be offered by competitive bid, the possibilities for trading new Federal leases for Federal leases where mining poses problems is limited to exchanges specifically authorized by Congress and to leases in alluvial valley floors where mining is prohibited by SMCRA. The congressionally authorized exchanges would offer unleased Federal coal for relinquishment of certain existing leases in Wyoming and New Mexico and PRLAs in Utah, and for contested leases on Indian lands in Montana, Exchanges of non-Federal coal lands in alluvial valley floors that cannot be mined for available Federal coal reserves is also authorized under SMCRA. Generally, to be approved by DOI, the tracts exchanged must be approximately equal in value and the exchange must serve the public interest. Exchanges can thus offset possible losses in coal production from areas that cannot be mined.

Preference Right Lease Applications

Processing of the 176 PRLAs over the next 3 years will confront several legal, administrative, and procedural issues before the potential for coal production from pending applications will be known. Among the questions to be resolved are: 1) how many PRLAs will be affected by conflicting mining claims, 2) how many rejected prospecting permits and PRLAs will be reinstated on appeal, and 3) how many PRLAs will fail to meet the more stringent commercial quantities test for discovery of a valuable deposit. The production potential from PRLAs could range from 35 million to 60 million tons per year in the 1990's, depending on the extent that legal, planning, and environmental considerations affect the issuance of preference right leases. * This is considerably less than earlier estimates made by DOI on production potential from PRLAs but still represents a significant contribution from Western coal in the 1990's.

Areas Unsuitable for Mining

Section 522 of SMCRA allows DOI to designate areas on Federal lands as unsuitable for mining. Two petitions affecting Federal coal have been filed. One petition involving existing leases in southwestern Utah has been decided, In December 1980, the Secretary of the Interior declared 8 percent of the leased surface minable reserves in the Alton area (about 24 million out of 290 million tons) as unsuitable for mining because of ad-

*This range includes about 10 million tons of PRLA production capacity associated with new mines on existing Federal leases. Additional PRLA production is possible from PRLAs in eaStern Colorado and Wyoming if a very strong demand arises for coal that is suitable for synthetic fuels development in the 1990's.

verse impacts on nearby Bryce Canyon National Park. The Secretary found that mining activities would significantly reduce visibility and scenic vistas from park overlooks and increase noise levels in the park, damaging the values for which the park was established and the experience of the park's visitors. The decision has been challenged in Federal court in Utah by both the environmental groups who brought the petition and by the Alton lessees.

The second petition submitted jointly to OSM and the State of Montana involves intermingled Federal, State and private lands in the Tongue River area of Montana, The petition area does not cover any existing Federal leases but does include the non-Federal Montco Mine with a proposed capacity of 12 million tons per year as well as areas under consideration for the 1982 Powder River region coal lease sale.

Transportation Considerations

The two most important modes of transporting Western coal in 1979 were by rail and wire. Railroads originated more than 60 percent of all Western coal production in 1979. Most Federal coal was hauled by rail to utilities. Mine-mouth and other nearby generating plants use locally mined coal and distribute it as electricity through high-voltage transmission lines.

Other transport modes are currently less important to Western coal production. Only one coal slurry pipeline presently operates, It has a 4.8-million-ton-per-year capacity. Trucks handle about 15 percent of Western coal tonnage, mainly for local markets in Utah and Colorado. About 2 percent of Western coal is moved by rail to port terminals on the Great Lakes, and another 4 percent to river connections, About 23 percent was moved by tramway, conveyor, or private railroad.

The Western rail transportation network has the ability to increase its capacity to move coal from mine to market during the 1980's and 1990's. Most Federal coal leases are and will be served by rail. The mine-to-market transportation cost of Western coal ranges from about 10 percent to over 70 percent of delivered fuel costs and constitutes an important factor in determining future demand. The existing rail transportation network in the West was generally adequate to move coal production from Federal leases and private tracts in 1980, although a number of specific bottlenecks have been identified. The principal constraint that might materialize in moving leased coal to its markets is the willingness of the railroads to invest sufficient capital in time to satisfy demand for increased rail service from all shippers, including Federal coal,

Increasing amounts of Federal coal are likely to be burned at nearby powerplants and the electricity transmitted by wire. However, plans for construction of powerplants in the West to export electricity must consider air quality standards, competition for water, and possible opposition to granting of rights-of-way for high-voltage transmission lines. These plants are attractive to utilities which own both the generating plant and distribution system and, thereby, become independent of other carriers. Various studies have reached different conclusions regarding the relative cost efficiency of rail v. wire transportation.

Although coal slurry pipelines have not played a significant role in coal transportation to date, a number of slurry pipelines are planned or proposed. Nearest to construction is the Energy Transportation Systems Inc. line that is planned to ship 25 million tons per year of Powder River basin coal to Oklahoma, Louisiana, and Arkansas. OTA found in an earlier study* that:

> . . . [coal slurry pipelines] . . . do represent under some specific circumstanecs the least costly available means for transporting coal measured in economic terms.

*Office off Technology Assessment, U.S. Congress. Coal Slurry Pipelines, Summary, Washington, D.C., U.S. Government Printing Office, September 1980) p. 8 This summary updates an earlier report. *A Technology Assessment of Coal Slurry Pipelines* (Washington. 1). C.: U S Government Printing Office, March 1978).

This report also stated that:

> . . . the introduction of coal slurry pipelines is not likely to affect materially the rate of coal resource development and use on a national scale. It may, however, affect the regional pattern of coal mining and distribution in such a way as to expand the use of Western coal to greater distances from its area of origin,

Revenues and Socioeconomic Considerations

Energy development, including recent large-scale coal mining, has frequently brought rapid growth to Western rural towns. Many communities have been hard pressed to deal with the sudden influx of people. Typically, they have found themselves short of housing, municipal services, health care facilities, and other elements of an extensive community infrastructure. Some towns have shown symptoms of social disruption, such as increased crime, alcoholism and suicide, and of economic dislocation, such as local business failures and labor shortages.

The communities have had varied degrees of success in coping with these boomtown problems. Mitigation is complicated because it is hard to anticipate which towns are apt to have severe difficulties. Both public and private sectors are engaged in preventive efforts; industry actively participates because successful mitigation helps stabilize its work force.

The ability to solve the problems is hampered by a lack of timely revenues; expanded facilities and services are needed before new local taxes are available, Planning and construction must start in the early stages of rapid growth, but this is before mines or other industries come on the local tax rolls. Several ways have been used to meet the early costs. These include State revenue mechanisms, such as severance taxes, and private contributions, such as the prepayment of taxes. The States' share of Federal mineral leasing revenues can be used, but these payments do not increase substantially until coal is produced. Consequently, State and local governments have looked to other Federal programs for assistance.

Each Western State (except Alaska) receives 50 percent of the revenues from mineral leases of public lands in the State. These funds are distributed according to priorities set by each State legislature. Section 10 of FCLAA directed OTA to provide an estimate of future rentals and royalties from existing Federal coal leases. Based on potential production and expected coal prices for each region, OTA has derived estimates for 1986 and 1991. Table 5 shows the current allocation and estimates by State. The estimates indicate a substantial increase over the amount

Table 5.— Federal Royalties and State Distributions From Potential Coal Production on Federal Leases 1980 (actual), 1986, and 1991 (estimated)

	1980[a]			1986[b]			1991[b]		
State	Federal lease production (millions of tons)	Royalty total (millions of dollars)	State share (millions of dollars)	Federal lease production (millions of tons)	Royalty total (millions of dollars)	State share (millions of dollars)	Federal lease production (millions of tons)	Royalty total (millions of dollars)	State share (millions of dollars)
Colorado	9.4	8.9	4.5	27	49	24	33-40	78-94	39-47
Montana	10.4	2.7	1.3	23-31	21-27	10-14	25-40	23-37	12-19
New Mexico	6.3		3.5	9-11	15-16	7-8	12-16[c]	21-28[c]	11-14C
North Dakota	0.6	(0.3)	0	about 6	about 4	2	6	5	2
Utah	8.7	4.5	4.4	26	48	24	34-66	64-122	32-66
Wyoming	33.4			113-150	57-71	28-36	133-238	145-258	73-129
Total (West)	68.8	31.5	16	204-250	193-215	95-108	245-405	336-544	168-277

Details may not add to totals because of independent rounding.

[a] U.S. Department of the Interior, Geological Survey, Conservation Division Federal and Indian Lands, Coal, Phosphate, Potash, Sodium, and Other Mineral Production, Royalty Income, and Related Statistics, Calendar Year 1980 (June 1981).

[b] Royalty estimates assume timely readjustment of leases to a minimum royalty of 125 percent for surface coal and 8 Percent for underground coal

[c] Excludes about 8 million tons of Federal PRLA production and about $15 million in PRLA royalties.

SOURCE: Off Ice of Technology Assessment.

of revenues distributed in 1980, These revenue increases come primarily from expanded Federal production and readjustments to the higher royalty rates required by FCLAA,

There is, however, considerable debate over whether existing private and governmental programs will be adequate to meet the financing and other needs arising from the management of energy development growth. Federal coal development in the 1980's, especially in areas where other kinds of rural industrialization (such as synfuels and powerplant development) are occurring, could strain the capacities of communities in the Powder River basin, the western slope of Colorado, central and southern Utah, and the San Juan basin of New Mexico.

CHAPTER 2

Background and Introduction

Contents

CHAPTER 2

Background and Introduction

The Federal Government owns between 50 and 60 percent of the coal reserves west of the Mississippi River. Over 16 billion tons of these Federal reserves are currently under lease, * In 1979, coal production from leased Federal land was about 60 million tons. As Western coal production expands to meet new demand, the development of Federal leases will become increasingly important.

Since 1920, the Department of the Interior (DOI) has administered a leasing program that allows the private sector to mine coal on Federal lands, A lease grants to the lessee the exclusive right to mine coal subject to the terms of the lease and to State and Federal laws. Historically, leases have been issued by two methods; 1) competitively, to the highest bidder at a lease sale and 2) noncompetitively, through an application process called "preference right leasing, " to prospectors who discovered commercial coal reserves on Federal land, About half of all existing leases have been issued by each method. The Federal Coal Leasing Amendments Act of 1976 (FCLAA), which abolished the preference right system, requires competitive leasing of Federal coal.

In 1970, a Bureau of Land Management (BLM) study of the Federal coal leasing program found that from 1955 to 1970 the amount of coal under lease had increased sharply while the amount of production from Federal leases had declined. (See fig, 15 in ch. 3,) In response to this study, BLM imposed an informal moratorium in 1971 on the issuance of new leases. The purpose of this moratorium, which was made formal in February 1973, was to provide time to reassess Federal coal leasing policies. Over the next several years a number of issues were examined during BLM's reassessment of the size, timing, and location of new leasing.

*See ch. 4 anti table 7 for a discussion of the amount of Federal coal reserves in the West.

Public concern and debates about these issues and about the structure and management of the leasing program led to congressional hearings and to passage of FCLAA (Public Law 94-377). Section 10 of this act directs the Office of Technology Assessment to conduct an independent review of existing Federal coal leases. Specifically, the act directs OTA to:

- analyze all mining activities on Federal coal leases;
- determine the present and potential value (production) of Federal coal leases;
- estimate the Federal receipts from lease rentals and royalties: and
- assess the feasibility of using deep-mining technology in leased areas.

To meet these requirements, OTA completed a comprehensive inventory of Federal coal leases, which identifies the location of each lease, its major geotechnical characteristics (e.g., amount and quality of coal, depth and thickness of the coal seams), and the business experience and capability of the lessee. After completing this inventory, OTA analyzed the development potential and production prospects of the 565 Federal coal leases in existence on September 30, 1980. * OTA estimated the mine design capacity and annual production that these leases could sustain from 1980 to 1991, considering the mining and reclamation conditions anticipated on the leases and the market conditions, environmental, transportation, legal, and institutional factors affecting their development. In addition, OTA analyzed the prospects for increasing coal recovery by underground methods on Federal leases and estimated the revenues from present and potential production.

*The study does not examine unleased Federal coal or the leases issued in early 1981 as part of the new leasing program of the Department of the Interior.

Scope of the Assessment and Methodology

There are currently 565 Federal coal leases and over 170 pending preference right lease applications (PRLAs) in 14 States. This report focuses on the leases in Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming. These seven States account for 97 percent of the existing leases and over 99 percent of the leased recoverable reserves (16.5 billion tons). OTA did not examine the development potential and production prospects of unleased Federal coal reserves, proposed new leasing tracts, or the small quantity of reserves under lease in Alabama, Alaska, California, Kentucky, Oregon, Pennsylvania, and Washington.

Coal leases in this report are classified according to their mine plan status on September 30, 1980. Submittal of a mine plan is an important milestone in lease development. DOI must approve a mine plan before a lessee can mine coal from Federal land. Each mine plan details the development plans of the lessee, includes technical information on the resource characteristics of the lease(s), and describes the proposed mining operation. Accordingly, OTA grouped the leases in three categories of development: 1) leases with approved mine plans; 2) leases with mine plans submitted and pending approval; and 3) leases with no submitted mine plan. Leases without mine plans are called "undeveloped" leases in this report.

Evaluation of the development potential and production prospects of existing Federal coal leases and PRLAs involved extensive data collection and analysis. Development and production of Federal coal will depend on a variety of property characteristics, including: 1) the quantity and quality of reserves, 2) the geological features of the coal deposits, 3) the size and configuration of the leases (coal leases vary from 40 acres to more than 20,000 acres and are often interspersed with non-Federal coal), and 4) environmental, mining, and reclamation conditions. The mining experience and capital resources of the lessee are also important to consider in estimating the development potential and production prospects of a lease. The production prospects of many Federal leases will also depend on other factors including the level of demand and location of markets for Western coal, the impacts of State and Federal policies and regulations, and the availability of transportation.

Information Sources

OTA obtained information from a variety of sources, including: 1) Federal and State government agencies; 2) special studies; and 3) interviews and special State task forces.

Federal and State Government Agencies

In addition to the mine plans submitted by the lessees and the lease records, two important sources of technical data used in this study, especially for the analysis of undeveloped leases, are the Automated Coal Lease Data System (ACLDS) and the information submitted by lessees under General Mining Order No. 1 (GMO No. 1).

ACLDS is a computer-based inventory of Federal coal leases and lease applications. The system is managed by BLM and is updated every 6 months. The purpose of ACLDS is to store in a readily accessible format a range of technical and administrative information on every existing lease. The system is still being developed and both the quality and amount of information vary among leases. The U.S. Geological Survey (USGS) is currently revising the reserve information for each lease in ACLDS, integrating the information on mining methods and conditions acquired by USGS officials and geophysical data from its files with data prepared under contract and with each lessee's submittal under GMO No. 1.

GMO No. 1 establishes a standard procedure for estimating in-place, minable, and recoverable reserves. The order also requires the lessee to submit other information on a lease such as overburden thickness, stripping ratio, and seam thickness according to uniform reporting criteria. GMO data are reviewed and processed in regional offices of USGS. Because there are differences in the interpretation of this data among USGS offices, the process of developing a uniform, comprehensive data base for Federal coal leases is still continuing. When GMO data were not available, OTA was often able to obtain information on coal reserves from the lessees themselves or from regional environmental impact statements (EISS), other published sources, or independent calculations.

Special Studies

In addition to reviewing numerous published and unpublished reports on Western coal development and Federal coal leasing, OTA conducted several special studies to support the assessment, These include:

- Ownership study, Analysis of ownership trends of Federal coal leases that identifies and classifies the types of business organizations that have acquired Federal coal reserves from 1950 to 1980.[1]
- PRLA study. Review of the history of preference right leasing, the location of existing PRLAs, and the ownership patterns and business organizations of the holders of PRLAs.
- Mine development study. Review of the major geotechnical and economic features of coal mining in the seven Western States covered in this assessment. "Mine profiles" are developed for each region.
- Market studies, Analysis of the likely markets for coal produced in Wyoming, Montana, Colorado, and Utah, and of the factors that are expected to affect demand for this coal in the 1980's.
- Synthetic fuels study. Analysis of the coal quality requirements an-d technical issues affecting potential development of coal-based synthetic fuels projects in the Western United States.

Interviews and Task Forces

OTA conducted personal and telephone interviews with representatives of coal companies, industry associations, Government agencies, and technical and policy specialists. OTA also convened five State task forces to assess the development potential of undeveloped Federal leases in Colorado, New Mexico, Oklahoma, Utah, and Wyoming and to review the factors affecting coal development in these States. These task forces brought together participants from Federal and State government agencies, industry, environmental groups, and the general technical community. * The results of task force deliberations contributed to the six OTA State reports, which assessed the development and production prospects of undeveloped leases and analyzed the factors affecting Federal coal development in each of the seven States.**

[1]This study has been published as an OTA Technical Memorandum, Patterns and Trends in Federal Coal Lease Ownership, 1950-80, OTA-TM-M-7, March 1981.

*A complete listing of the task force participants is at the front of this report.

**Six State reports were prepared. Reports on the undeveloped leases were prepared for: 1) Wyoming and Montana; 2) Colorado; and 3) Utah. Reports for North Dakota, Oklahoma, and New Mexico were also prepared, covering both developed and undeveloped leases. These reports will be available through the National Technical Information Service.

Analysis of Leases in Mine Plans

The primary source of information used to estimate potential production for leases in approved or pending mine plans was the mine plan itself.

Some of the important mine plan data reviewed by OTA include:

- quantity and quality of the reserves, total permitted and total disturbed acreage, seam thickness, and depth of overburden;
- mining and reclamation methods, permit requirements, and pending regulatory actions;
- mine design, anticipated resource recovery rates, peak capacity of the mine, and the lessee's estimated annual production from 1981 to 1990.

After reviewing this information, OTA prepared a summary of each mine plan that identifies the location, size, and type of the mining operation; the Federal leases, and the State and private lands in the mine plan or contiguous with or close to the mining area; surface ownership; and the quality and quantity of the coal reserves.

The summary also identifies the geological, environmental, and mining conditions that could potentially increase or decrease the recoverability of the coal reserves at the mine. The summary also considers the completeness of the mining plan, the status of geological exploration and monitoring activities completed at the site, and access to transportation networks.

The quality and amount of the information contained in the mine plans, and the range of issues they covered, vary considerably. Some of the mine plans exceed 20 volumes. Many provide a great deal of information on the environmental factors discussed in this report, especially those pertaining to reclamation. Comprehensive technical and environmental assessments prepared by the Office of Surface Mining (OSM), and technical and policy memoranda prepared by OSM and USGS during the mine plan review are also included in the official Government files on many of the larger mine plans, along with contractor reports and correspondence between lessees and Government officials. *

*A few leases in mine plans that were incomplete or inactive or submitted after August 1980 were included in the assessment of undeveloped leases.

Analysis of Undeveloped Leases

Nearly 45 percent of the existing Federal coal leases (249 leases) are not covered by approved or pending mine plans. For these undeveloped leases, detailed descriptions of the lessee's development plans are not readily available. State task forces were convened to assist in assessing the development potential and production prospects of these undeveloped leases. Task forces were held in Colorado, New Mexico, Oklahoma, Utah, and Wyoming.

Before each task force, OTA conducted a preliminary evaluation of the development potential of the undeveloped leases in the State. All adjoining undeveloped leases held by the same lessee and forming a compact and contiguous geographic unit were combined into a single lease block for purposes of analysis. The property characteristics of the lease blocks were then compared with a profile of economically viable mines in the State. (Mine profiles for average new mines were developed for each Western coal basin with Federal leases.) The following questions were asked in the comparison:

- Mining unit. Is the lease block compact, contiguous, and under single ownership to allow for orderly development as a mining unit?

- *Coal reserves.* Are there enough recoverable coal reserves within the lease block to support a competitive new mining operation?
- Coal quality. Do the coal reserves meet minimum Btu, sulfur, and ash quality standards for the expected end use (e.g., electric power generation, industrial use, synthetic fuels)?
- *Geological characteristics.* Do the geological and topographical conditions of the coal reserves—such as depth of overburden, seam thickness, and dip—permit economic coal recovery?
- Ownership. Does the lessee have the financial capability and mining expertise to develop the lease block?

The task force members drew on their extensive experience and knowledge of local conditions to assess the influence of other factors on the development potential of the leases, including potential markets, geographic location, status of adjacent properties, surface resource values, transportation availability, community infrastructure, and environmental impacts. Following this review, OTA, with the assistance of the State task forces, classified the lease blocks as having:

- Favorable development potential.—The lease or lease block has favorable development characteristics overall; the lease(s) meet the threshold criteria for a viable mining property; there are no identified major technical or permitting problems or uncertainties associated with the lease development.
- Uncertain development potential.-The lease or lease block has uncertain development potential because development is contingent on factors such as transportation or synfuels development or because of lack of information about the lessee's development intentions. Property characteristics can be good or marginal.
- Unfavorable development potential.—The lease or lease block has unfavorable development potential, generally because it has one or more of the following property characteristics: small reserves, difficult mining or reclamation conditions, poor quality coal, or isolated location.

Finally, each State task force estimated the production prospects for all undeveloped leases with either uncertain or favorable development potential. The results of each task force were reviewed by OTA and supplemented with additional information where needed.

Analysis of Diligent Development

The **1920** Mineral Leasing Act originally provided that a Federal lease be issued for an indeterminant period of time, subject to the requirement that the lease be diligently developed. The act also included a clause requiring continuous operation after the lease was brought into production. Failure to abide by these conditions was grounds for cancellation of the lease. Between 1920 and 1970, however, the diligence requirements for Federal coal leases were not specifically defined. No lease was ever canceled because it failed to meet diligence. In **1976,** FCLAA removed the indeterminate term for Federal leases and required that new leases be canceled if they do not produce coal in commercial quantities within 10 years of issuance. Also in 1976, DOI issued regulations specifying that 2½ percent of the recoverable reserves on leases issued before the passage of FCLAA (pre-FCLAA leases) must be mined by June 1, 1986, to fulfill the terms of diligent development and that 1 percent of the recoverable reserves on leases issued after August 4,

1976 (post-FCLAA leases) must be mined 10 years after the date of issuance. Continuous operations requirements were also specified.

Under the 1976 regulations, the Secretary of the Interior can grant up to a 5-year extension of the 1986 deadline for pre-FCLAA leases. (Post-FCLAA leases are not eligible for this 5-year extension.) The grounds for granting an extension are: 1) time needed to complete the development of an advanced technology such as synthetic fuels, 2) time needed because of the magnitude of the project such as a large mine, or 3) a contract for sale of the first 2½ percent of the lease reserves after 1986. In addition to the above reasons, lease terms can be suspended because of delays in meeting the diligence requirements that are beyond the control of the lessee (e.g., accidents, strikes, or administrative delays). Poor market conditions do not constitute grounds for suspending the lease terms or extending the deadline for diligence.

In light of the diligence requirements promulgated in the 1976 regulations, 2 years are particularly important in OTA's analysis of Federal coal development: 1986 when leases issued prior to August 4, 1976, must meet the diligent production requirement of 2½ percent of the recoverable reserves, and 1991 when those pre-FCLAA leases that have been granted a 5-year extension must produce 2½ percent of the recoverable reserves. OTA analyzed its estimates of future production from Federal coal leases to determine how many leases are likely to meet diligence by 1986 or by 1991. *

Patterns of coal ownership in the West are not always consistent with the most efficient and economical mine design. Often a mine will include coal that is owned by the Federal Government, by a State Government, or by a private party. In recognition of this possibility and to promote the economical and efficient development of Federal coal leases, the concept of logical mining unit (LMU) was included in FCLAA and the 1976 regulations. An LMU is defined in the FCLAA as "an area of coal land that can be developed and mined in an efficient, economical and orderly manner with due regard for the conservation of coal reserves and other resources." According to the regulations, no LMU may be larger than 25,000 acres. All areas within an LMU must be contiguous and under the control of a single operator.

LMU is an important concept in this report because it defines the physical boundaries within which recoverable reserves are identified for diligence requirements. By regulation, BLM has defined every lease as an LMU whether or not it meets the statutory LMU description. Therefore, unless a lessee requests that a lease be included in an LMU with other Federal leases or non-Federal coal, the recoverable reserves on a lease will establish the reserve base on which diligent production requirements will be calculated.

In cases where a lease is included in an LMU with other Federal leases or non-Federal coal, compliance with diligent development and continued operations requirements will be calculated on the total recoverable reserves in the LMU, not just the Federal reserves. Consequently, a Federal lease in an LMU with non-Federal coal could meet diligence requirements before any Federal coal is mined, and in any year could fulfill continuous operations requirements even if no coal were mined from the lease itself. Under certain circumstances a lessee may petition to relinquish certain areas of the lease or certain seams or beds, in order to lower the recoverable reserves so that diligent development can be achieved.

*Of the 565 Federal coal leases in existence as of Sept. 30, 1980, less than 40 are post-FCLAA leases. Almost all of these post-FCLAA leases are associated with active mines and will meet diligence by or before their due date as part of the larger mining operation.

Uncertainties in the Analysis

OTA's analysis draws on extensive geological, technical, and market data, and informed judgments about the development potential and production prospects of Federal coal leases made by OTA and the OTA task forces on the basis of these data. Many of these judgments were reviewed by the lessees and by technical specialists. Nevertheless, uncertainties remain in the analysis both of leases in mine plans and of undeveloped leases.

Many undeveloped leases with good property characteristics, with owners actively developing the property, and with markets identified and, in some cases, with signed contracts are likely to be producing coal in the next 10 years. There is little uncertainty in ranking many of these leases as having favorable development potential and production prospects.

Many of the undeveloped leases classified as having unfavorable development potential have poor property characteristics compared to mines currently operating in the area and would be expensive to bring into production. Small reserves, poor coal quality, difficult mining and reclamation conditions, or combinations of several of these factors mean that there is little uncertainty in classifying these leases as having unfavorable development potential. However, even for some of the undeveloped leases with poor property characteristics, the lessee might be able to integrate the lease into an operating or planned mine or develop the lease for synthetic fuels production. Consequently, several undeveloped leases with poor property characteristics have favorable or uncertain development potential.

The development potential of many other undeveloped leases was clouded by uncertainties, In several cases, lease development was dependent on factors such as a favorable climate for synfuels or the construction of a new transportation facility.

Markets and the demand for Western coal over the next 10 years were particularly important considerations for those undeveloped leases with favorable or uncertain development potential. Coal production in the West during this period will likely be demand driven. OTA assessed the potential demand for coal from States with major Federal coal reserves. However, demand projections for Western coal are subject to numerous uncertainties, ranging from the rate of increase of electricity demand to the amount of coal to be exported to foreign countries. Moreover, even if demand for Western coal could be accurately and precisely forecast, predicting the success of a given lessee in capturing a share of this demand would still be subject to uncertainty. In the buyer's market that is likely for Western coal in the next 10 years, there will be strong competition for new sales, including competition from non-Federal coal mines in the West, from new Federal leases, and from coal produced in other regions. A number of factors, but especially the marketing success of the lessee, will ultimately decide whether or not a given undeveloped lease is brought into production and at what level. Even for those leases in approved mine plans with definite production goals and in many cases with contracts, the amount of coal that will be mined annually over the next 10 years is subject to uncertainty.

Thus, the estimates of potential production from Federal leases made in this report are not forecasts of the coal that would be produced at a given price or a given demand. They are estimates of the total amount of coal that could be produced from operating and proposed Federal mines and from those undeveloped Federal leases that have characteristics comparable to operating mines in the same region. Coal from these leases would thus be likely to have mining costs competitive with costs at currently operating mines in the same area. If the demand for Federal coal does not increase to these levels of potential production, then not all the Federal leases that could technically and economically be developed will be brought into production. Moreover, although OTA based its evaluations of likelihood of development and levels of potential production on the best data available for each lease or mine at the time, as additional information based on further exploration and development becomes available, the prospects for any given lease or mine could change.

Estimating production from Federal leases was complicated by the fact that many coal operations in the West include Federal, State, or private (fee] coal. This pattern is most pro nounced in southern Wyoming, the Colstrip area of the Montana portion of the Powder River basin, and in North Dakota. For North Dakota, Wyoming, and Montana, OTA has estimated what fraction of the annual production of mines with Federal leases is likely to be from Federal reserves. In many cases, the geological characteristics of the mine and the direction of mining operations are such that little variation occurs from year to year in the ratio of Federal to non-Federal production; in other cases, however, large changes in this ratio will occur over several years. Wherever possible, OTA followed the judgments of the lessee's mine plan.

In any work that evaluates a large number of units, random statistical errors and changes tend to cancel one another. While events could prove OTA's estimates of lease development wrong in a number of individual cases, taken in the aggregate by region or State, the estimates presented in this report should constitute a reasonably accurate picture of Federal coal development over the next decade.

Focus of Subsequent Chapters

Chapters 5, 6, and 7 present OTA's findings concerning the development potential and production prospects of Federal coal leases. Chapter 5 identifies the factors that are likely to affect the markets for Western coal over the next 10 years and reviews the demand projections for Western coal that have been developed and considered by industry and Government. Chapter 6 presents the findings of the assessment on the amount of Federal coal that is likely to be produced over the next 10 years and the number of leases likely to fulfill diligence requirements. Chapter 7 is a case study of Federal coal development and production in the Powder River Basin of Wyoming and Montana.

Chapters 3, 4, and 13 review the status, distribution, geotechnical characteristics, and ownership of existing Federal coal leases, Federal coal reserves, and PRLAs. Chapters 8, 10, and 12 examine the impacts on Federal coal development and production resulting from transportation availability and costs, environmental statutes and regulations, and socioeconomic factors. Chapter 12 also presents OTA's estimate of revenues from rentals and royalties from Federal coal production over the next decade. Chapter 9 provides an overview of Federal coal lease management issues, and chapter 11 presents OTA's analysis of the feasibility of increasing Federal coal recovery through underground mining methods.

CHAPTER 3

Federal Coal Leases and Preference Right Lease Applications: An Overview

Contents

List of Tables

List of Figures

CHAPTER 3

Federal Coal Leases and Preference Right Lease Applications: An Overview

As of September 30, 1980, there were 565 Federal coal leases in 14 States (see table 6]. Ninety-seven percent of the total, or 548 leases, are located in seven Western States: Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming. These 548 leases were examined by OTA in some detail. * Utah has 204 or 36 percent of all leases, more than any other State, Colorado and Wyoming have the next largest number of leases, 127 (22 percent) and 101 (18 percent) respectively, With 20 leases, North Dakota has the fewest leases among the seven States studied by OTA.

*OTA did not examine coal leases that have been relinquished or canceled and made only a limited review of leases outside this seven State region because of the small reserves involved. OTA did not study unleased Federal coal.

Table 6.—Extent of Leasing
(includes all leases in existence as of Sept. 30, 1980)

	Number of leases	Acreage under lease	Recoverable coal reserves (billions of tons)
Colorado	127 (22%)[a]	126.893 (16%)	2.2 (13%)
Montana	21 (4%)	37,286 (5%)	1.2 (7%)
New Mexico	29 (5%)	44,760 (6%)	0.45 (3%)
North Dakota	20 (4%)	18,692 (2%)	0.27 (2%)
Oklahoma	46 (8%)	74,046 (9%)	0.2 (1%)
Utah	204 (36%)	279,496 (34%)	3.2 (19%)
Wyoming	101 (18%)	217,273 (27%)	8.9 (54%)
Other States	17[b] (3%)	13,555 (2%)	0.07 (0.4%)
Total	565 (100%)	812,001 (100%)	16.5 (100%)

[a]All percentages are percent of total leasing, sums may not add to 100 Percent because of rounding.
[b]The "other" leases include leases in Alabama (2), Alaska (4), California (1), Kentucky (3), Oregon (3), Pennsylvania (2), and Washington (2)

SOURCE Off Ice of Technology Assessment,

The 565 coal leases cover 812,000 acres of Federal land, 7 percent of the 11.5 million acres of Federal coal land classified as known recoverable coal resource areas (KRCRA) as defined by the Department of the Interior (DOI) in March 1978. Utah, Wyoming, and Colorado have a major proportion of leased acreage with 34, 27, and 16 percent respectively. North Dakota has the fewest leased acres among the seven principal States studied.

OTA estimates that 16.5 billion tons of recoverable coal reserves are now under lease in the seven States with 97 percent of the leases. Production from these reserves totaled 60 million tons in 1979 and 69 million tons in 1980; in the same years, total U.S. coal production was 776 million tons and 820 million tons, respectively.

Currently leased Federal reserves are less than 20 percent of the estimated total of over 80 billion tons of Federal recoverable coal reserves (see table 7). The percentage of total Federal coal reserves under lease in each State varies from a high of 50 percent in Utah to a low of 5 percent in Montana and about 3 percent in North Dakota. The percentages of federally owned coal to the total known recoverable coal reserves in each State vary from under 10 percent in Oklahoma to 85 percent in Utah with an average of about 60 percent for the seven States. *

Leases range from 40 acres to 20,701 acres. Approximately 60 leases are under 100 acres and 4 leases are over 10,000 acres in size. In terms of recoverable coal reserves, some small leases contain negligible amounts of coal (i. e., under 10,000 tons) while several large leases contain over one-half billion tons of recoverable coal.

*These percentages represent best available data on coal reserves and ownership, but these data are incomplete. See footnotes to table 7.

Table 7.—Leased, Federal, and Total Recoverable Coal Reserves in the Principal Western Coal-Producing States (all reserves shown in billion tons)

	Recoverable coal under lease[a]	Estimates of total Federal recoverable reserves[b]	Estimates of total recoverable coal[c]
Colorado.	2.2	10	17
Montana	1.2	26	40
New Mexico . .	0.45	4	9
North Dakota .	0.3	-10	25 to 35
Oklahoma. . . .	0.2	0.2	2
Utah	3.2	6.4	7.5
Wyoming	8.9	26	36
Total	16.5	-83	-140

[a]Leased reserve figures from Automated Coal Lease Data System as modified by Office of Technology Assessment.

[b]The numbers in this column are estimates of the total Federal recoverable coal reserves in each State. The figure for New Mexico was supplied to Office of Technology Assessment by the New Mexico Bureau of Mines and Mineral Resources and the figure for Utah by the Utah Geological and Mineral Survey. See footnote c, below. The figures for the other states were estimated by multiplying the estimate of total recoverable coal in the State by the percentage of Federal coal acreage in Known Recoverable Coal Resource Areas in each State These percentages were taken from table 21 in ch. 4 and are: Colorado (580/0), Montana (640/0), North Dakota (327.), and Wyoming (730/0). In Montana, the Federal percentage may be high because the KRCRAs do not include Indian reservations with significant reserves of coal. The Colorado percentage may also be high because the KRCRAs do not include the Denver-Raton Mesa coal region which has a high percentage of non-Federal coal ownership.

[c]Total State recoverable reserves from the following sources:

Colorado. Keith Murray, Colorado School of Mines Research Institute. Personal communication to Office of Technology Assessment, February 1981. The figure of 17 billion tons is based on his earlier work at the Colorado Geological Survey.

Montana: Montana Bureau of Mines and Geology as reported in the 1979 *Keystone Coal Industry Manual.* The figure of 40 billion tons was derived from the reported figure of 50 billion tons of strippable reserves and a recovery rate of 80 percent. This figure does not include 71 billion tons of underground demonstrated reserve base also listed in the 1979 *Keystone Coal Industry Manual* from data supplied by the U.S.B.M.

New Mexico: New Mexico Bureau of Mines and Mineral Resources, Personal communication to Office of Technology Assessment, August 1981. The figure does not include an additional 59 billion tons of recoverable underground reserves between 250 ft depth and 3,000 ft depth because insufficient information was available for the New Mexico Bureau to determine the portion of these reserves in seams that are likely to be mined In the next decade.

North *Dakota:* North Dakota Geological Survey, Personal communication to Office of Technology Assessment, August 1981. A recovery rate of 90 percent has been assumed by the North Dakota Survey.

Oklahoma: Friedman, S.A. *Investigation of the Coal Reserves in the Ozarks* Section of Oklahoma and their Potential Uses (Norman, Okla.: Oklahoma Geological Survey, 1975).

Utah: Utah Geological and Mineral Survey, Personal communication to Off Ice of Technology Assessment, August 1981. The Utah Survey cautions that this figure is low, because it is based on stringent standards for identification and correlation of economically recoverable reserves.

Wyoming: Gary Glass, Wyoming Geological Survey, Personal communication to Office of Technology Assessment, August 1981. The above figure is derived from a surface reserve base of 26.3 billion tons with a recovery rate of 80 percent and an underground reserve base of 29.5 billion tons with a recovery rate of 50 percent. Glass cautions that the underground recovery rate of 50 percent may be too high for Wyoming.

General caution: The total recoverable coal reserve figures were obtained from seven different sources and are not based on uniform standards.

SOURCE: Office of Technology Assessment.

History of Leasing

Federal coal has been leased since enactment of the Mineral Leasing Act on February 25, 1920. The oldest lease still in effect, issued on January 17, 1921, originally covered 2,080 acres in Utah. Of the currently existing leases, 88 were issued before 1950 (see table 8). These include 16 percent of all existing leases, but only 5 percent of all land under lease as of September 30, 1980. Eighty-six percent of all leases covering 90 percent of all land under lease are at least 10 years old. *

*A total of 526 of the 565 existing leases were issued before Aug. 4, 1976, the date of enactment of the Federal Coal Leasing Amendments Act of 1976 (Public Law 94-377]. Technically these are the "existing" leases subject to OTA scrutiny under sec. 10 of that law.

The number of leases and leased acreage increased slowly in the 1950's but accelerated sharply in the 1960's (see fig. 15). The solid line (number of leases) and the dashed line (acres under lease) in figure 15 cross around 1965 because of a trend during the 1960's to include larger acreages in single leases. The moratorium on most new leasing by DOI from 1971 through 1980 slowed leasing to the levels of the 1950's.

Historically, trends in Federal coal production did not coincide with trends in leasing. Production declined from 7.1 million to 5.4 million tons from 1950 to 1960 and remained at this relatively low level during the 1960's. Production during the 1970's has, however, soared from 7.3 million tons in 1970 to 69 million tons in 1980.

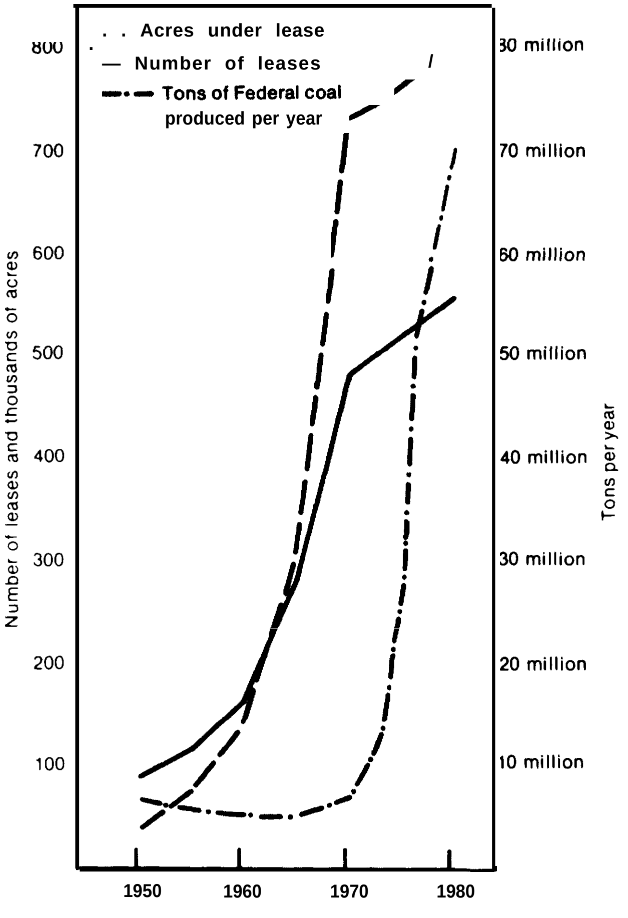
Table 8.— History of Leasing 1950-80[a]

	Number of leases		Acres under lease	
1950	88	(16%)[b]	41,492	(5%)
1955	119	(21 %)	75,949	(9%)
1960	166	(29%)	143,746	(18%)
1965	286	(51%)	308,354	(38%)
1970	485	(86%)	733,318	(90%)
1975	523	(93%)	764,994	(94%)
1980	565		812,001	

[a]Table includes only leases in existence on Jan 2 of each year listed 1950-75 and which were still valid on Sept. 30, 1980 The 1980 figures report all leases in existence on Sept. 30, 1980
[b]percentages are percent of 1980 totals.

SOURCE Office of Technology Assessment

Figure 15.— Number of Leases, Acreage Under Lease, and Federal Coal Production From 1950 to 1980



SOURCE Acreage and number of leases data from OTA review of DOI case files Federal coal production from the U S Department of Interior, *Federal Coal Management Report* Fiscal Year *1978,* March 1979 and from the ACLDS

Lease Issuance Methods

Existing leases were issued by one of three methods: 1) competitive bidding at a lease sale, 2) noncompetitive preference right leasing, or 3) segregation of an existing lease (also called partial assignment).

The Mineral Leasing Act of 1920 requires DOI to lease competitively public land known to contain commercial quantities of coal, Several bidding procedures have been used in the past, including sealed written bids and open verbal auctions. Leases have been awarded to the party offering the highest one-time cash bonus payment. Other bidding methods besides the cash bonus procedure may be used for future leasing. Although these lease sales were open to all bidders, more than half of all lease sales held before 1979 attracted only one bidder. In total, 52 percent of all existing leases have been issued under the lease sale method (see table 9).

Preference right leasing under the 1920 leasing act was limited to land without known commercial quantities of coal for which additional prospecting work was needed to determine the existence of economically minable coal deposits. In these cases, applicants could receive a prospecting permit from DOI to perform exploration and drilling. If coal was found in commercial quantities within the 2-year permit period (extendable once), the prospector was entitled to a preference right lease. As an incentive to promote exploration of public lands, no bonus was required on preference right leases. Of all existing leases, 42 percent were issued under the preference right method.

In 1971, DOI suspended issuance of new prospecting permits and delayed processing

Table 9.—Lease Issuance Method for Existing Leases

Issuance method	Number of leases	0/0 of leases
Lease sales	294	520/o
Preference right	237	420/o
Segregation	34	60/0

SOURCE Off Ice of Technology Assessment

of pending preference right lease applications (PRLAs). In 1976, in the Federal Coal Leasing Amendments Act, Congress repealed provisions for preference right leasing, subject to valid existing rights. The preference right program no longer exists except for the applications for leases based on the prospecting permits issued prior to the 1971 leasing moratorium (nearly all dating from 1967 to 1971). Applications for leases were not completely processed by DOI when the moratorium began; processing largely ceased during the moratorium and resumed in late 1979. (About 176 applications remain.) These PRLAs are discussed in more detail in the next section.

Another leasing procedure is called segregation or partial assignment. Here, an existing lease is divided into two or more parcels at the request of the lessee(s). Such actions require the approval of DOI. A new lease(s) is then issued for the new tract(s) and the terms of the surviving lease are modified to reflect a reduced acreage. Only 6 percent of outstanding Federal leases have been created by segregation.

Pending PRLAs

As of January 1, 1980, there were 176 pending applications for preference right leases. They stem from prospecting permits issued between 1955 and 1971—with 172 (98 percent) originating after January 1, 1965. These permits expired just before or shortly after the initiation of the leasing moratorium in 1971 and the resulting lease applications were neither approved nor denied. They have remained unprocessed for a decade, although they have been the subject of lawsuits, Government studies, and congressional actions.

Nearly 98 percent of the PRLAs are located in the seven Western State region studied by OTA (see table 10). The remaining four are in Alaska. In total, 403,800 acres of Federal coal land are included in PRLAs and involve an estimated 5.8 billion tons of recoverable coal reserves. Wyoming, with 74 PRLAs, has the largest number of applications. They include 43 percent of the reserves and 34 percent of the acreage in all PRLAs. Colorado ranks second with 37 PRLAs including 18 percent of total reserves and New Mexico is third with 28 PRLAs including 26 percent of the reserves.

Table 10.—Extent and Location of PRLAs

	Number of PRLAs	Acreage	Recoverable coal reserves (billions of tons)
Colorado	37 (21%)[a]	82,923 (21%)	1.0 (18%)
Montana	4 (2%)	14,673 (4%)	0.3[b] (6%)[b]
New Mexico	28 (16%)	77,600 (19%)	1.5 (26%)
North Dakota	0 (0%)	0 (0%)	0 (0%)
Oklahoma	4 (2%)	5,956 (1%)	b
Utah	25 (14%)	75,598 (19%)	0.4 (6%)
Wyoming	74 (42%)	139,210 (34%)	2.5 (43%)
Alaska	4 (2%)	7,840 (2%)	0.1 (1%)
Total	176	403,800	5.8

[a]All percentages equal percent of total for all PRLAs.
[b]Figures for Montana and Oklahoma combined.

SOURCE: Number of PRLAs and acreage from OTA review of DOI case files. Reserves from Automated Coal Lease Data System, Sept. 30, 1979 and reported in U S. Department of the Interior, *Federal Coal Management Report,* March 1980.

Acreages and reserves under the PRLAs are substantial. If all the applications are approved and converted to leases, total land under lease will increase by 50 percent and leased recoverable coal reserves will be raised by 35 percent.

Most of the legal and administrative problems preventing the processing of the PRLAs have been resolved in recent years. The current Federal coal lease management program adopted by DOI in July 1979 calls for the processing of the applications to be completed by 1984. Environmental, legal, and technical considerations could lead to the rejection of some of the PRLAs or result in acreage modifications or the addition of lease stipulations which restrict subsequent coal mining. These issues are discussed in more detail in chapter 9.

Lease or PRLA Acquisition Methods

Although each lease or prospecting permit was originally issued by DOI, there are several other methods by which the present owners have obtained leases or PRLAs.

The issuance of a lease or prospecting permit by the Federal Government is termed in this study de novo leasing or permitting. OTA found in a study of the 538 leases and 176 PRLAs outstanding as of September 30, 1979, that only 117 leases (22 percent of the lease total) and 19 PRLAs (11 percent of the total PRLAs) are still held by the original owner (see table 11). The remaining 78 percent of all leases and 89 percent of all PRLAs have been obtained by their present owners from previous owners through one of two methods: 1) assignment and 2) segregation.

Owners of leases or PRLAs may sell or transfer their contracts to other parties with approval of DOI. This process is called assignment. Assignments are essentially private transactions and any cash, property, service agreements, or overriding royalties are, with few limitations, between the buyer and seller.

Table 11.—Lease and PRLA Acquisition Method Used by Present Owner

Acquisition method	Number and percent of leases	Number and percent of PRLAs
De novo	117 (22%)	19 (11%)
Assignment	403 (75%)	133 (76%)
First	– 146	–76
Second	– 124	-27
Third or more	– 133	–30
Segregation	18[a] (3%)	24 (14%)

[a]The "Segregatlon" total in this table differs from the number (34) listed in table 9 because eight segregated leases were subsequently assigned to their present owners Also, table 9 includes 27 leases issued in late 1979 and in 1980 These leases were not Included in the above analysis

SOURCE: Office of Technology Assessment.

Approximately 75 percent of the outstanding leases and PRLAs were obtained by their current owner through assignment. Multiple assignments have been made on many leases and PRLAs; 124 leases have been assigned twice and 133 have changed hands three or more times. The 176 PRLAs have been assigned a total of **227** times.

Segregation, already discussed in this chapter (see table 9), has been used by the present owners of 18 leases and **24** PRLAs. Like assignments, segregations are largely transactions among private parties that are then recorded by the Federal Government.

Control of a coal lease or PRLA can be obtained without actually acquiring title through the de novo, assignment, or segregation procedures, This involves the purchase of a controlling interest in a firm which already owns leases or PRLAs. The acquired firm can then become a subsidiary of the purchaser and the purchaser is able to make decisions affecting the leases or PRLAs. Although transfers of title by assignment from the acquired company to the purchasing company often occur, they are not obligatory.

Corporate mergers and acquisitions have frequently involved leases and PRLAs. For example, at least 10 of the **36** leaseholding companies now operating as wholly owned subsidiaries once held leases as independent corporations. As another example, in 1980 three firms holding leases were purchased by major energy companies. Because lease title transfers do not always accompany corporate acquisitions, it is difficult to precisely determine the role of mergers in the leasing program; however it is clearly significant.

Ownership of Leases and PRLAs

Ownership of leases and PRLAs is shared by a number of unincorporated individuals and by a variety of diverse companies. Owners range from sole proprietors to joint ventures involving some of the largest corporations in the world. *

*Lease and PRLA ownership patterns and trends from 1950 to 1980 are discussed in greater detail in ch. 13. Lease owner-

About 115 corporations own coal leases or indirectly control them through subsidiaries or joint ventures. In addition, as of January 1, 1980, 59 individuals held leases in their own name. As of January 1, **1980, 29** companies and **18** individuals owned PRLAs.

Electric utilities hold 21 percent of all outstanding acreage under coal lease as of September **30, 1979,** more than any other single business category defined by OTA. Seventeen utilities now own leases. Eleven of the **18** largest oil companies (i.e., the oil majors) control 20 percent of leased acreage. Seven other business activity categories own leases covering at least 5 percent of all land under lease, ranging from 8 percent owned by Peabody Coal Co. (the largest single lessee) to 5 percent owned by nonresource-related diversified companies such as General Electric or Monsanto (see table 12 and ch. 13).

Table 12.—Major Business Activity Categories Holding Federal Coal Leases and PRLAs in 1980a

	Percent of leased land	Percent of land included in PRLAs
Electric utilities	21%	9%
Energy companies	20	16
Peabody Coal Co.	8	(In "other") (less than 5%)
Steel companies	8	0
Independent coal companies.	7	(In "other") (less than 5%)
Oil and gas (minor) companies	6	8
Unincorporated individuals	5	20
Natural gas pipeline companies	5	12
Nonresource-related diversified companies	5	(In "other") (less than 5%)
Kemmerer Coal Cob	4	10
Metals and mining companies.	2	9
Landholding companies	<1	1
"Other" companies.	10	14

[a]The office of Technology Assessment analyzed separately any business activity category (including Individual companies with unique business structures) holding at least 5 percent of all land under lease or PRLA at at least 1 of 7 analysis dates between 1950 and 1980. (See ch. 13). The analysis includes the 538 leases and 176 PRLAs in existence as of Sept. 30, 1979,

[b]In March 1981, Kemmerer Coal Co. was purchased by Gulf Oil Corp.

SOURCE: Office of Technology Assessment

Unincorporated individuals hold **20** percent of all land included in PRLAs, more than any of the eight business categories identified by OTA as major PRLA holders. The major energy companies rank second, with 16 percent. Other principal holders of PRLAs include natural gas pipeline, metals, oil or gas, and electric utility companies.

OTA found that lease and PRLA holders represent one of four types of business organizations. Most of the acreage under lease (43 percent) and under PRLA (44 percent) is held by subsidiaries of larger parent companies. Only 26 percent of all leased land and **12** percent of land under PRLAs is controlled by independent firms. Multicorporate entities, such as joint ventures, are the newest business organizations to control significant public coal land; they hold 25 percent of leased land and 22 percent of land under PRLAs. Finally, unincorporated individuals control 5 percent of land under lease and 20 percent of land under PRLAs.

Over the past 30 years, there has been a general decline in the percentage of leases and PRLAs held by small independent companies and unincorporated individuals. The proportion of leases held by large diversified firms and companies operating on leased land through subsidiary and multicorporate arrangements has risen. There has also been an increase in the number of different industries holding major shares in Federal leasing. The number of business categories holding at least 5 percent of all land under lease grew from four to nine between 1950 and 1980.

Continued from p. 51.

ship is discussed in considerable detail in the OTA Technical Memorandum Patterns and Trends in Federal Coal Lease Ownership: 1950-80, OTA-TM-M-7, March 1981.

Lease Development Status

A principal objective of this study is to examine mining activity on Federal leases and to assess the development potential of existing leases and PRLAs. During this analysis OTA divided the existing leases into units or blocks. A lease unit, as used by OTA, consists of either all leases included in the same active or proposed mine as defined by the mine plan, or one or more undeveloped leases that are owned by the same lessee and that are contiguous or sufficiently close together to form a compact minable unit. *

OTA divided the 565 existing coal leases into 256 units (see table 13). The smallest units contain one lease covering 40 acres. The largest, located in southern Utah, includes 21 leases and 40,277 acres. Colorado, Utah, and Wyoming together account for 176 lease units, 69 percent of the total.

OTA evaluated mining activity and mine development prospects for the 244 lease units located in the seven principal Western coal-producing States listed in table 13. The lease units were grouped in three categories according to stages of development. Each of the categories required a different type of data collection and analysis. The three development categories are:

- leases with approved mine plans;
- leases with mine plans submitted and pending approval; and
- leases without submitted mine plans.

Leases and lease units were placed in these categories based on OTA's review of all mine plans on file with the Office of Surface

'See ch. 2 for more information on the OTA methodology.

Table 13.—Number and Location of Leases and Lease Units

State	Number of leases	Number of lease units
Colorado	127	66
Montana	21	13
New Mexico	29	15
North Dakota	20	14
Oklahoma	46	26
Utah	204	56
Wyoming	101	54
Other States	17	12
Total	565	256

SOURCE Off Ice of Technology Assessment

Mining (OSM) on September 30, 1980. * The number of leases and lease units, acreage, and recoverable coal reserves in each of the three categories is shown in table 14 (see also fig. 9 in ch. 1). Information in this table is summarized below.

Leases With Approved Mine Plans

Approximately one-third of all leases and all lease units have approved mine plans. Many of the mines in this category are actively producing; however, some mines only recently received permit approval and have not yet begun commercial operations, The approved category also includes a small number of new leases issued in 1979 and 1980 to ensure the continued operation of existing mines (even if the approved mine plan has not yet been formally modified to add the new leases) and several leases included in pending amendments to approved mine plans.

In Montana, 54 percent of the lease units, containing 69 percent of the leased reserves are in approved mine plans (see table 15). New Mexico and Oklahoma have the smallest percentage of lease units in the approved category and Oklahoma and Utah the lowest percentage of leased reserves in the approved category.

Before a lessee can mine coal from a Federal lease, DOI must approve the proposed mining operation. Because only a por-

*Before coal can be produced from Federal land, a mine plan must be submitted to and approved by DOI. Hence, mine plan status provides a convenient yardstick by which to measure lease development. There are two separate requirements for mine plans for Federal leases. First, a mine plan must be submitted to comply with the general provisions and regulations under the Mineral Leasing Act of 1920 (MLA), as amended, and secondly, a mining and reclamation plan must be submitted for all surface and underground mines to comply with the Surface Mining Control and Reclamation Act of 1977 (SMCRA) whether or not Federal lands are involved. Under DOI directives, a single mining plan is submitted to OSM to meet both MLA and SMCRA requirements, however, OSM and the Geological Survey each retain their separate responsibilities for enforcement and permit approval.

Table 14.—Summary Table—The Development Status of Federal Coal Leases[a]

	Approved mining plans (including leases in production)				Pending mine plans				No mine plans			
	Number of leases	Number of units	Number of acres	Recoverable reserves billions of tons	Number of leases	Number of units	Number of acres	Recoverable reserves billions of tons	Number of leases	Number of units	Number of acres	Recoverable reserves billions of tons
Colorado	54 (43%)[b]	19 (29%)	42,086 (33%)	0.73 (32%)	21 (17)	11 (17%)	37,855 (30%)	0.46 (21%)	52 (41%)	36 (55%)	46,953 (37%)	1.06 (47%)
Montana	14 (67%)	7 (54%)	30,292 (81%)	0.83 (69%)	0	0	0	0	7 (33%)	6 (46%)	6,994 (19%)	0.37 (31%)
New Mexico	9 (31%)	2 (13%)	18,827 (42%)	0.17 (38%)	9 (31%)	3 (20%)	21,098 (47%)	0.18 (40%)	11 (38%)	10 (67%)	4,835 (11%)	0.10 (22%)
North Dakota	8 (40%)	4 (29%)	8,655 (46%)	0.12 (44%)	4 (20%)	3 (21%)	5,283 (28%)	0.10 (37%)	8 (40%)	7 (50%)	4,754 (25%)	0.05 (19%)
Oklahoma	7 (15%)	5 (19%)	8,668 (12%)	<0.01 <(5%)	1 (2%)	1 (4%)	680 (1%)	<0.01 <(5%)	38 (83%)	20 (77%)	64,698 (87%)	0.18 >(90%)
Utah	50 (25%)	14 (25%)	55,540 (20%)	0.79 (24%)	78 (38%)	11 (20%)	118,740 (42%)	1.27 (39%)	76 (37%)	31 (55%)	105,215 (38%)	1.19 (37%)
Wyoming	47 (47%)	23 (43%)	110,193 (51%)	4.7 (53%)	5 (5%)	3 (6%)	11,007 (5%)	0.53 (6%)	49 (49%)	28 (52%)	96,073 (44%)	3.6 (41%)
Other States	9 (53%)	7 (58%)	5,476 (40%)	0.02 (29%)	0	0	0	0	8 (47%)	5 (42%)	8,079 (60%)	0.05 (71%)
Total	198 (35%)[c]	81 (32%)	279,737 (34%)	7.4 (45%)	118 (21%)	32 (13%)	194,663 (24%)	2.5 (15%)	249 (44%)	143 (56%)	337,601 (42%)	6.6 (40%)

[a]See also table 6 in this chapter and fig. 9 in ch. 1.
[b]Percentages are percent of totals within the State, for each State.
[c]Percentages are percent of totals for all States

SOURCE: Office of Technology Assessment.

Table 15.—Leases in Production and With Approved Mine Plans

	Number of leases	Number of lease units	Acres	Recoverable reserves (billions of tons)
Colorado	54 (43%)[a]	19 (29%)	42,086 (33%)	0.73 (32%)
Montana	14 (67%)	7 (54%)	30,292 (81%)	0.83 (69%)
New Mexico	9 (31%)	2 (13%)	18,827 (42%)	0.17 (38%)
North Dakota	8 (40%)	4 (29%)	8,655 (46%)	0.12 (44%)
Oklahoma	7 (15%)	5 (19%)	8,668 (12%)	<0.01 (<5%)
Utah	50 (25%)	14 (25%)	55,540 (20%)	0.79 (24%)
Wyoming	47 (47%)	23 (43%)	110,193 (51%)	4.7 (53%)
Total	189 (34%)	74 (30%)	274,261 (34%)	7.4 (45%)

[a]Percentages are percent of total for each State except percent of total which is percent of seven State total.

SOURCE: Office of Technology Assessment.

tion of the approved permit area is mined in any given year, it is unlikely that all Federal coal leases in approved mine plans will be producing at one time. In 1980, coal was mined from about 100 Federal leases, which is about half of the leases in the approved category. Sixty-nine million tons of coal were mined from the producing leases in the seven Western State OTA study region (see table 16). Federal coal contributed 34 percent of all production from these States. In 1980, Federal coal provided 66 percent of Utah's entire output, 36 percent of Wyoming's production, but only 3.5 percent of the coal mined in North Dakota and only 5 percent of the coal mined in Oklahoma.

Leases With Pending Mine Plans

Approximately 21 percent of all leases and 15 percent of leased reserves are included in

Table 16.—1979 and 1980 Coal Production From Federal Leases and From Western States

	1979 production from Federal leases (millions of tons)	1979 total State coal production (millions of tons)	Percent of State coal output from leases, 1979	1980 production from Federal leases (millions of tons)	1980 total State coal production (millions of tons)	Percent of State coal output from leases, 1980
Colorado	7.7	18.1	43%	9.4	19.5	48%
Montana	8.6	32.5	26	10.4	36.1	29
New Mexico	5.4	15.1	36	6.3	16.5	38
North Dakota . . .	1.1	15.0	7	0.6	17.2	3
Oklahoma	0.3	4.8	6	0.3	4.9	5
Utah	6.9	11.8	58	8.7	13.1	66
Wyoming	30.1	71.8	42	33.4	94.0	36
Other States[a] . .	(0.14)	(178.8)	(less than 1%)	(small)	(—)	(less than 1%)
Total[b]	60.1	169.1	36%	69.1	201.4	34%

[a]Includes Federal production from Kentucky, Alabama, and Washington.
[b]Total does not include contribution from "other" States.

SOURCE: 1979 Federal production from U.S. Geological Survey accounting office. 1979 State production from the U.S. Energy Information Agency, *Week/y Coal Production Report,* Aug. 16, 1960.
1960 Federal production from U.S. Geological Survey, *Federal and Indian Lands Coal, Phosphate, Potash, Sodium and Other Mineral Production, Royalty Income, and Related Statistics,* June 1981. 1960 State production from the U.S. Energy Information Agency, Personal Communication to the Office of Technology Assessment, July 27, 1961.

the 13 percent of all lease units for which mine plans have been submitted to OSM and for which Federal approval is pending. This classification does not distinguish among lease units on the basis of quality of submitted mine plans, their date of submission, or the current stage of the review of the mine plan.

New Mexico, Utah, and North Dakota each have 20 percent of their lease units falling in the pending mine plan category. On the other hand, no pending mine plans affecting Montana leases are being studied by DOI and only 1 of Oklahoma's 26 lease units is included in a pending mine plan (see table 17).

Leases Without Mine Plans

Over half of all existing lease units, 44 percent of all leases, 42 percent of all leased

Table 17.—Leases With Pending Mine Plans

	Number of leases	Number of lease units	Acres	Recoverable reserves (billions of tons)
Colorado	21 (17%)[a]	11 (17%)	37,855 (30%)	0.46 (21%)
Montana.	0 —	0 —	0 —	0 —
New Mexico	9 (31%)	3 (20%)	21,098 (47%)	0.18 (40%)
North Dakota . . .	4 (20%)	3 (21%)	5,283 (28%)	0.10 (37%)
Oklahoma	1 (2%)	1 (4%)	680 (1%)	<0.01 (<5%)
Utah	78 (38%)	11 (20%)	118,740 (42%)	1.27 (39%)
Wyoming	5 (5%)	3 (6%)	11,007 (5%)	0.53 (6%)
Total	118 (21%)	32 (13%)	194,663 (24%)	2.5 (15%)

[a]Percentags are percent of total for each State except percent of total which is percent of seven State total.

SOURCE: Office of Technology Assessment

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acreage, and 40 percent of leased reserves have not been developed to the point of a mine plan submission to OSM.

Preliminary development activity varies widely on these undeveloped units, from extensive exploration drilling and mine plan preparation on some units to no activity at all on others (see ch. 6).

Oklahoma has the largest proportion of Federal coal leases without mine plans, and five of the seven Western States have over 30 percent of their leased Federal reserves in this category (see table 18). Sixty-seven percent of New Mexico's lease units have no mine plans, but they cover just 22 percent of leased reserves.

Table 18.—Leases for Which No Mine Plans Have Been Submitted

	Number of leases	Number of lease units	Acres	Recoverable reserves (billions of tons)
Colorado	52 (41%)[a]	36 (55%)	46,953 (37%)	1.06 (47%)
Montana	7 (33%)	6 (46%)	6,994 (19%)	0.37 (31%)
New Mexico	11 (38%)	10 (67%)	4,835 (11%)	0.10 (22%)
North Dakota	8 (40%)	7 (50%)	4,754 (25%)	0.05 (19%)
Oklahoma	38 (83%)	20 (77%)	64,698 (87%)	0.18 (>90%)
Utah	76 (37%)	31 (55%)	105,215 (38%)	1.19 (37%)
Wyoming	49 (49%)	28 (52%)	96,073 (44%)	3.6 (41%)
Total	241 (44%)	138 (57%)	329,522 (41 %)	6.6 (40%)

[a]Percentages are percent of total for each State except percent of total which is percent of seven State total.

SOURCE: Office of Technology Assessment.

CHAPTER 4

Federal Coal Resources

Contents

List of Tables

List of Figures

CHAPTER 4
Federal Coal Resources

Coal quality, geologic conditions, mining methods, and end uses of Federal coal are important factors that affect the development of individual Federal coal leases, and also the general development of coal resources in the Western United States. The following topics are discussed in this chapter:

- geographic location of Federal surface and underground coal reserves under lease and preference right lease applications (PRLAs) in the major Western coal regions;
- trends in Federal surface and underground coal production in the different regions;
- uses and market areas of coal from the major Federal coal States;
- quality of coal in the Western coal regions, and characteristics of major leased coal reserves and coalfields; and
- geologic conditions and mining methods in the major coal regions that are important in the development of Federal coal reserves.

Location of Leased Federal Coal Reserves

Leased Federal coal reserves are located in 14 States and in 5 of the 6 major coal regions of the United States (fig. 16). However, most Federal coal is located in two coal regions in the Northern Great Plains coal province and seven coal regions in the Rocky Mountain coal province (see fig. 17). * Federal leases in these two provinces include over 98 percent of the approximately 16.5 billion tons of recoverable coal presently under lease.

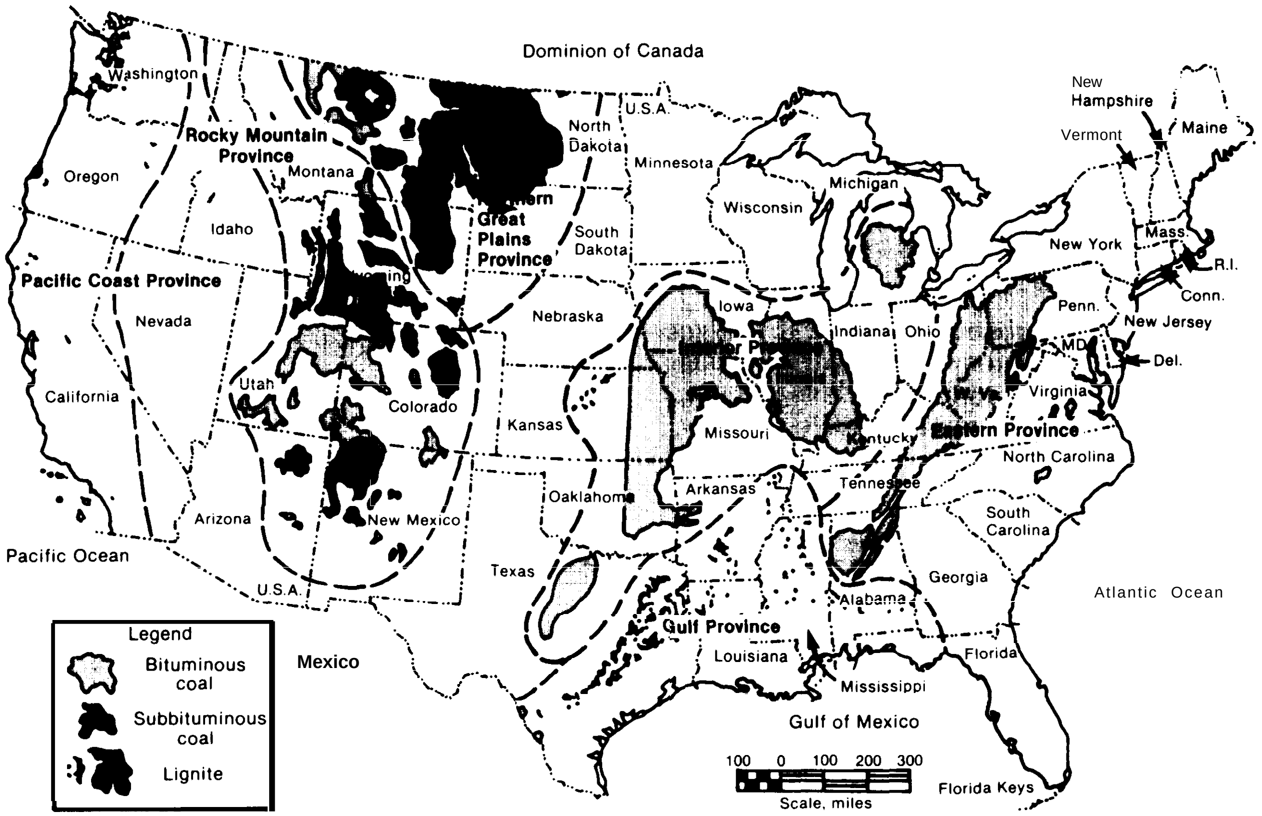
Three-quarters of the leased Federal coal reserves outside of the Northern Great Plains and Rocky Mountain coal provinces are contained in 46 leases in Oklahoma, which is geologically part of the Interior coal province. The remaining reserves (0.4 percent of the total under lease) are found in 17 leases in the States of Alaska, Alabama, California, Kentucky, Oregon, Pennsylvania, and Washington. Leases in these seven States were not analyzed by OTA. Leases in Oklahoma were evaluated by OTA and some data on this State is included in this chapter, but Oklahoma is discussed in less detail than the major Federal coal States of Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming.

The United States has several hundred billion tons of recoverable coal reserves, which are approximately evenly distributed between the Eastern and Western halves of the country.* These reserves are very large com-

*A number of different terms are used to describe areas in which coal deposits are located. Coal provinces cover a large geographic area where coal deposits have a relatively similar geologic and physiographic setting. The continental United States has six major coal provinces (see fig. 16). Coal provinces are usually divided into geologically distinct coal regions (or basins, where the geologic structure of the region is in the form of a basin) which also cover relatively large areas (generally hundreds of thousands to millions of acres) of coal-bearing rocks. Coal regions may be further divided into coal fields which generally cover areas of thousands or tens of thousands of acres, and identify specific deposits of minable coal, or a number of coal deposits with a similar geologic setting. Fig. 17 also shows the location and names of the major coal regions and fields in which Federal coal is leased.

*Various terms are used to describe quantity of coal. In-place resources (also called the resource or reserve base) include all coal deposits, regardless of depth, thickness, or economic recoverability. Minable resources represent the portion of the in-place resource that can be mined under present technology and economic conditions. Recoverable reserves refer to the amount of coal that can actually be recovered; this is always less than minable resources because some coal is lost during mining, and in some cases, some coal may be unavailable because of environmental and regulatory factors. Use of the term reserves in this chapter is synonymous with recoverable reserves. The demonstrated reserve base in the United States is estimated to be 475 billion tons (Demonstrated Reserve Base of Coal in the U.S. on Jan. 1, 1979, EIA, May 1981]. An earlier OTA report has estimated recoverable reserves in the United States to total 283 billion tons (The Direct Use of *Coal* p. 63, OTA-E-86, April 1979). Experts differ in specific estimates of total recoverable reserves in the United States, but generally agree that it is on the order of several hundreds of billion tons or more.

Figure 16.—Generalized Coal Provinces of the United States



SOURCE U S. Bureau of Mines, adapted from USGS Coal Map of the United States, 1960

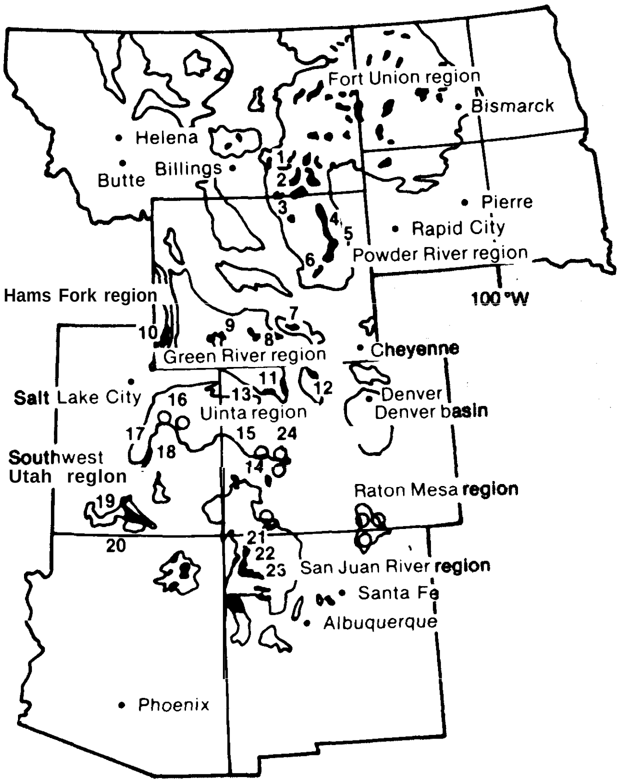
pared with the 820 million tons of coal produced in the United States in 1980. Slightly more than half of the recoverable reserves in terms of tonnage and slightly less than half in terms of heat content are found in the West. *

Federal coal leases are located primarily in six coal production regions in the West: Fort Union, Powder River, Green River-Hams Fork, Uinta-Southwest Utah, Denver-Raton Mesa, and San Juan River (see fig. 18). These coal production regions have been delineated along administrative boundaries of the Bureau of Land Management (BLM) for the purpose of implementing the new Federal coal management program and do not exactly coincide with geologic coal region boundaries. For example, the Danforth Hills coal field, which is geologically part of the Uinta coal region, is located within the Green River-Hams Fork production region. Also, some areas of the Uinta-Southwest Utah coal production region are geologically part of the San Juan River coal region. Unless coal production regions are specifically referred to (as in table 19), discussion in this chapter refers to geologic coal regions. *

*Coals in the West have generally a lower heat content than coals in the East (i.e., more coal must be burned to provide the same amount of energy). About 60 billion tons of underground subbituminous coal in the Powder River Basin of Wyoming and Montana cannot be economically mined now. (F. X. Murray (cd.), Where We *Agree:* Report of the National Coal Policy Project V.2 (Boulder, Colo.: Westview Press, 1978).) If this coal is subtracted from the reserve totals, the West's share of recoverable reserves according to heat content drops to approximately 40 percent of total U.S. reserves (National Research Council, Surface Mining: Soil, Coed and Society, Washington, D. C.: National Academy Press, 1981).

*There are a few Federal leases that are located in coal regions that are not included in the Federal coal production regions. These include two small leases in the Bighorn basin in

Figure 17.—Sketch Map Showing Major Coal Regions With Leased Federal Coal, and Generalized Location of Strippable and Metallurgical Coal Deposits



~ Area of coal reserves - Generalized location of strippable reserves O Major areas of metallurgical coal

Numbers show locations of major coal fields with leased Federal coal:

1. Colstrip	13. Danforth Hils
2. Decker	14. Somerset
3. Buffalo	15. Book Cliffs (CO)
4. Powder River	16. Book Cliffs (UT)
5. Gillette	17. Wasatch Plateau
6. Glenrook	18. Emery
7. Hanna	19. Alton
8. Little Snake River	20. Kapalrowits Plateau
9. Rook Springs	21. Fruitland
10. Kemmerer	22. Bisti
11. Yampa	23. Star Lake
12. North Park	24. Carbondale Coal Basin

SOURCE Base Map National Academy of Sciences, *Rehabilitation Potential of* **Western** *Coal Lands* (Cambridge, Mass Ballinger Press, 1974)

Continued from p. 60.

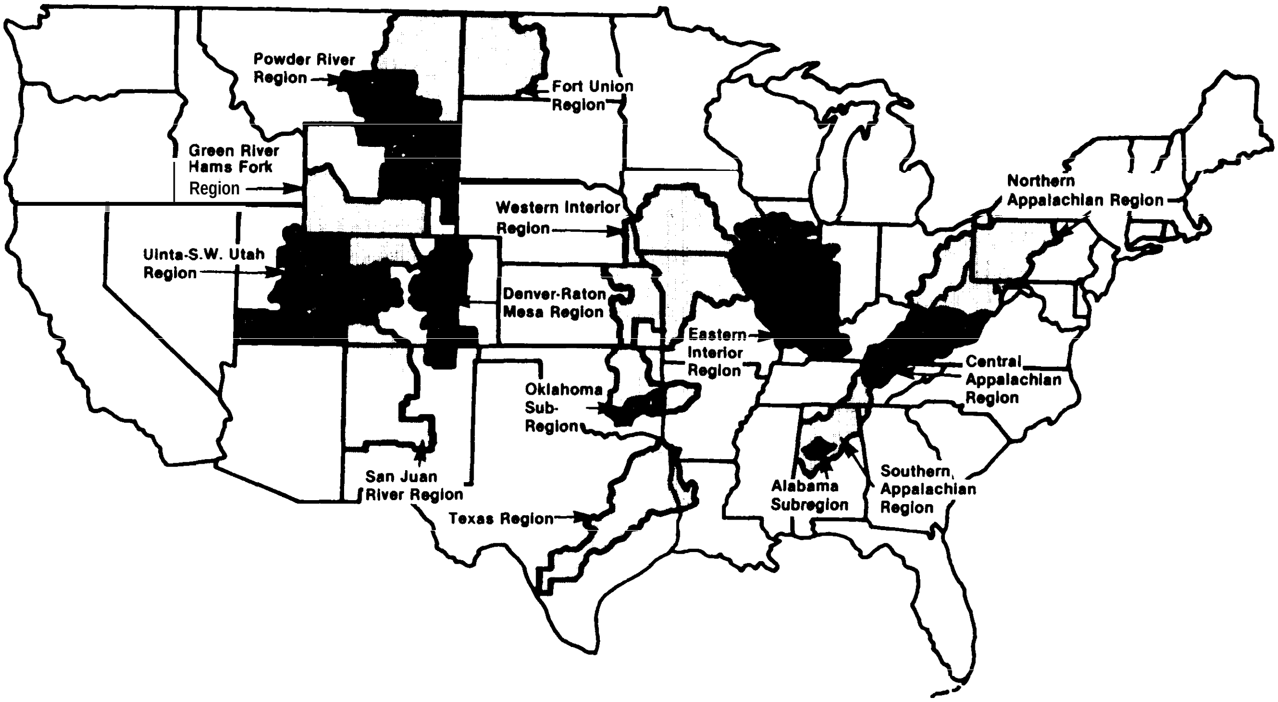
north-central Wyoming and one small lease in the Yellowstone region in southwestern Montana. Very small reserves are involved with these leases so these regions are not discussed in this chapter.

Coal reserves under Federal lease and PRLAs are unevenly distributed among the seven major Federal coal States (see table 20). Wyoming alone contains more than half (56 percent) of the reserves under lease, and Utah, the State with the next largest leased reserves has 20 percent of the total. Wyoming and Utah together contain more than three-quarters of the reserves under Federal lease. Wyoming also has the largest percentage of reserves under PRLA (43 percent), followed by New Mexico (26 percent) and Colorado (18 percent). These three States account for nearly 90 percent of the reserves under PRLA. Most Federal leased reserves are surface minable (1 1.3 billion tons, or 69 percent) as are most of the reserves under PRLA (3.6 billion tons, or 63 percent). The majority of leased reserves in Montana, New Mexico, North Dakota, and Wyoming are surface minable; most of the leased reserves in Colorado, Utah, and Oklahoma will have to be mined by underground methods.

Table 19 shows the distribution of Federal coal reserves under lease and PRLA by coal production region. The Powder River region in Montana and Wyoming, contains 59 percent of the leased reserves and the Uinta-Southwest Utah production region in Utah and Colorado contains 25 percent of the leased Federal reserves. The two regions combined contain 84 percent of the coal under lease.

The large amount of leased Federal coal reserves in the Powder River basin reflects the region's large reserves in thick flat-lying coal seams that can be easily surface mined and the high percentage of Federal coal ownership in the area. The thick seams in the Powder River basin can be mined at a substantially lower cost than other U.S. coal deposits. Federal coal leases are concentrated in the Uinta-Southwest Utah region because of its diversity of high-quality coals including metallurgical coal. The region is one of the oldest active mining areas in the West. The majority of reserves under lease in the Uinta-Southwest Utah region must be mined underground. The Green River-Hams Fork

Figure 18.–Coal Production Regions in the United States: Nov. 9,1979



Note: The boldface print indicates regions or subregions that have been officially designated as Federal Coal Production Regions.

SOURCE: U.S. Department of the Interior, *Federal Coal Management Report, Fiseal Year* 1979 (Washington, D.C.: U.S. Government Printing Office, 1980).

region of northwestern Colorado and southwestern Wyoming has a fairly even division between surface and underground minable reserves.

Of the total Federal reserves covered by PRLAs, 45 percent are located in the Powder River basin. The 2.4 billion tons of PRLA reserves in the Powder River basin include some 760 million tons that are recoverable only by underground or in situ methods. Consequently these underground reserves are unlikely to be developed commercially within the next 10 years. [1] If these underground PRLA reserves are excluded from the total reserves under PRLA, the Powder River basin still contains 35 percent of the total. The San Juan River region with 28 percent (32 percent if Powder River underground reserves are subtracted) and Denver-Raton Mesa region with 14 percent (or 16 percent) also have substantial amounts of reserves under PRLA.

[1] J. R. Boulding and D. Pederson Development and Production Potential of Undeveloped Federal Coal Leases and Preference Right Lease Applications in the Powder River Basin and Other Wyoming Coal Basins, final report (Washington, D. C.: Office of Technology Assessment, 1981). PRLAs must have commercial quantities of coal to qualify for a lease. It is possible that in situ gasification may allow development of underground coal in the Powder River basin, but this technology is still experimental in nature, and is likely to be so until after 1984, which is the deadline for processing all PRLAs, Consequently, it is possible that areas under PRLA that include only underground reserves may not have leases granted.

Table 19.—Distribution of Recoverable Coal Reserves Under Federal Lease and Preference Right Lease Application by Major Coal Production Region

Coal production region	State	Number of leases[a]	Recoverable reserves (billions of tons)[b]: Under lease: Surface	Under lease: Underground	Under lease: Total	Preference right lease applications: Surface	Preference right lease applications: Underground	Preference right lease applications: Total	FY79 Federal coal production (millions of tons)[f]: Surface	FY79 Federal coal production: Underground
Fort Union	ND	17	0.25	0		0	0	0		
	MT	3	0.28	0		e	o	– e	0.7	0
		20	0.53	0	0.53				(100%)	
			(100%)*		(3%)**					
Powder River	MT	15	0.83	0						
	WY	54	8.3	0.32		1.6	0.76	2.4	31.8	0
		69	9.1	0.32	9.5	(68%)*	(32%)*	(45%)**	(100%)*	
			(97%)	(3%)*	(59%)					
Green River-Hams Fork	WY	32	0.43	0.17						
	CO	56	0.46	0.57		0.08	0.22	0.30	11.6	0.7
		88	0.89	0.74	1.6	(28%)	(72%)	(6%)	(94%)	(6%)
			(55%)	(45%)	(10%)					
Uinta-Southwest Utah	UT	201	0.27	3.0						
	CO	61	0.01	0.78		0.09	0.38	0.48	0	9.0
		262	0.28	3.8	4.1	(20%)	(80%)	(9%)		(100%)
			(7%)	(93%)	(25%)					
Denver-Raton Mesa	CO	5	0.05	0.02						
	NM	4	– c	– c		0.68	0.06	0.74	0	0
		9	0.05	0.02	0.07	(91%)	(9%)	(14%)		
			(71%)	(29%)	(<1%)					
San Juan River	NM	25	0.27	0.06						
	CO	1	– d	– d		0.83	0.67	1.5	4.7	0.1
		26	0.27	0.06	0.33	(55%)	(45%)	(28%)	(98%)	(2%)
			(82%)	(18%)	(2%)					
Total		474	11.2	4.9	16.1	3.3	2.1	5.4	48.8	9.8
			(70%)	(30%)		(61%)	(39%)	(100%)	(83%)	(17%)

*Numbers in parentheses represent percent of total reserves or production in the region.
**Numbers in parentheses represent percent of total reserves in all regions combined.
[a]AS OF SEPT 30, 1979, TOTALS DIFFER FROM TABLE 20 BECAUSE A FEW LEASES IN MONTANA AND WYOMING ARE LOCATED OUTSIDE OF THE PRODUCTION REGION BOUNDARIES AND BECAUSE A NUMBER OF LEASES WERE LET BETWEEN MID-1979 AND SEPTEMBER 1980.
[b]SOURCE. Automated Coal Lease Data System, Sept, 30, 1979, pages A-8 and A-14, U.S. Department of the Interior, Federal Coal Managemenf Report, Fiscal Year 1979 (Washington, D.C.: U.S. Government Printing Office, 1980). TOTALS FOR REGIONS ARE SLIGHTLY LESS THAN STATE TOTALS IN TABLE 20 BECAUSE A FEW LEASES IN MONTANA AND WYOMING ARE LOCATED OUTSIDE OF THE PRODUCTION REGION BOUNDARIES.
[c]Small reserves in New Mexico included in Colorado total to protect confidentiality of information.
[d]Small reserves in Colorado Included in New Mexico total to protect confidentiality of information.
[e]Small reserves in Montana not listed to protect confidentiality of information
[f]For fiscal year 1979, from page A-11 in USDI report cited in footnote b. Total is slightly less than in table 16 in ch. 3 because data is for fiscal year rather than calendar year.

Federal Coal Production

In 1979, 60,1 million tons of Federal coal were mined (and in 1980, 69 million tons), of which nearly 99.5 percent was produced in the six major Federal coal States of Colorado, Montana, North Dakota, New Mexico, Utah, and Wyoming. Figure 19 shows the trends in Federal coal production and total coal production from 1957 to 1979 in these six States.

Table 20.—Distribution of Recoverable Coal Reserves Under Federal Lease and Preference Right Lease Application by State

State	Number of leases[a]	Number of PRLA's[e]	Recoverable reserves under lease[b] (billions of tons)			Recoverable reserves under preference right lease application[b] (billions of tons)		
			Surface	Underground	Total	Surface	Underground	Total
Colorado	127	37	0.55 (28%)*	1.4 (71%)*	2.0 (12%)**	0.74 (71%)*	0.30 (29%)*	1.0 (18%)**
Montana	21	4	1.1 (100%)	0	1.1 (7%)	—[c]	—[c]	—[c]
New Mexico	29	28	0.27 (82%)	0.06 (18%)	0.33 (2%)	0.83 (55%)	0.67 (45%)	1.5 (26%)
North Dakota	20	0	0.25 (100%)	0	0.25 (2%)	0	0	0
Oklahoma.	46	4	0.01 (6%)	0.19 (94%)	0.2 (1%)	c	—[c]	—[c]
Utah.	204	25	0.27 (8%)	3.0 (92%)	3.3 (20%)	0.09 (26%)	0,27 (74%)	0.36 (6%)
Wyoming.	101	74	8.8 (95%)	0.49 (5%)	9.3 (56%)	1.6 (66%)	0.8 (34%)	2.5 (43%)
Total	548	172	11.3 (69%)	5.1 (31%)	16.5 (100%)	3.6[d] (63%)	2.1[d] (36%)	5.7[d,e] (100%)

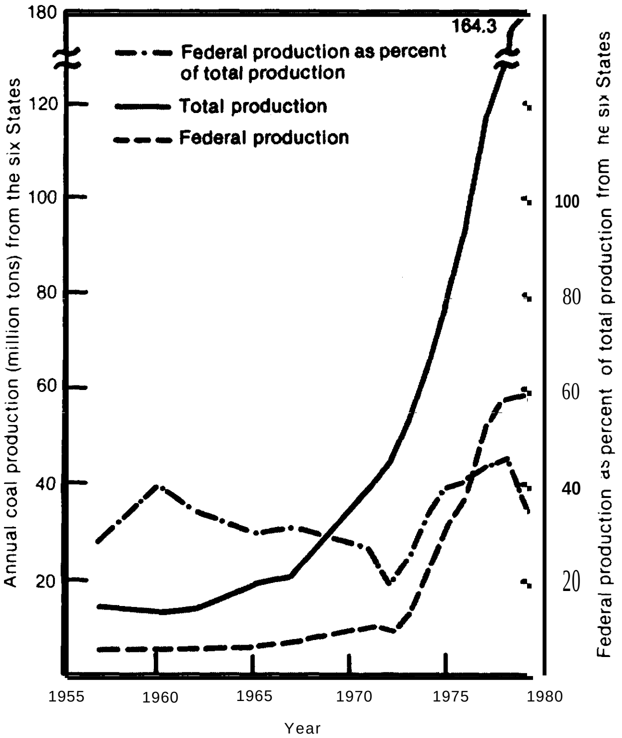
● Numbers in parentheses represent percent of total leased reserves in the State.
●● Numbers in parentheses represent percent of total reserves in all States.
[a]Includes all leases outstanding as of September 30, 1980, Seventeen leases with small reserves in Alaska, Alabama, California, Kentucky, Oregon, Pennsylvania, and Washington are not included in this table.
[b]SOURCE: Automated Coal Lease Data System, Sept. 30, 1979, pages A-7 and A-12, U.S. Department of the Interior, Federal Coal Management Report, Fiscal Year 1979 (Washington D.C.: U.S. Government Printing Office, 1960). NOTE THAT TOTALS HERE DIFFER SLIGHTLY FROM RESERVE FIGURES DISCUSSED IN CH. 3 AND CH. 6. FOR THE PURPOSE OF DISCUSSION IN THIS CHAPTER. THESE DIFFERENCES ARE NOT SIGNIFICANT.
[c]Reserves not shown due to confidentiality requirements.
[d]Includes 315.2 million tons of surface and 15.8 million tong of underground reserves in eight PRLAs in Montana and Oklahoma.
[e]There are also four PRLAs in Alaska with 0.1 billion tons of recoverable reserves. See table 10. Extent *and Location of PRLAs* in ch. 3.

Between 1957 and 1967 total production from these States ranged between 3.2 and 3.8 percent of total U.S. production, but production increased dramatically during the 1970's to 21 percent in 1979 and 24 percent in 1980. Federal coal production from these States during this same period ranged between 0.9 and 1.3 percent of total U.S. production and increased to about 8 percent in 1979 and 1980.

Figure 19 also shows the changes in percentage contribution of Federal coal to total coal production for these six States. Between 1960 and and 1972 the share of Federal coal production in the six States declined from about 40 percent to 20 percent. Since 1973 the percentage of Federal coal production has shown a general increase, although in 1979, even though total Federal production was more than eight times higher than in 1970, its percentage share of all production (36 percent) was less than in 1960. During the next decade, Federal coal production will probably increase at a higher rate than non-Federal coal production because of the large increases from the Powder River region, where most coal reserves are owned by the Federal Government.

The current trend in production of Western Federal coal is toward large surface or underground mines producing more than 1 million tons per year. In Utah and Colorado where underground mines are common, small- and medium-sized mines ranging from 200,000 to 1 million tons per year in capacity still represent a significant and vital share of active and planned mines. Several mines on Federal leases in the Powder River basin have planned capacities exceeding 20 million tons per year. Annual production from one of these mines will exceed the individual 1979 total production from Colorado, New Mexico,

Figure 19.—Annual Coal Production From the Six Major Federal Coal-Producing States in the West, 1957-79a



aThe six States are Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming

SOURCE Data for 1957.77 from table 2-7, U.S. Department of Interior, *Final Environmental States Federal Coal Management Program* (Washington, D C U S Government Printing Office, 1979) 1978 data from table A-2, U S Department of In tenor *Federal Coal Management Report* Fiscal Year *1979* (Washington, D C U S. Government Printing Off Ice, 1980) 1979 data from table 16 ch. 3 of this report

North Dakota, or Utah (18.1 million, 15.1 million, 15.0 million and 11.8 million tons, respectively).

The trend toward large mines contrasts sharply with coal production from the period 1920 to 1960. Most of the leases issued during this period were to individuals or small mining companies that produced relatively small amounts of coal for domestic or local industrial consumption. For example, about half (65 out of 138) of the leases issued before 1960 produced coal at one time, but are no longer producing coal. Most of the production from these leases was from small underground mines, and sum total cumulative production from 59 of these leases was less than a million tons.[2] This is less than the annual production of typical new mines on Federal leases.

The last two columns in table 19 show the breakdown between Federal surface and underground coal producton from the different coal regions. Surface mines accounted for 48.8 million tons, or 83 percent of Federal production in 1979. Since only 70 percent of reserves under lease, and 61 percent of reserves under PRLA* are surface minable, present production is concentrated more heavily on leases with surface reserves than underground reserves. Many leases with large surface reserves in the Powder River basin were not producing coal in 1979, so the emphasis on development of surface reserves will probably continue over the next 10 years or so. However, full development of existing reserves will have to rely increasingly on more costly underground mining methods.

[2]Data from Automated Coal Lease Data System, Summary of Federal Leases—Oct. 1, 1979 prepared by the Bureau of Land Management for OTA, including cumulative production from each lease, and production in fiscal year 1979. Of the other leases issued between 1920 and 1960, 38 (27 percent of total) produced coal in 1979, and 35 (25 percent of total) never produced coal.

*Table 19 shows that only 61 percent of the reserves under PRLA are surface minable, but if the subbituminous underground reserves in the Powder River basin are subtracted. as discussed earlier, the percentage changes to 71 percent.

Coal Ownership Patterns

Production from Federal coal leases must also be understood in the context of the coal ownership patterns that exist in the West. From the time of the early settlement of the West until the late 19th century, Federal coal passed into non-Federal ownership under a variety of laws and procedures. Under the homestead laws passed in the early 1900's, the Federal Government retained ownership of the coal and other mineral rights in lands patented to settlers. Passage of the Mineral Leasing Act of 1920 ended the era of disposal of Federal coal lands and established a leasing system for coal and other fuel and fertilizer minerals on Federal lands. The pattern of coal ownership in the West has been generally stable since then. * The major categories of non-Federal coal ownership are: Indian, railroad, State, and private (often called fee coal because the owner holds fee simple title to the coal).

Sixty percent is a figure that is commonly cited as the amount of coal resources controlled by the Federal Government in the West. This figure originates from estimates made by State BLM offices of Federal coal ownership in coal-bearing lands (i.e., geologic formations known to contain coal deposits) in the major Federal coal States (see table 21) and probably does not accurately reflect the percentage of Federal ownership of recoverable coal reserves. This is because: 1) coal deposits are not evenly distributed throughout areas of coal-bearing rocks, and 2) the percentage of Federal coal landownership varies between coal regions.

A closer approximation (but still not entirely accurate, as discussed later) of Federal ownership of coal resources can be obtained by looking at the percentage of Federal coal land ownership in known recoverable coal resource areas (KRCRAs). A KRCRA is an administrative and technical classification established by the U.S. Geological Survey to designate areas where the location and amount of minable coal deposits have been reasonably well-defined by geologic mapping and coal exploration. KRCRAs must be formally designated by publication in the Federal Register. Minable coal reserves are found outside KRCRAs, but generally there is less information available about the extent of the reserves and little or no commercial coal mining in these areas. Table 21 shows that the six major Federal coal States contain 116.7 million acres of coal-bearing lands, but that only 17.5 million acres (15 percent) had been included in KRCRAs as of March 1978.

Table 21 also shows that the percentage of Federal coal acreage varies considerably between States and coal regions. The percentage of Federal coal ownership in KRCRAs range from a low of 32 percent in North Dakota to a high of 90 percent in the Colorado portion of the Uinta region. Other KRCRAs with a high percentage of Federal coal ownership are the Wyoming portion of the Powder River basin (82 percent), the New Mexico portion of the San Juan region (82 percent) and Utah (85 percent).

Overall, the percentage of Federal coal ownership in KRCRAs in the six major Federal coal States is higher than the percentage of Federal ownership in coal-bearing areas (65 percent v. 52 percent). Furthermore, the DOI estimates that the Federal Government owns about 72 percent of the recoverable coal reserves in KRCRAs because of the high percentage of Federal coal ownership in the Powder River basin where coal seams are exceptionally thick. [3] However, Federal ownership of total recoverable coal reserves in the West is probably lower than this percentage for several reasons: 1) a number of Indian tribes control substantial amounts of coal reserves that are not included in KRCRAs* and 2) identification of KRCRAs has tended to focus on areas of high Federal coal ownership and active coal exploration or leasing interest. Identification of new KRCRAs may tend to be located in areas where the percentage of Federal coal ownership is lower (such as the Raton Mesa region). When all

*Further changes in coal ownership patterns are possible through exchanges of Federal and non-Federal coal, but the amounts of coal involved are relatively small compared to total leased reserves and the overall relationships among categories of coal ownership are likely to remain much the same. Exchanges are discussed in more detail in ch. 9.

[3] U.S. Department of Interior, Final Environmental Statement Federal Coal Management Program (Washington, D. C.: U.S. Government Printing Office, 1979), p. 2-5.

*Twenty Indian reservations in the West contain coal-bearing rocks and Indians control an estimated 15 percent of the strippable coal reserves in the United States (Council of Energy Resource Tribes, The Control and Reclamation of Surface Mining on Indian Lands, Washington, D.C.: CERT, Sept. 30, 1979). Indian reservations with significant amounts of minable coal reserves are: Craw and Northern Cheyenne in southeastern Montana, Fort Berthold in North Dakota, and the Hopi and Navajo in Arizona and New Mexico.

Table 21.—Federal Coal Ownership in Coal Regions and Known Recoverable Coal Resource Areas in the Six Major Federal Coal States

State/coal production region	Federal coal acreage[a] (million acres)	Total coal acreage (million acres)	Known recoverable coal resource areas[d]: Federal coal (million acres)	Known recoverable coal resource areas[d]: Total coal (million acres)
North Dakota	5.6(25)[b]	22.4	0.8(32)[e]	2.5(11)[f]
Montana/Fort Union			0.5(44)	1.2
Powder River			1 .7(75)	2.3
Total	24.6(75)	32.8	2.2(64)	3.5(1 1)
Wyoming/Powder River			3.3(82)	4.0
Green River-Hams Fork			1.2(55)	2.2
Total	11 .8(39)	30.5	4.5(73)	6.2(19)
Colorado/Green River-Hams Fork			0.3(68)	0.5
Uinta			0.5(90)	0.6
San Juan			0.2(59)	0.3
Denver-Raton Mesa[g]			0.1(20)	0.5
Total	8.7(53)	16.6	1.1(58)	1 .9(11)
Utah/Uinta-Southwest Utah	4.1(82)	5.0	0.9(85)	1 .1(22)
New Mexico/San Juan			1.8(82)	2,3
Raton Mesa[g]			o	0
Total	5.5(59)	9.4	1.8(82)	2,3(24)
Total (6 States)	**60.3(52)**	**116.7**	**11.3(65)**	**17.5(15)**
Total all States	**92.1 (61)[c]**	**150.2**	—	—

[a]From table 1-31 US. Department of the Interior, *Final Environmental Impact Statement, Proposed Federal coal Leasing program* (Washington, DC.: U.S. Government Printing Office, 1975). Figures are based on BLM State Office estimates.
[b]Numbers in parentheses indicate percent of total coal acreage in the State.
[c]This total includes 23.4 million acres (97 percent of total Coal acreage) of Federal coal in Alaska and 0.4 million acres (4 percent of total coal acreage of Federal coal in Oklahoma).
[d]Known Recoverable coal Resource Areas defined as of March 1978, A few of these KRCRAs include small amounts Of Indian coal, but Indian coal within reservation boundaries (which include the majority of Indian coal reserves) IS not included in KRCRAs.
[e]From table 2-5, U.S. Department of the Interior, Final Environmental Statement Federal Coal Management Program (Washington, D. C.: U.S. Government Printing Office, 1979), Totals may not add because of rounding. Numbers in parentheses Indicate percent of total KRCRA acreage in the State or region. Percentages may not match numbers in table because of rounding.
[f]Numbers in parentheses indicate percentage of total coal acreage in the State or region (the second column in table).
[g]Raton Mesa region did not include any areas designated as a KRCRA as of March 1978,

SOURCE: Office of Technology Assessment.

these factors are taken into consideration, Federal ownership of total recoverable reserves in the six major Federal coal States is probably somewhere between 50 percent and 60 percent.

Overall, the landownership patterns in the West are probably no more complex than those found in the East and Midwest, however, because Federal, State, and Indian lands generally cannot be sold, a coal operator cannot gain ownership or control of a potential mine area through purchase of the title to surface and mineral rights as he might in other regions. Consequently, a single mining unit in Western States will often include coal reserves of several different ownership categories to allow maximum recovery of the reserves and Federal and non-Federal coal reserves are frequently mined as part of the same operation. * For example in Campbell County, Wyoming, which has a high percentage of Federal coal, 16 out of 20 lease units involving Federal leases have non-Federal coal associated with them, Federal coal is in-

*Mining of coal held by a single owner is often possible and has been done in areas of mixed ownership, but in some cases recovery rates are reduced because mining operations cannot be designed for maximum efficiency.

terspersed with alternate sections (a section is a square mile and covers 640 acres) of railroad coal over hundreds of thousands of acres in the Fort Union region, the Montana portion of the Powder River region and the Wyoming portion of the Green River-Hams Fork region. This situation also exists in limited areas of the San Juan Basin in New Mexico. Mining in these areas usually involves both Federal and non-Federal coal. In parts of North Dakota, on the other hand, current development of lignite reserves is concentrated in areas where relatively small amounts of Federal coal are interspersed with State and private coal. The Crow and Northern Cheyenne tribes in southeastern Montana own large blocks of surface minable coal (estimated to exceed 5 billion tons) most of which can be mined without involving Federal, State, or private coal. About one-third of the 168 million tons of potential production capacity from the Montana Powder River basin involves only Indian coal.[4] All the major coal deposits in Arizona are located on the Navaho and Hopi Reservations, and all coal production in the State comes from those lands. The Navaho tribe also has important coal reserves in New Mexico. Current production of coal in New Mexico comes from Indian, Federal, State, and private land. Only one currently operating mine involves mixed ownership of Indian, Federal, and private coal.

[4]See table 65 of this report. See also tables 6.8, vol. 1 and A.4.3, vol. 2 of J. R. Boulding and D. Pederson, Development and Production Potential of Undeveloped Federal Coal Leases and Preference Right Lease Applications in the Powder River Basin and Other Wyoming Coal Basins, Final Report (Washington, D. C.: Office of Technology Assessment, 1981). Note that the 168 million tons per year production capacity cited here is higher than planned capacity for 1990; the 168 million tons figure is potential capacity in the post-1990 period. It does not depend on new leasing of Federal coal, but does depend on a number of factors including, for example, the building of the proposed Tongue River Railroad.

Coal Use and Market Areas

Table 22 summarizes current uses and market areas for coal produced in States with significant amounts of leased Federal coal. Possible new markets for Federal coal are discussed in chapter 5. By far the largest end use of coal for all States is steam electric generation. In Wyoming, North Dakota, and New Mexico, over 90 percent of all the coal mined is used by electric utilities. There is considerable flexibility in the quality of coal that can be used for new powerplants because a boiler can be designed to accommodate almost any coal. Existing powerplants have less flexibility because use of coal with heat content and sulfur and ash content significantly different from coal for which the boiler was designed often reduces its efficiency.

In contrast to the electric utility industry, the steel industry has much stricter specifications for its coal. Coke, which is made from metallurgical-grade coal, is used in the production of steel from iron ore. Metallurgical-grade coal generally requires a low sulfur and ash content and medium to low content of volatile matter, as well as other specific physical characteristics. Although low-sulfur and low-ash coal is found throughout the West, relatively few coal deposits have the other characteristics necessary for the production of coke. Colorado, Utah, New Mexico, and Oklahoma are the only Western States with significant commercial deposits of metallurgical-grade coal. Major deposits of high-grade metallurgical coals are found in portions of the Uinta region in Colorado and Utah and in the Raton Mesa region of Colorado and New Mexico. Smaller occurrences of metallurgical coal have been found in other areas of New Mexico and Montana (see fig. 17).

Other major industrial uses of coal in the West include cement and lime processing, sugar processing, other metals processing, and, in Wyoming, processing of the mineral

Table 22.—Uses and Market Areas of Coal From States With Significant Amounts of Leased Federal Coal

State	Percent use in 1979[a]					Non-utility uses[b]	Out-of-State market area[c]	
	Utility	Industrial/ commercial	Residential	In-State	out-of-State		Utility	Industrial
Colorado	**71.5**	**26.6**	1.9	55	45	CoKe for steel, cememt, sugar processing, metals processing, railroad.	MW (IL, IN, 1A, MO, NB), SC (TX, MS), W (AZ, NM, NV),	MW (IN, 1A, Ml, MN, NB, TN, SD), SC (OK, TX)(W (CA, MT, NM, NV, OR, UT, WA)
Montana	96.0	4.0		11	89	Cement, sugar processing.	**MW (IL, IN, 1A, Ml, MN, WI), SC (TX).**	MW (IL, 1A, MN, WI).
New Mexico	94.0	6.0		60[d]	40	Cement, metals processing (copper), drilling mud, coke for steel (Raton Mesa),	**MW (MO), SC (TX).**	W (AZ, CA, TX)
North Dakota	93.4	6.6		75	25	Sugar processing, leonardite, charcoal briquets.	MW (SD, MN)	MW (MN)
Oklahoma	79.0	21.0		16	84	Lime and cement (16% total) coke for steel (3% total)	MW. SC	MW, SC
Utah	73.3	24.9	1.8	47	53	Coke for steel (about half non-utility use), cement, metals processing.	MW (IN, IL, MO, NB), SC (MS), W (NV, WA).	NW (IL, 1A), W (AZ, CA, CO, ID, MT, NV, OR, WA, WY).
Wyoming	96.3	3.7		22	78	Trona processing, synthetic coke, cement, sugar processing.	MW (IL, IN, 1A, KS, MO, NB, OH, SD, WI), SC (AK, LA, OK, TX), W (CO).	MW (IL, 1A, MN, NB, SD,) SC (OK), W (CO, ID, MT, OR, UT, WA).

[a]percentage breakdown in use categories taken from Office of Technology Assessment State assessment and market survey reports. In-State/out-of-State Percentages calculated from U.S. Department of Energy, *Bituminous and Subbituminous Coal and Lignite Distribution, Calendar* Year *7979* (Washington, D.C.: U.S. Government Printing Office, April 1980).
[b]Non-utility uses compiled from Office of Technology Assessment State assessment and market survey **reports,** information from the Utah and Wyoming Geological Surveys and *Keystone Coal Industry Manual.*
[c]Conpiled **from DOE report cited** In **footnote a.**
[d]**Half of coal used in-State is used to generate electricity (about 30 percent of total coal production) that IS** exported **Out-Of .State**

SOURCE: Office of Technology Assessment.

trona. * Like utilities, most industrial users (other than steel manufacturing) use coal for heat rather than its physical and chemical properties. However, industrial users generally do not require large amounts of coal compared to utilities, so economies in transportation costs through the use of unit-trains cannot be realized. Because of this, high heat content is a premium for industrial and commercial users, and it is the coal regions that produce coal with the highest heat content (Green River-Hams Fork, Uinta and Oklahoma) that have the widest market areas for industrial uses of coal.**

*Trona is a mineral that is refined to soda ash, which in turn is used in the production of glass, woodpulp and paper processing, and manufacture of other chemicals. Southwestern Wyoming contains the only known commercial deposits of trona in the world (Department of Economic Planning and Development 1975 Wyoming Mineral Yearbook, Cheyenne, Wyo.: DEPAD, 1976).

* *One notable exception to the premium on heat content is the mining of leonardite in North Dakota, Leonardite is a soft, earthy coal-like substance that results from the oxidation of lignite. It is a poor fuel (about 4,000 Btu/lb) but is useful as a soil conditioner, and for various industrial uses such as manufacture of oil well-drilling muds, water treatment and stains for wood-finishing.

All of the States that produce Federal coal have either a nearly even division between coal that is used in-State and out-of-State (Colorado and Utah) or export most of the coal that is produced in the State, either as coal (Montana, Oklahoma, and Wyoming] or as coal and electricity generated at mine-mouth plants (New Mexico and North Dakota). Table 22 also shows the current market areas for coal that is exported out-of-State. Wyoming has by far the largest market area of any Western State, with 1979 coal production for utility use going to 14 States and nonutility use to 13 States. In contrast, North Dakota has the most limited market area, because of the low heat content of the coal. Colorado and Utah are the Western States that produce significant amounts of coal for industrial uses (26.6 and 24.9 percent respectively) and the importance of this market is shown by the fact that coal from Colorado and Utah was shipped to more States for industrial uses than for utility uses (16 v. 10 States for Colorado, and 11 v. 7 States for Utah). Chapter 5 discusses the reasons for the differences in market areas between the States in more detail.

Quality of Federal Coal Reserves

User needs related to coal quality have been discussed briefly in the previous section. Except for metallurgical-grade coal (where several additional physical and chemical characteristics are important), the primary parameters of coal quality that are of concern to coal users are: 1) heat content, 2) sulfur content, and 3) ash content.

Heat Content

The large majority of coal is used for its energy value, which is usually expressed as the number of British thermal units (Btu) per pound of coal. * Coals vary considerably in heat content, ranging from less than 5,000 Btu/lb for low rank lignites to more than 14,000 Btu/lb for bituminous and anthracite coals.* (See table 23.) This possible range in heat content of coal can make a substantial difference in the amount of coal that is used.

*A Btu is the quantity of heat required to raise the temperature of 1 lb of water 10 at, or near, its point of maximum density (39.1 °F).

*Coal deposits are classified into 13 different ranks based primarily on criteria involving heat content, volatile matter (coal constituents that are easily vaporized), and fixed carbon (what is left after all volatile constituents have been driven off when coal is heated in the absence of oxygen). Table 23 shows the standards for classification of coal by rank that have been established by the American Society for Testing and Materials (ASTM). Lignite and subbituminous coal are classified according to heat content calculated on a moist mineral-matter-free basis. Bituminous coals are classified based on both heat content and percent volatile matter in the coal. High-volatile bituminous coal (greater than 31 percent volatiles) are classified into three ranks based on heat content. Coal with less than 31 percent volatile matter are classified as low or medium-volatile coal irrespective of heat content, Anthracites have very low content of volatile matter (less than 8 percent), Heat contents reported in this chapter are on an as-received basis, which differ from the heat contents which would be used to rank the coal using ASTM procedures, because corrections have not been made to account for ash content (for lower rank coals) or ash and moisture content (for higher rank coals). The as-received heat content of a coal sample is lower than the heat content that is used to classify the sample according to rank.

Table 23.—Classification of Coals by Rank

Class	Group	Fixed carbon limits, in percent (dry, mineral-matter-free basis)		Volatile matter limits, in percent (dry, mineral-matter-free basis)		Calorific value limits, in Btu per pound (moist, mineral-matter-free basis)[a]		Agglomerating character
		Equal or greater than	Less than	Equal or greater than	Less than	Equal or greater than	Less than	
I. Anthracitic	1. Meta-anthracite	98			2			
	2. Anthracite	92	98	2	8			
	3. Semianthracite	86	92	8	14			Nonagglomerating.[b]
II. Bituminous	1. Low-volatile bituminous coal	78	86	14	22			
	2. Medium-volatile bituminous coal	69	78	22	31			
	3. High-volatile *A* bituminous coal		69	31		14,000[c]		Commonly, agglomerating.[d]
	4. High-volatile *B* bituminous coal					13,000[c]	14,000	
	5. High-volatile *C* bituminous coal					11,500 10,500	13,000 11,500	Agglomerating.
III. Subbituminous	1. Subbituminous *A* coal					10,500	11,500	Nonagglomerating.
	2. Subbituminous *B* coal					9,500	10,500	
	3. Subbituminous *C* coal					8,300	9,500	
IV. Lignitic	1. Lignite *A*					6,300	8,300	
	2. Lignite B						6,300	

[a]Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.
[b]If agglomerating, classify in low-volatile group of the bituminous class.
[c]Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.
[d]It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in the high-volatile C bituminous group.

NOTE: This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon, or have more than 15,500 British thermal units per pound, calculated on the moist, mineral-matter-free basis. Modified from American Society for Testing and Materials (1974).

SOURCE: P. Averitt *Coal Resources of the United* States, *January 1, 1974* U.S. Geological Survey Bulletin 1412 (Washington, D C.. U.S. Government Printing Off Ice 1975)

For example, a powerplant using lignite may burn more than twice as much coal as a powerplant using bituminous coal to produce the same amount of electricity. However, the most important concern of the user in relation to heat content is the cost per unit of energy in the coal (usually expressed as cents or dollars per million Btu) rather than the heat content itself. Thus, a low rank coal that has a lower delivered price per Btu in general compares favorably with a higher rank coal at a higher delivered price.

Sulfur and Ash Content

Sulfur content has become an important aspect of coal quality since passage of the Clean Air Act of 1970, which established limitations on sulfur dioxide emission from coal-fired powerplants. The effect of sulfur emission standards on the demand for Western coal is discussed in more detail in the following chapter on markets. Ash content may be a concern to users if its percentage reaches a level (generally greater than 15 percent) where ash begins to build up in boilers and reduce their efficiency. High ash content also increases the cost of ash disposal after the coal is burned. Boiler design must also take into account the physical and chemical properties of the sulfur and ash in the coal that is used. To some extent, sulfur and ash can be removed from coal before it is burned, however this process adds to the cost.

Variations in Coal Quality by Region

Coal ranks in the Northern Great Plains province fall within a fairly narrow range of lignite and subbituminous coals. In the Rocky Mountain coal province, on the other hand, the different coal regions have a considerable range of coal ranks. The Uinta-Southwest Utah region has the widest range of coal ranks, ranging from lignite to anthracite, although current production is entirely bituminous coal. The diversity of coal ranks in the Rocky Mountain province resulted from the fact that the processes promoting the formation of coal—heat and pressure—have operated with varying degrees of intensity over the geologic history of different deposits. The Northern Great Plains province, on the other hand, has had a relatively simple geologic history in which coal forming processes have generally not been very intense.

Table 24 summarizes some of the important coal quality characteristics of leased Federal coal and major coal fields with Federal leases. The location of these fields is shown in figure 17. The data shown for the Fort Union and Powder River regions shows the range of values for existing leases, whereas data for other coal regions is for the whole coal field, which is generally wider than the range for actual Federal leases in the field.

All coals in the Fort Union region are lignites, whereas Federal coal reserves under lease in the Powder River basin are primarily subbituminous coal. The leased coal in the Decker and Colstrip areas in Montana have higher heat contents than leased reserves in the Wyoming portion of the Powder River basin, but the Colstrip area also has higher sulfur contents. Leased reserves in the Wyoming portion of Green River-Hams Fork region are generally higher quality subbituminous coals [greater than 9,000 Btu/lb) and bituminous coals. Maximum sulfur content is higher than in the Powder River basin, but often coal from higher sulfur seams can be blended with low-sulfur coal to produce coal with acceptable levels of sulfur.

Major fields with leased Federal coal in Colorado and Utah contain mostly bituminous coals, except for the Alton field in southwest Utah which contains leased reserves of subbituminous coal. Leased reserves in the San Juan River region in New Mexico are mostly subbituminous coals with generally higher heat content than in the Powder River basin. There are leased Federal reserves of metallurgical-grade coal in the Uinta region in Colorado and Utah and the Raton Mesa region in Colorado and New Mexico. There are some reserves of lignite under Federal lease in the Denver region of Colorado, but total reserves leased in this area are small and not likely to be developed in the next 10 years.

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Table 24.—Coal Quality Characteristics of Federal Leases and Major Coaifieids With Federai Leases

State	Coal region	No. coal fields[a]	No. fields w/leased Fed. coal	Coal fields with significant concentrations of Federal leases	Quality characteristics of field/Federal leases[b] Ash percent	Sulfur percent	Heat content (Btu/lb)[c]
North Dakota	Fort Union	—	—	—	5.3-10.0	0.2-1.1	5,460-7,345
Montana	Fort Union	26	2	—d	5.7-6.7	0.3-0.5	6,660-6,740
	Powder River	36	4	Decker	3.7-22.1	0.3-0.5	9,100-9,650
				Colstrip	8.0-10.4	0.75-1.0	8,700-9,000
Wyoming	Powder River	12	8	Gillette	{4.8-12.6	0.3-0.5	7,500-8,600}
				Powder River	{		}
				Buffalo	12-30	—	6,500-7,500
				Glenrock	8-12	0.4-0.5	7,300-8,000
	Green River	8	4	Hanna	4.8-18.3	0.4-1.4	9,400-11,460
				Rock Springs	2.8-17.5	0.6-1.2	9,000-13,670
				Little Snake River	14.6	1.7	8,000
	Hams Fork	4	2	Kemmerer	5.3-7.0	0.4-0.6	8,500-9,600
Colorado	Green River	1	1	Yampa	3-20	0.3-1.8	9,800-12,600
	North Park	2	1	—d	2-19	0.2-1.6	6,500-11,300
	Uinta	8	8	Book Cliffs	5-23	0.4-1.7	9,800-13,600
				Danforth Hills	2-1o	0.3-1.4	10,100-12,000
				Somerset	3-11	0.5-0.8	10,000-13,500
	San Juan River	4	2	—d	3-27	0.5-1.3	9,400-14,700
	Denver	2	1	—d	4-45	0.2-1.1	3,600-10,800
	Raton Mesa	2	1	—d	5-22	0.4-1.3	10,200-13,900
Utah	Uinta	15	3	Book Cliffs	6-7	0.4-1.0	12,500-13,000
				Wasatch Plateau	6-7	0.6	12,200-12,700
				Emery	9-20	0.5-2.5	11,400-12,300
	Southwest Utah	4	2	Alton	9	1.1	9,600
				Kaiparowits Plateau	8-14	0.8-1.3	11,200-12,400
New Mexico	San Juan River	31	7	Fruitland	12.6-17,4	0.7-1.0	9,800-10,600
				Bisti	18.5	0.4-0.9	7,500-10,000
				Star Lake	15-20	0.4-0.7	9,400-10,200
	Raton Mesa	1	1	Raton	9-14	0.6	14,300

[a]*Number of* coalfields in each region identified from maps in Criteria for Detetmining viable *Mining* Properties of Exitsing *Federal Coal Leases in the Unitedd States, Final Report* prepared by Colorado School of Mines for the Office of Technology Assessment, March 1980, except for Montana which was taken from Montana Energy Advisory Council, Coal *Development Information Packet* (Helena, Mont.: Office of the Lieutenant Governor, 1974).

[b]Coal qualirty data for North Dakota, Montana and Wyoming represents range of characteristics of existing developed and undeveloped leases in each region; data for other States represents range for the whole coalfield. Data Sources: North Dakota, Montana, and Wyoming — Office of Technology Assessment State assessment reports; Colorado and Utah — Colorado School of Mines Report cited in footnote a; New Mexico — J. W. Shomaker, E. C. Beaumont and F. E. Kottiowski, *Strippable Low-Sulfur* Coal *Resources of the San Juan Basin in New Mexico and Colorado* (Socorro, N. Mex.: New Mexico Bureau of Mines and Mineral Resources, 1971).

[c]As-received values.

[d]Only small amounts of Federal reserves are under lease in these regions

SOURCE: Office of Technology Assessment.

A notable characteristic of all the Western coal fields with leased Federal reserves is their generally low-sulfur content. Only the Emery field in Utah has a maximum sulfur content greater than 2 percent. In contrast sulfur contents exceeding 2 percent are typical in the Midwest and Appalachia, except for West Virginia, which produces a significant amount of low-sulfur coal. Although many Western coal fields have coal seams that exceed 1 percent sulfur, mining is generally concentrated in seams that average less than this percentage. For example, a recent survey of mine expansions and proposed new mines by ICF, Inc., found that only 1 mine will produce coal with more than 1 percent sulfur[5] of 55 mines responding in the Powder River basin and southern Wyoming. All mines responding in the Rocky Mountain coal province will produce coal with less than 1 percent sulfur. In contrast, only 6 percent of the mines surveyed in the Midwest and 25 percent in northern Appalachia will produce coal with less than 1 percent sulfur. *

[5]Percentages calculated from table 11, ICF, Final Report, Survey of United States *Coal* Mine Expansion Plans prepared for the Department of Energy (Washington, D. C,: ICF, Inc. August 1980). The percentage is calculated for only those mines for which coal quality information was reported, which ranged from 71 to 87 percent of all mines included in the survey for the different regions mentioned in the text,

*It should be noted that differences in sulfur content are slightly less when they are compared on a uniform Btu basis.

The same ICF mines survey shows that, except for the San Juan River region, ash content is also generally lower in the West than in the Midwest and Appalachia, although the differences are less than with sulfur. According to the ICF survey, all new mines and mine expansions in the Northern Great Plains and 88 percent of the mines in Utah and Colorado will produce coal with less than 10 percent ash. In the Midwest 68 percent and in northern Appalachia 65 percent of mine expansions and new mines involve less than 10 percent ash. The San Juan River region in New Mexico is the only area with leased Federal coal where ash content seems to be a significant coal quality factor. Eighty-five percent of the mines in the ICF survey from this area will produce coal with greater than 10 percent ash and most of these mines will produce coal that exceeds 14 percent ash. At mines in the San Juan River region of New Mexico, the coal is frequently cleaned to reduce ash before it is burned.

Continued from p. 72.

Because Western coal has generally lower heat content than coal from Appalachia and the Midwest, its effective sulfur content is higher than a comparison based on percentages would indicate. Table 12 of the ICF survey cited above compares mines according to pounds of sulfur per million Btu. In the Northern Plain, for example, 67 percent of the mines will produce coal with less than 0.83 lb sulfur per million Btu (coal less than this can comply with the 1970 new source performance standards with small amounts of sulfur reduction) compared to 30 percent of the mines in northern Appalachia. Western coal still has a lower sulfur content on the whole than Eastern coal, but the difference is not as great as sulfur percentage comparisons suggest.

In general, the quality characteristics of leased Federal coal reserves would not prevent development of the coal, based on user needs, provided the coal can be sold at a price that is competitive with coal produced from other mines or regions. There are a few exceptions to this generalization. All Federal leases in the Fort Union region and about 50 million tons per year potential production capacity from Federal reserves under lease and preference right lease application in the Wyoming Powder River basin are suitable only for onsite development because of low heat content. * Similar constraints for lease development exist for NERCO's Cherokee lease block in the Little Snake River field in southern Wyoming and several leases in the Denver region of Colorado.

The demand for metallurgical coal in the West is expected to remain relatively stable during the next decade because most coal currently produced is used at steel plants in the region. Production of metallurgical coal could increase slightly to meet expanded foreign exports. The availability of Federal and non-Federal coal from the metallurgical coal areas in the West is expected to meet demand in the foreseeable future.

*Forty-five million tons out of the 50 million tons are unlikely to be in production by 1991, but could come into production in the 1990's.

Geologic Conditions and Mining Methods

The diversity of geologic and topographic conditions in which coal is found in the West requires a variety of mining methods. This section describes the different geologic conditions in the West that affect the choice of mining methods and the ease or difficulty of mining coal. Chapter 11 describes in more detail the surface and underground mining methods that are currently used in the West and analyzes the potential for use of more advanced mining technologies.

Table 25 summarizes data on seam thickness and dip (the inclination of a coal seam expressed as degrees from the horizontal) in the major coal regions in which Federal coal is leased and the dominant mining methods and common mining problems encountered. The thickness and dip of a coal seam affect the ease and cost of mining. In most of these regions coal seams can be very thick. Two regions, the Powder River and Hams Fork, have single coal seams that exceed 100 ft. All other

Table 25.—Geologic[a] and Mining Characteristics of Major Federal Coal States

Coal production region	Coal thickness (ft)	Typical seam dip	Mining methods	Mining problems[b]
Fort Union (ND, MT)	2-37 (ND) 10-50 (MT)	Less than 30	Surface only[c]	Highwall stability
Powder River (MT, WY)	4-80 (MT) 10-220 (WY)	Less than 40	Surface only[c]	Highwall stability. Burned coal.
Green River-Hams Fork (WY, CO)	2-40 (CO) 5-110 (WY)	1-15° (CO) 10-50”, some areas less than 6° (WY)	Surface and underground in Green River region; surface only in Hams Fork region at present.[c]	Steep dips create difficulties in Hams Fork and Hanna areas in Wyoming and subsidence from previous underground mining has been a problem in the Rock Springs area, Wyoming. No serious problems in Colorado because dips are generally less steep than in Wyoming.
Uinta-southwest Utah (CO, UT)	1-30 (CO) 3-25 (UT)	Less than 10” (Uinta) generally less than 70 but UP to 15” (SW Utah).	Mostly underground in Uinta region at present. No present production in southwest Utah, but both surface and underground possible.	Uinta area: some methane, floor and roof stability, faulting, steep dips (CO), sandstone dikes (CO), thick overburden (UT and CO), variable dips (UT), water (UT, CO), rugged terrain (UT, CO). Southwest Utah: discontinuous beds, burned coal, undulating roof, water, difficult terrain, splits and partings in coal.
Raton Mesa (CO, NM)	3-10 (CO) 6-13 (NM)	Less than 3“	Surface and underground.	Colorado: roof stability, igneous sills and dikes, some methane. New Mexico: no serious problems.
San Juan River (CO, NM)	1-40 (CO) 3-50 (NM)	Generally 2-6” up to 20°	Surface and underground in Colorado. Surface only in New Mexico at present, but underground possible in future.	Colorado: rugged topography. New Mexice: steep dips, faulting.
Oklahoma	1-7	Generally less than 3“ but up to 80°	Surface and underground.	Steep dips, methane, abandoned workings, thin seams, undulating beds, faulting.

[a]*Data drawn primarily* from tabular summary of conventional coal mine **development models, western U.S. in Criteria for Determining viable** *Mining Properties On Existing Federal Coal Leases in the Western United States, Final Report* prepared by the Colorado School of Mines for the Office of Technology Assessment, March 1980. Some additional data on coal rank and seam dips comes from Summary *Geologic Description of the United States Coal Provinces and Coal Regions, Prepared from Existing Data,* prepared for Office of Technology Assessment by Earth Satellite Corporation, February 1980.

[b]Geologic and topographic conditions that make the **process of mining difficult, as distinct** from environmental regulations that may affect the mining process. Problems listed here do not **occur at all mines in a region; individual mines will rarely have more than a few of the problems listed here, and many have none. Mining problems listed here were identified in** *Criteria for Determining* Viable *Mining Properties on Existing Federal Coal Leases m the Western United States, Final Report,* prepared by the Colorado School of Mines for the Office of Technology Assessment, with some supplemental information obtained from the Office of Technology Assessment State assessment reports.

[c]There has been underground mining in the Fort Union, powder River and Hams Fork **regions in the past, but such** production is not expected In the near future. In the longer term, in situ gasification may result in the development of underground reserves in the Powder River Basin. Coal in the Hams Fork region has a higher heat content than the Powder River Basin, but steep dips make underground mining difficult, Hydraulic mining, which uses a jet of high-pressure water for cutting coal has been proposed for this region on an experimental basis. Hydraulic mining has been successfully used In Canada on coal seams with dips 25 to 50” (R. L Raines, “Underground Mining of Coal” *Mining Congress Journal,* February 1976, pp. 24-27,

SOURCE: Office of Technology Assessment.

regions have coal seams that range up to 30 to 50 ft, except Oklahoma and the Raton Mesa.

Thick coal seams are advantageous for surface mining because less overburden must be removed per ton of coal compared to the thinner coal seams (generally less than 6 ft) that are mined in the Midwest and Appalachia. On the other hand, in underground mines recovery of coal reserves is considerably decreased where coal seams exceed 10 or 12 ft in thickness, although full seam extraction of coal seams 20 to 30 ft thick is currently achieved in mines in France and Poland. However, the high costs of the methods used to achieve high recovery rates in thick coal seams has prevented use of these methods in the United States where underground coal mines must compete with inexpensive surface mined coal.

Coal seams in the West range from horizontal to vertical, but there are considerable regional differences in the typical dips of coal seams (see table 25). The Fort Union, Powder River, Raton Mesa, and San Juan River coal regions have generally flatlying beds which are easily surface mined. Difficulties may be encountered in the Colorado portion of the Raton Mesa region because of factors other than dip (see table 25). The Green River and Southwest Utah regions and the Oklahoma portion of the Western Interior coal region are generally characterized by coal seams that dip less than 70, but some coal leases in the Rock Springs field in the Green River region and in Oklahoma have more steeply dipping beds that can create difficulties for mining. The Hanna field and the Hams Fork coal region in Wyoming typically dip more than 100, The dipping seams in the Hanna field, located in the northeast part of the Green River region (see fig. 17) present some of the most difficult surface mining conditions in the United States, and special methods of using draglines to handle overburden have been developed.

At this time, only surface mining methods are used to produce coal in the Powder River and Fort Union regions because thick seams and low heat content make underground mining economically unfeasible, In-situ gasification in the Powder River region may permit development of deeper coal beds (more than 500 ft of overburden) in the future. All production at present from the Hams Fork region in Wyoming and the San Juan River region in New Mexico is from surface mines, but several operators are planning or considering underground mining in these areas because the higher heat content of these coals makes it economically feasible to do so. Coal in the Uinta and Raton Mesa regions and the Colorado portion of the San Juan River region is currently mined by both surface and underground methods, Mining in the Utah portion of the Uinta region is almost entirely underground, and there is no mining in the Southwest Utah region at this time, although both surface and underground mining is possible.

Geologic conditions that make mining difficult are also very site specific, but there are definite regional differences in the extent to which problems can be expected to occur. The Fort Union, Powder River, and San Juan River regions generally have few, or minor mining problems, although highwall stability may be a problem locally in the Northern Great Plains. Steep dips in the Hams Fork Region and the Rock Springs and Hanna fields in the Green River regions of Wyoming create difficulties for both surface and underground mining as mentioned previously. In underground mines a variety of difficulties can be encountered in the Uinta, Southwest Utah, Raton Mesa regions and in Oklahoma. The number and relative importance of underground mining problems varies between these regions (see table 25) but include: methane hazards, roof and floor instability, dikes and intrusions in the coal, faulting, steep dips, thick overburden, variable dips, thin seams, undulating or discontinuous beds, splits and partings in coal, water, and burned coal.

Mining conditions found on Federal leases include almost the whole range of possible combinations that make mining easy or difficult. The Gillette field in northeastern Wyoming presents some of the most ideal mining conditions found anywhere, with thick, flatlying coal seams under shallow overburden. Underground mining conditions on Federal leases in western Colorado and central Utah range from very favorable to very difficult, Among the most difficult underground mining problems that are sometimes encountered are: overburden that exceeds 3,000 ft, seam dips that approach 350, extreme fracturing and faulting in both the coal seams and the confining rock strata, and unstable floor and roof conditions. Chapter 11 examines in more detail geologic conditions as they affect underground mining methods.

Summary

Leased Federal coal reserves encompass a wide range of coal types, qualities, and geologic conditions for mining. This section summarizes some of the important points made in this chapter.

1. Federal coal leases are located in 14 States, but the vast majority of leased Federal coal reserves (98 percent) are located in six Western States: Colorado, Montana, North Dakota, New Mexico, Utah, and Wyoming. Coal reserves under lease and PRLA are very unevenly divided between these six States. Wyoming has by far the greatest reserves under lease and PRLA (56 and 43 percent respectively of total reserves under lease and PRLA in the six States). Wyoming and Utah together contain more than three-quarters of the reserves under Federal lease, and Wyoming, New Mexico, and Colorado contain nearly 90 percent of the reserves under PRLA. Most of the reserves under lease and PRLA (about 70 percent for both)* can be mined by surface methods, but a majority of the leased reserves in Colorado and Utah must be mined by underground methods.

2. Although the Federal Government owns approximately 60 percent of the coal reserves in the six major Federal coal States, production from Federal coal leases between 1957 and 1979 fluctuated between only 20 and 45 percent of total production. Since 1973 the quantity and percentage share of Federal coal production in these States has shown a general increase. However in 1979, even though total Federal production was more than eight times higher than in 1970, its percentage share of all production in the six States was less than in 1960. During the next decade, Federal coal production will probably increase at a higher rate than non-Federal coal production because of the large increases from the Powder River region where the Federal Government owns a large percentage of coal reserves.

3. The quality of coal reserves presently under lease and PRLA does not appear to impose any serious limitations for meeting the demand that is likely for Western coal over the next 10 to 15 years. Most leased reserves have low sulfur and ash content and are suitable for use by utilities, which constitute the single greatest user of Western coal. All Federal leases in the Fort Union region and about 50 million tons per year potential production capacity from Federal reserves under lease and PRLA in the Wyoming portion of the Powder River basin are probably suitable only for onsite development for power or synfuels plants because of their low heat content. (However, the majority of Federal reserves under lease are of sufficiently high quality to be exported out of the producing State.) The demand for metallurgical coal in the West is expected to remain relatively stable during the next decade and even when possible increases in demand for foreign export are considered, the availability of Federal and non-Federal metallurgical coal in the West appears to be adequate for the foreseeable future.

‘Table 19 shows that only 61 percent of the reserves under PRLA are surface minable, but if the subbituminous underground reserves in the Powder River basin are subtracted, as discussed earlier, the percentage changes to 71 percent.

CHAPTER 5

Markets and Projected Demand for Federal Coal

Contents

List of Tables

List of Figures

CHAPTER 5

Markets and Projected Demand for Federal Coal

The concentration of Federal coal resources in the West means that the demand for Federal coal is closely tied to the demand for Western coal. The demand for Western coal is determined by the dynamic interaction of various economic and institutional factors that affect: 1) coal use in the far West, 2) the competitive position of Western coal in energy demand centers in the Midwest, North-Central and South-Central United States with respect to other coal provinces (the Gulf Coast and Interior provinces primarily), and 3) the competitive position of Western coal with respect to competing fuels such as oil, gas, and uranium.

This chapter first examines in a general way the factors that affect the overall demand for coal, and then looks a little more closely at the effect these factors have on the market situation for Western coal as of 1980. The impact that likely or possible trends could have on Western markets through to 1990 are then examined in some detail. Next, the major market advantages and disadvantages of coal produced from the six major Federal coal-producing States (North Dakota, Montana, Wyoming, Colorado, Utah, and New Mexico)* are summarized with an analysis of the relative competitive position of coal production from these States in different regions of the country. Finally, the results of recent market studies and forecasts of the demand for Western coal in the period 1980 to 1990 are analyzed in relation to demand estimates that were developed by OTA to evaluate potential production from existing Federal coal leases. The chapter concludes with a general look at the range of possibilities for demand for Western coal in the context of total U. S. coal demand between 1980 and 2000.

*Arizona produced almost as much coal in 1979 as New Mexico, and thus ranks as a major Western coal-producing State. However, all production in Arizona is from Indian land and is thus not considered in this chapter.

Factors Affecting the Demand for Coal

The demand for coal is primarily the result of individual consumers or users making choices based on suitable quality and the price of coal from different regions and, when other fuels can be substituted for coal, the price of alternative noncoal energy resources. Although these relative prices may be significantly affected by "nonmarket" factors, such as Government policy, in this chapter the term "market demand" refers to least-cost energy purchasing decisions made by users,** "Nonmarket" factors in the form of Government policy can have a significant impact on the demand for coal, but a distinction can be made between Government policies that: 1) change the institutional context of the market system and 2) directly stimulate the demand for coal. Policies in the first category include most environmental regulations that change the relative cost of using coal from different regions. The market system itself makes the necessary adjustments to the new institutional context. Thus, the mar-

** It should be noted that coal quality factors affect purchasing decisions and may result in the purchase of higher cost coal. For example, higher delivered cost of Western low-sulfur coal East of the Mississippi compared to local high-sulfur coal has been accepted by some utilities because retrofitting old plants with stack gas scrubbers was considered too costly and risky due to uncertainties surrounding the reliability of available scrubbers. However, even in this case the decision to purchase more expensive coal is based on the belief that in the long run the cost of generating electricity would be cheaper than the use of less expensive high-sulfur coal.

ket demand for coal changes, but shifts in the level of demand and regional shifts in coal production are based on least-cost energy purchasing decisions. Government policies that directly stimulate demand for coal include Government subsidies for a commercial coal-based synthetic fuels industry and the off-gas requirements of the Powerplant and Industrial Fuel Use Act. * At the present time Government intervention in the market system to directly increase demand for coal forms a small percentage of coal use in the United States. However, if Government subsidies are seen as necessary to develop a large-scale coal-based synthetic fuels industry, this situation could change.

Table 26 lists some of the major factors that affect demand for coal. These factors fall into three broad categories: 1) user needs, 2) costs (mine mouth, delivered, and costs of converting into useful energy), and 3) institutional constraints on production.

User Needs

User needs are the primary determinant in the demand for coal. High levels in the electrical growth rate, high steel production, and extensive conversion of industrial and electric utility boilers to coal from oil and gas will all mean an increase in coal demand. High levels of coal-based synthetic fuels development and high overseas demand for coal will also increase coal markets. The important role that coal is expected to play in the U.S. energy picture is largely the result of the high cost and less certain availability of oil. Coal's main competitors as substitutes for oil and gas are nuclear power and energy conservation. ** Low levels of energy conservation and nuclear power growth would contribute to increased demand for coal.

Coal markets are also affected by the extent of substitutability of alternative sources to meet user needs. Electric utility needs can be met by oil, gas, uranium, conservation* and a wide range of coal qualities. For a new powerplant the primary determinant in utility choice of fuels is the relative cost of producing electricity. Once a choice has been made and a powerplant built to meet the specifications of the chosen fuel some substitutions become impossible (i.e., nuclear to coal) and most become costly (i.e., oil or gas to coal and shifts from one coal type to another). On the other hand, there is little substitutability in the demand for metallurgical-grade coal.**

Cost Factors

For a coal producer to sell his coal, he must usually produce it at a price such that delivered cost per Btu to the consumers (mine plus transportation cost) is lower than the delivered cost per Btu of coal offered by competing coal producers. If the offered price is higher, then the coal must be more attractive to the prospective buyer, either because the coal quality characteristics are more suitable for his need, or for some other reason such as lower costs to produce electricity or greater assurance of reliable delivery.*** Basic mine

*The off-gas requirements in this act actually have elements of both kinds of policies: the law requires conversion from gas to coal even if it is cheaper for the utility to continue with gas (i.e., least cost energy purchasing decisions are not allowed), but on the other hand, once the shift is made to coal, the open market will determine where the utility buys its coal based on a narrower set of least cost considerations. These requirements have now been repealed by Congress (see third footnote, next column),

**If conservation reduces the total level of energy consumption which is served by oil and gas, there is less need to substitute other energy sources. Without conservation the demand for coal as a substitute to oil and gas would be higher, and it is in this specific sense that conservation is a competitor to coal.

*Conservation in this context refers to utility investments in activities that reduce total demand or reduce peak demand (such as time-of-day pricing, load management, insulation loan programs) because they are cheaper than investments that increase generating capacity. This kind of conservation is different from conservation by electricity users that is purely in response to increased cost of electricity. The latter form of conservation reduces the amount of electricy a utility needs to produce, but does not fulfill the needs of the utility as a business.

**To a limited extent low-sulfur, low-ash coals that do not have normal coking properties can be blended with metallurgical-grade coal to produce coke, Newly developing technology for production of "form coke" can take a wide range in rank of coal, although sulfur and ash content are still important.

***The Powerplant and Industrial Fuel Use Act which mandated conversions to coal from gas in utility and large industrial boilers may result in the choice of coal as a fuel where cost comparisons would indicate staying with gas. However, the impact of this law has been reduced by the Omnibus Budget Reconciliation Act passed by Congress in August 1981 which repealed the ban on use of natural gas in 1990 in section 301 of PIFUA, Instead, utilities that use natural gas as a primary fuel are required to develop conservation plans to reduce current annual power production attributable to natural gas by 10 percent within 5 years.

Table 26.—Factors Affecting Market Demand for Western Coal

Factor	Markets increase when factor is:	Markets decrease when factor is:	Current market situation in West	Current or probable trends (1980-90)
User needs				
Utilities				
Electrical growth rate	High (>5%)	Low (<3%)	Low	Low - moderate
SO_2 emissions standards	1970 NSPS, limits on total emissions	1979 NSPS or no emissions limits	Current standards reduce demand compared to 1970 NSPS.	Amendments to Clean Air Act could change situation either way.
Competing energy sources				
Cost of oil & gas	High	Low	High	Higher
Nuclear power growth	Low	High	Low (in West)	Low (in Western coal's market area)
Industrial				
Steel production	High	Low	Low	Low
Industrial boiler conversions	High	Low	Low	Low - moderate
Synthetic fuels development	High	Low	Low	Low - moderate
Foreign export	High	Low	Low	Possible increase
Costs[a]				
Mine (FOB) cost per million Btu			Overall:[b] low (Northern Plains) moderate (Rockies)	Little change
Equipment cost, operation & maintenance	Low	High	Moderate	Little change
Labor	Low	High	Low - moderate	Little change
Reclamation	Low	High	Low	Little change[c]
Health & safety	Low	High	Low - surface mines High - underground mines	Little change Little change
Royalty rates	Low	High	Low - existing leases High - new leases	Increases as existing leases come up for adjustment
Severance taxes	Low	High	Low - high	Some increase or decrease at State level is possible
Delivered cost				
Transportation	Low	High	Low (mine-mouth plants) High (export)	Additional increases likely with rail deregulation and increased fuel costs. Possible decreases in some localities with slurry pipelines
Technologies for clean burning of coal (cost)	High[d]	Low	Moderate - high	Decreases possible through increased experience and technological improvements
Institutional constraints at mine	Low	High	Institutional constraints are highly site specific. See chs. 8 and 10 for specific examples.	

[a]For utilities and industrial boiler users the essential cost factors are delivered price and the cost of technologies for clean burning of coal. For the steel industry cost comparisons are restricted to coals that have characteristics that are suitable for making coke.
[b]Relative to the cost of Midwestern coal.
[c]Little change in reclamation costs is likely in the West, but proposed amendments to the Surface Mining Control and Reclamation Act that would give States more flexibility in setting reclamation standards could decrease markets for Western coal because the relatively high reclamation costs in the Midwest resulting from enforcement of the act might be reduced,
[d]High costs for technologies promoting clean burning of coal (coal cleaning, flue gas desulfurization and fluidized bed combustion) favor Western coal because of its generally low sulfur and ash content. Decreases in costs favor increased use of high sulfur Midwestern coal. Reliability of these technologies is also an important factor, with low reliability favoring Western coal and high reliability favoring Midwestern coal.

SOURCE: Office of Technology Assessment

costs include the cost of equipment purchase, operation and maintenance, labor, and the cost of reclamation and improving health and safety conditions for miners. Additional costs may be added as a result of royalties that must be paid to the owner of the coal and severance taxes imposed by States in which the coal is mined. Low costs in all these factors relative to other coal producers improves the competitive position of a coal deposit. Heat content can make an important difference in the unit-energy cost of coal. At any given price, all other things being equal, coal with a higher heat content is cheaper to use for a given job than coal with a low heat content.

Coal is a commodity with a low specific value compared to other commodities, often costing less than a cent per pound at the mine and sometimes considerably less. Consequently transportation costs represent a substantial portion of the delivered cost of coal if the user is a significant distance from the mine. Low transportation costs relative to other coal producers increase marketing potential. Transportation costs can bean important limiting factor where coalfields are distant from existing networks that transport coal. For example, the high cost of building a coal transportation infrastructure to connect the coalfields in southwest Utah with existing networks is an impediment to developing this area.

Institutional Constraints

In some situations a coal reserve may be available for development at a cost that is competitive with coal from other sources, but the coal cannot be mined because of environmental reasons, labor or equipment shortages, or possibly limited or nonexistent transportation capacity. An example of an environmental threshold that might eventually delay or possibly limit expansion of coal development appears to exist in North Dakota. All currently proposed mines in North Dakota are associated with proposed nearby power and synthetic fuel plants. Operation of all currently permitted plants may exceed the "prevention of significant deterioration" air quality increments for sulfur dioxide (SO_2). If this is the case, the level of mine development may be limited as well. (Additional discussion of this situation can be found in ch. 10.) Labor shortages and limits to transportation capacity are usually relatively short-term conditions that can be corrected in the presence of strong demand for coal from a region. Specific transportation and environmental issues affecting Western coal development are discussed in more detail in chapters 8 and 10, respectively.

Institutional constraints are more significant in their impact on production at a specific locality than on the demand for coal in general, Unless institutional constraints limit production in a large number of coal-producing regions, demand is met by increased production from regions that do not experience constraints. Such shifts in production may result in some cost increases, but unless production is constrained in a number of regions, causing rapid increases in production of marginal coal reserves that cost more to mine than existing mines, such cost increases are not likely to be large. [1] If reasonable environmental and socioeconomic thresholds set limits on coal production in an area, cost increases resulting in shifts in coal production to other areas can be considered part of internalizing the environmental and social costs of mining coal. *

[1]The cost impact of such regional shifts in production depends on both changes in mine mouth cost and transportation cost. ICF has noted that moderate shortfalls in some regions can be compensated for by increased production from nearby regions which are less constrained and which have adequate reserves of comparable coals available, but that if constraints are widespread, the net costs to society can be high (ICF, Inc., Analysis and Critique of the Department of Energy's August 7, 1980 Report Entitled "Preliminary Nationcd and Regional Coal Production Goals *for* **1985, 1990 and 1995,** Washington, D. C.: ICF, Inc., October 1980).

*However, it must be recognized that there may be considerable disagreement as to what constitutes a "reasonable" environmental or socioeconomic threshold at a specific location.

Trends in Factors Affecting the Demand for Western Coal: 1980-90

The last two columns in table 26 give a general view of the current market situation in the West with respect to the factors affecting the demand for coal and identify likely or possible trends in these factors in the period from 1980 to 1990. The following text discusses only the most salient factors listed on this table with respect to Western coal.

Electrical Growth Rate

Electric utilities are by far the most significant user that will be affecting the demand for Western coal. In 1979 utilities purchased 70 to 96 percent of the coal produced in the major Western Federal coal-producing States (see table 22, ch. 4). The electrical growth rate will probably be the single most important factor affecting demand for coal from Western States during the next 10 years. The electrical growth rate in the last few years has declined significantly compared to rates following World War II. The average growth rate of total net generation of electricity from 1945 to 1973 was 7 percent. Average annual growth since 1973 has slowed substantially and has averaged less than 2 percent during the last few years (total U.S. consumption of electricity in 1979 was 1.9 percent higher than in 1978 and in 1980 the increase was 1.4 percent).

The decrease in the electrical growth rate has been largely the result of conservation in response to increasing costs of electricity, although the economic situation of the past few years has been an important factor in recent very low growth rates. This decline in the electrical growth rate is a major reason for the decreases in projections for demand for Western coal over the last few years. For example, the Department of Energy's (DOE) 1990 production goals for the western Northern Great Plains (which also includes southern Wyoming) dropped from 529 million tons in the 1978 forecast to 336 million tons in the 1980 preliminary forecast. Most of this drop can be attributed to a reduction in the electrical growth rate used in the forecast.

Efforts to project longer-term electricity growth rates have historically not been very accurate, but table 27, which compares projected growth rates over the last decade, show there has been a consistent downward trend in projected growth for similar time periods in the future. Table 27 shows that recent electrical growth projections for the period from 1979 to 1985 range from 2,5 to 4.1 percent. The low projections are higher than growth rates in the past few years, reflecting a belief that an economic upturn will increase demand for electricity. The upper range of 4. I percent projected by the National Electric Reliability Council (NERC) in July 1980 is considered by a number of observers to be somewhat high. The National Coal Association (NCA), for example, uses the NERC electrical growth rate for their high projection and an electrical growth rate of 3.5 percent for their most likely projection of U.S. coal production.' Also the electrical

'National Coal Association, NCA Long-Term Forecast (Washington, D. C.: NCA, March 198 1).

Table 27.—Comparison of Historical Forecasts of Annual Growth Rate of Total Electric Generation

Scurce and year of study	Projected growth rate (percent)	Time period
U.S. Energy Outlook–1971	7.2	1971-85
Department of the interior—1972	6.1	1971-2000
Oak Ridge National Laboratory–1973	4.4	1974-85
Lawrence Livermore Laboratory— 1974	5.6	1974-85
Technical Advisory Committee—1974.	6.0	1974-85
Oak Ridge National Laboratory—1975	5.1	1974-85
Westinghouse—1975	5.0	1974-85
Electrical World—1975	5.8	1975-85
Exxon Co.—1977	4.8	1977-90
EIA's Annual Report to Congress—1978	4.7	1977-85
CONAES–1978	0.7-3.2	1975-2010
National Electric Reliability Council —July 1980	4.1	1979-89
National Electric Reliability Council —July 1981	3.7	1981-90
Department of Energy—August 1980	3.0	1978-85
ICF, Inc.—November 1980	3.5	1979-85
ICF, Inc.—November 1980	3.0	1985-90
Economic Regulatory Administration and Energy Information Administration—December 1980	2,5	1979-85
1980 actual[a]	1,4	1980

[a]Rate of increase experienced for the first 47 weeks of 1980 over corresponding period of 1979.

SOURCES: Forecasts from 1971 to 1978 from table 39, U S Department of Energy, Short *Term Energy Outlook,* DOE/EIA-0202/2 (Washington, DC U.S. Government Printing Office, February 1980) Projections of the Demand and Conservation Panel of the Committee on Nuclear and Alternative Energy Systems as scenario B cited in Science, Apr. 14, 1978, p. 151

National Electric Reliablilty Council, 1980 Summary of *Protected Peak Demand, Generating Capability and Fossil Fuel Requirements for the Regional Reliability Councils of NERC* (Princeton, N. J.: NERC, July 1980), Calculated from table 9 It should be noted that this is a drop from the 4 4-percent rate projected by the Regional Councils in their April 1980 reports to the U S. Economic Regulatory Administration,

National Electric Reliability Council, *Electric Power Supply and Demand 1981-1990* (Princeton, N.J.: NERC, July 1981)

Department of Energy, *Preliminary National and Regional Coal Production Goals for 1985, 1990 and 1995* (Washington, D C DOE, Aug 7, 1980), From table 19

ICF, Inc., *Forecasts and Sensitivity Analyses of Western Coal Product/on,* prepared for Rocky Mountain Energy Co (Washington, D.C.: ICF, Inc., November 1980). From table 3-2, app A

ERA and EIA growth rate taken from table 1, Department of Energy, *Proposed Changes to Generating Capacity 1980.89 for the Contiguous United States, DOE/RG-0047* (Washington, D C DOE, December 1980,) The 25 percent was derived by combining the esti. mates by the Economic Regulatory Administratlon of 21 percent from 1979 to 1983, and latest estimates by the Energy Information Administration of 32 percent from 1978 to 1995 growth rate projected by NERC in July 1981 was reduced by 10 percent from their earlier projection, to 3.7 percent.

There are analysts who expect the electrical growth rate to continue to decline in the future. For example, the Solar Energy Research Institute (SERI) projects an electrical growth rate of 0.4 percent annually between 1978 and 2000 if cost-effective efficiency investments are made (excluding investments in solar).[3] According to this study, construction programs already underway could support such an increase in demand over the next 20 years even if: 1) no plants are brought on line after 1985, 2) all fossil plants built before 1961 are retired, and 3) 80 percent of all oil- and gas-burning generating plants are retired. The SERI study also concluded that vigorous onsite solar investments (active and passive solar space and water heating) combined with extensive development of cogeneration and onsite wind and photovoltaic systems could result in a negative growth rate in the demand for electricity between now and the turn of the century.

More important than the overall electrical growth rate in the United States are the regional growth rates in the potential market areas for Western coal. Recent projections by NERC, NCA, and ICF all assume electrical growth rates (EGR) in the far West that are lower than, or near average compared to the United States as a whole. For the period 1980 to 1990 NERC projects an EGR of 3.8 percent in the West compared to a national average of 3.7 percent. ICF projects a slightly lower rate for the West (2.8 v. 3.0 percent from 1979 to 1990) and NCA projects a significantly lower rate in the West than the national average (2.9 v. 3.5 percent) for the same time period.[4] On the other hand, all three of these sources project higher than average electrical growth rates in the Midwest and South-Central United States, both important market areas for Western coal. In much of this area coal from the Gulf Coast lignite province and the Midwest compete with coal from the major Federal coal States.

Another important factor affecting the utility demand for Western coal is the regional growth rate in coal-fired generation. In some areas in the United States, such as in the Midwest, where coal is already meeting most generation requirements, increases in coal demand are fairly directly tied to the growth in demand for electricity. However, in areas like the South-Central United States where coal-fired capacity is being added in a system primarily dependent on more expensive fuel (i.e., oil or natural gas), demand for coal may increase through replacement of oil and/or gas base load generation even if there is no total generation growth. Regional growth rates in coal-fired generation between 1980 and 1990 are projected by NERC to be 3.1 percent in the West (WSCC and MARCA regional reliability councils) and 10.0 percent for the South-Central United States (ERCOT and SPP reliability councils).* NCA projects higher growth rates for essentially the same time period (1979-90) of 5.0 percent in the West and 13.1 percent in the South-Central United States.

It is apparent that the electrical growth rate and conversions from gas to coal in the South-Central United States will be a major determinant in the rate of increase in the demand for Western coal. In 1979 the South-Central United States consumed 26 percent of total Western coal production used by utilities. ** NCA projects that 40 percent of the

[3]House Committee on Energy and Commerce, Report on Building a Sustainable Future, prepared by the Solar Energy Research Institute (Washington, D. C.: U.S. Government Printing Office, April 1981), p, 152,

[4]The geographic areas for these projections do not entirely coincide. The NERC projection is for the Western Systems Coordination Council (calculated from table 19, Electric Power Supply and Demand 1981-1990 (Princeton, N.].: National Electric Reliability Council, July 1981). The ICF projections cover approximately the same area as the WSCC but include parts of Montana and New Mexico that are in other regional reliability councils (calculated from table 3-2, app. A, Forecasts and Sensitivity Analysis of Western Coal Production, Washington, D, C.: ICF, Inc., November 1980). The NCA projections include both the WSCC and the Mid-Continent Area Reliability y Coordination Agreement (MARCA) which covers the upper Midwest (see footnote 2 for source).

*ERCOT covers most of Texas and SPP includes north Texas, eastern New Mexico, Oklahoma, Kansas, Arkansas, Louisiana, and the western parts of Missouri and Mississippi, See footnote 4 for sources of projections cited in this paragraph.

**Total Western coal production includes production from the Northern Plains, Rocky Mountain, and Gulf Coast coal provinces, the western part of the Interior coal province, Washington State, and Alaska.

coal produced in the West in 1990 will be used in the South-Central region, and NERC projects that 47 percent of Western coal production for utilities will be used in this area. The reasons for this projected large increase are: 1) replacement of gas with coal-fired generation, as originally required by the Powerplant and Industrial Fuel Use Act (PIFUA]; and 2) higher gas prices. Increases in the availability of natural gas since passage of PIFUA has decreased some of the pressures to switch from gas to coal, and there remains some uncertainty as to how much of a shift from gas to coal will actually occur in this region by 1990,

Sulfur Reduction Standards

Before passage of the 1970 Clean Air Act, sulfur content of coal was not a significant factor affecting utility coal purchase decisions. The 1970 new source performance standards (NSPS) for $S0_2$ that set a maximum emission rate of 1.2-lb/million Btu, created a large market for "compliance" coal (i.e., coal that could be burned without stack gas scrubbing and meet the 1.2-lb standard). * A significant amount of the increased demand for Western coal between 1970 and 1979 can be attributed to the fact that Western coalfields could produce compliance coal that had a delivered price in the Midwest that was lower than the delivered price of high-sulfur Midwestern coal when the added cost of scrubbing the high-sulfur coal was factored in.

The 1977 Clean Air Act Amendments, which required sulfur reduction for all coals burned by utilities, significantly reduced the market advantage enjoyed by low-sulfur Western coal under the 1970 NSPS for SO_2. The 1979 NSPS for SO_2 which apply to new powerplants, establish a dual standard for sulfur reduction based on both sulfur content and maximum allowable emissions of SO_2. ** If 70-percent sulfur reduction will result in an emission rate of less than 0.6 lb SO_2/million Btu, a higher sulfur reduction is not necessary. All higher sulfur coals must have 90-percent reduction in sulfur, but emission of SO_2 cannot exceed the 1970 NSPS of 1.2 lb/million Btu.[5] For "high" sulfur coal, this translates into a maximum of 6.0 lb sulfur/million Btu (90-percent reduction of this amount equals 1.2 lb SO_2/million Btu). For low sulfur coal this translates into a maximum of 1.0 lb sulfur/million Btu (70-percent reduction of this amount equals 0.6 lb SO_2/million Btu). Most current production in the West would qualify for a 70-percent sulfur reduction rate.

The cost of stack gas scrubbing for Western low-sulfur coal is generally lower than for high-sulfur coal because scrubbing processes for low-sulfur coal (mostly dry) are cheaper than wet processes needed for high sulfur coal. However, this advantage is largely offset by allowances in the present regulations that give credit for sulfur reduction by precombustion cleaning (i.e., sulfur reduction by cleaning can reduce the percentage of sulfur reduction required by stack gas scrubbing). According to studies by the Bureau of Mines, mechanical cleaning of coal from northern Appalachia and the Midwest can result in average reductions in sulfur of 33 and 23 percent respectively.' This means that sulfur reduction by stack gas scrubbing would typically need to range from 57 to 67 percent

*This translates into a coal sulfur content of 0.6 lb/million Btu since that amount of sulfur would convert to 1.2 lb of SO_2.

**The final 1979 NSPS were published on June 11, 1979 (44 Federal Register 33613-33624) but apply to all electric utility steam generating units for which construction commenced after Sept. 18, 1978.

[5]The 1979 NSPS have been challenged in court on the grounds that there was irregular ex parte communication during their formulation. The regulations have been upheld in district court and the decision has been appealed by industry, It is possible that the regulations will be revised as a result of this litigation. Legislative modifications to sulfur reduction standards are also in early stages of consideration by Congress. Revisions that would allow a more flexible sliding scale for sulfur reduction would lessen the adverse impact of the 1979 NSPS on the competitive position of Western coal in Midwestern markets, but not eliminate it. For example, the Mining Task Force of the National Coal Policy Project concluded before the 1979 NSPS were promulgated that the Clean Air *Act* Amendments of 1977 (which require utilities to install the best available control technology on all new plants) would mean that coal production in the Northern Great Plains was not likely to increase as much as would happen under the 1970 NSPS. F. X. Murray (cd.), Where We Agree: Report of the National Coal Policy Project V.2 (Boulder, Colo,: Westview Press, 1978).

[6]A. W. Deurbrouck, Sulfur Reduction Potential of Coals in the United States, Bureau of Mines RI 7633 (Washington, D. C.: U.S. Government Printing Office, 1972).

(rather than 90 percent) for Eastern coal compared to 70 percent for low-sulfur Western coal. Coal cleaning is not generally practiced on Western coal primarily because of the generally low heat content of these coals that are used by utilities, and because Western coals tend to be high in organic sulfur, which is not amenable to reduction by conventional mechanical cleaning processes.

The 1979 NSPS for SO_2 have not been in effect long enough to allow full evaluation of their effect on coal markets, but it appears that stack gas scrubbing costs for high-sulfur coal (with credits for sulfur reduction by cleaning before combustion) and for low-sulfur Western coal will not differ greatly. If this proves to be the case, it would largely eliminate sulfur content in coal as a key factor in coal purchasing decisions for new powerplants by electric utilities, although there are some situations where Western coal may retain a competitive advantage based on sulfur content. For example, in nonattainment areas where further development hinges on reducing total emission of SO_2, low-sulfur coal may have an advantage because full (i.e., 90 percent) stack gas scrubbing of low-sulfur coal emits less total SO_2 than the same amount of scrubbing of high-sulfur coal.

In summary, the competitive position of Western coal varies according to the kind of limitations that are set on the emission of SO_2. At one extreme, the absence of restrictions on SO_2 emissions would make the delivered price, rather than the sulfur content of the coal, the key factor in purchasing decisions. The 1979 NSPS will probably achieve a similar result. In contrast, the 1970 NSPS gave low-sulfur Western coal a significant competitive edge, and strict limitations on the total level of emissions also favor Western coal.

The full effect of the 1979 NSPS (if they are not modified) will not be felt until the late 1980's because a large percentage of new coal-fired capacity that will come online between 1980 and 1985 was ordered before the NSPS went into effect.[7] The major impacts of the 1979 NSPS in the next decade will be in the effect it has on determining which coal regions will supply those new coal-fired plants that will be built in the late 1980's and that have not signed long-term contracts for coal.[8]

Mine Costs

Now that sulfur content will probably be a less significant factor in the marketing of Western coal, the single most important competitive advantage retained by Western coal is its low cost at the mine mouth. Table 28 summarizes recent representative steam coal contract prices in January and June 1981 for the major Federal coal-producing States and ranges of prices within the Midwestern and Appalachian coal regions. In January 1981, typical price per ton from the Powder River basin in Wyoming and Montana ranged from $6.75 to $12.00/ton, and in the other Western coal States, for higher Btu coal, from $16.00 to $20.75/ton. In contrast, prices for Midwestern coal range from a low of $17.00 to $27.501 ton and for Appalachian coal from $23.00 to $34.50/ton. The actual cost spread is a little less when these prices are translated into cost per million Btu. For example the low price for coal in the Midwest of

‘Eighty-three percent (49,200 of the projected 59,400 gigawatts total net capacity) of new coal plants that are planned to come on line between 1979 and 1985 will be constructed to meet the 1970 NSPS rather than the 1979 NSPS, and an additional 5,800 gigawatts planned to come on line between 1985 and 1990 will be under the old standards because orders for boilers were made before the new standards took effect (numbers calculated from tables 3-7 and 3-9, app. A, Forecasts and Sensitivity Analysis of Western Coal Production, Washington, D. C.: ICF, Inc., November 1980).

[8]It should be noted that the present administration has proposed that the mandatory scrubbing requirements in the 1977 Clean Air Act Amendments be eliminated. However, if the 1979 NSPS are repealed, it is not certain that low-sulfur Western coal would be as attractive to Midwestern utilities as it was in the 1970's. For example, a study by Data Resources Inc. (DRI) has concluded that eastern and Midwestern electric utilities would continue to favor local high-sulfur coal, even if the mandatory scrubbing requirements were dropped (*Coal Week*, May 18, 1981). The reason for this is that DRI's projections of rail rate increases for Western coal offset the cost savings from not having to control the SO_2 emissions.

Table 28.—Representative Mine-Mouth Prices and Transportation Costs for Western Coal (January and June 1981)

	Contract steam coal price (FOB)			Representative rail rates ($/ton)					
State	Btu/lb	$/ton	$/mm Btu	From To:	Minneapolis	Omaha	Kansas City	Chicago	Hammond, IN
Montana	8,600	9.75	0.57	Colstrip MT	11 .46[a] 21.44[b] (22.31)			—	
	9,300	12.00	0.65	Decker MT	—		—	18.69[a] (18.26)	18.94[a] (18.00)
Wyoming. . . .	8,100’	6.75 (7.00)	0.42 (0.43)	—	—			—	—
	1 0,500*	16.50	0.79	Hanna WY	—	10.89[a] (11.04)	8.0118.97[a] (9.1 1/10.13)	12.43a (14.30)	14.24[a] (16.29)
Colorado	10,700	17.50 (19.00)	0.82 (0.89)	Routt CO	—	19.65[b] (20.63)		·	—
	11,600	20.75 (22.00)	0.88 (0.95)	—	—		—	—	—
Utah.	11,500	20.50	0.89	Utah	30.25[b] (31.76)				—
New Mexico .	10,000	16.00	0.80						
Midwest	9,500 to 12,000	17.00 to 27.50 (29.00)	0.73 to 1.18 (1.26)						
Appalachia. .	11,200 to 13,000	23.00 to 34.50 (37.00)	0.83 to 1.43						

[a]Unit train rate
[b]Single car rate
[c]Powder River Basin
[d]Southern Wyoming

NOTE Number in parentheses Indicates price change from January to June 1981 No parentheses Indicates no change

SOURCE *Coal Week.* Jan 5, 1981, and June 8, 1981

$17.00/ton is 2.5 times higher than the low price for Western coal, but on a Btu basis the spread is reduced to a factor of 1.7. The low cost of mining Western coal can be attributed primarily to low production, labor and reclamation costs for both surface and underground mines with coal seams that are thicker than those in the Midwest and Appalachia.

Transportation Costs

Western coalfields are located far from the main centers of coal demand in the Midwest and South-Central United States. Consequently, transportation costs are one of the major market disadvantages experienced by Western coal and are probably the single largest overall factor in market decisions concerning Western coal. Table 28 shows some representative rail rates from points in the West to the Midwest, In all the examples shown here, except from Hanna, Wyo., the rail transport costs exceed the mine-mouth cost. The cost advantage of unit train rates is also clearly shown in this table. From Colstrip, Mont., to Minneapolis, Minn., single car rates are almost twice unit train rates. The difference works to the disadvantage of Colorado and Utah where single mines often cannot produce enough to justify commitment of unit trains. Table 28 also shows that rail rates are changing at a faster rate than mine costs in the West. During the first 6 months of 1981 all except one rail rate changed, and most of the changes involved increases of $1.00/ton or more. In contrast, most coal prices in the West remained unchanged during this same period.

There is a general consensus that rail transportation costs over the next 10 years are likely to increase at a faster rate than in-

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flation.[9] Coal slurry pipelines may reduce transportation costs between certain points, but there is no consensus as to how significant these cost savings may be, nor is there much certainty as to the magnitude of real increases that can be expected in rail transport costs (see ch. 8).[10] However, the net effect of real increases in transportation costs will adversely affect the competitive position of Western coal with respect to Midwestern coal because longer distances are involved.

The alternative to shipping coal to centers of demand is to generate electricity at the mine mouth and ship the energy by wire. North Dakota, which is relatively close to centers of electricity demand in 'the upper Midwest, and New Mexico, which is relatively close to centers of demand for electricity in southern California both export significant amounts of electricity by wire. However, several factors tend to limit the level of mine-mouth generation to primarily what is needed within the Western Federal coal-producing States and adjacent States: 1) long-distance transmission of electricity is generally expensive because of high capital costs, 2) the availability of water is less (although use of dry-cooling towers can reduce some of the problems related to water availability), and 3) the relative environmental and social impacts of large-scale powerplants are greater in the arid and semiarid West compared to the Midwest and South-Central United States.[11] Transportation by wire is discussed in more detail in chapter 8.

Reclamation Costs

Reclamation requirements under the Surface Mining Control and Reclamation Act of 1977 give Western coal a decided competitive advantage compared to Eastern coal because the relative cost increases attributable to the Act are small in the West compared to the Midwest and Appalachia. Typical incremental costs with Public Law 95-87 have recently been estimated to be $5.24/ton in Appalachia, $1.80/ton in the Midwest and $0.57 ton i n the West.[12] The incremental cost differential because of reclamation requirements between Western and Midwestern coal (a factor of 3) is more significant than the cost differential between Appalachian and Western coal (a factor of 10) because Western and Appalachian coal serve different market areas, whereas the market areas for Midwestern and Western coal overlap. Less stringent reclamation requirements for mining would probably have the effect of improving the competitive position of Midwestern coal with respect to Western coal because cost reductions from less stringent reclamation standards would generally be greater in the Midwest.

Royalty Rates and Severance Taxes

Royalty rates on coal produced in Western States were generally very low before the 1970's reflecting the relatively low value attributed to Western coal reserves. The increased demand for coal in the West in the 1970's resulted in increases in royalty rates

[9] Participants in a conference held in Cctober 1980, shortly after the Staggers Rail Act of 1980 was signed into law reached the general conclusion that there would be an almost immediate impact in terms of increased rates for shipping coal (Coal Week, Oct. 20, 1980). The Department of Energy assumed a 15-percent real increase in rail transportation costs between 1978 and 1985 in setting its preliminary regional coal production goals. However, ICF has found that between 1978 and 1980 alone real increases (i. e., adjusted to account for inflation) were 10.5 percent, almost as much as DOE's projected increase over the 7-year period. This underestimation of likely rail increases resulted in a considerable overestimation of demand for coal from the Powder River basin (ICF, Inc., Analysis and Critique of the Department of Energy's August 7, 1980 *Report* Entitled "Preliminary *National and Regional Coal* Production *Goals for 1985*, 1990 and *1995*" (Washington, D. C.: ICF, Inc., October 1980).] In the final production goals, DOE increased assumed escalation of transportation costs to 25 percent. Rocky Mountain Energy Co. projects a 40-percent real increase in rail transportation costs in southern Wyoming between 1980 and 1990 (personal communication, Stephen Berg-Hansen, Wyoming Task Force, Oct. 16, 1980).

[10] See also Office of Technology Assessment, U.S. Congress, Coal *Slurry* Pipelines, *Summary* (Washington, D. C,: U.S. Government Printing Office, September 1980), p. 8, This summary updates an earlier report, A *Technology* Assessment *of Coal Slurry* Pipelines (Washington, D. C.: U.S. Government Printing Office, March 1978),

[11] See for example discussion on pp. 199-201 in F. X. Murray (cd.), Where We *Agree*: Report *of the National* Coal *Policy* Project *V.2* (Boulder, Colo.: Westview Press, 1978).

[12] National Research Council, *Surface* Mining *Soil, Coal and Society* (Washington, D. C,: Academy Press. 1981). This study's analysis of reclamation costs is discussed in more detail in ch. 10.

as coal was perceived by both the owners and potential lessees as having a higher value. Indian tribes and private leaseholders led the way in exacting higher royalty rates in the early 1970's. The 1976 Federal Coal Leasing Amendments Act (FCLAA) set minimum production royalty rates on surface coal at 12½ percent; a lower royalty rate (currently 8 percent) is permitted for underground coal. Several States followed suit in raising royalty rates, and new leasing transactions of non-Federal coal generally follow minimum levels set by the Federal Government.

The overall effect of changing royalty rates has been to create considerable differentials in royalties between "old" 'and "new" leased coal. Federal leases before 1976 contained nominal royalties by today's standards. The average royalty rate on Federal coal mined in 1977 was 18.8 centslton. Royalty rates at current contract prices at rates set in FCLAA may be more than 10 times that. The Department of the Interior (DOI) is required to raise royalty rates when leases come up for adjustment, consequently over the next 10 to 15 years as leases are adjusted, there will exist a dual royalty standard that could affect the competitive position of individual Federal leases with respect to other Federal leases and non-Federal coal. Without a systematic analysis of the intraregional and interregional effects of differential royalty rates, it is difficult to draw conclusions concerning the impact of these differentials on coal markets.

Severance taxes* imposed by States also add to the mine-mouth cost of coal. In the Western States severance taxes range from zero in Utah to 30 percent in Montana. A comparison of severance taxes on surface mined coal in the West shows that cost per million Btu is roughly the same in Colorado, New Mexico, North Dakota, and Wyoming (generally 3 to 5 cents/million Btu).[13] Severance tax costs in Montana run three to four times higher. Severance taxes and royalty rates add to the cost of coal, but increases attributable to these sources are relatively small compared to the cost of mining and transporting the coal. Consequently, such difference may cause shifts in the location of the coal production between Western States (as could be the case in Montana,)* or from Western coalfields to other coalfields, but do not have a significant impact on the availability or overall demand for coal.

Industrial Demand

Utah, Colorado, and New Mexico are the only Western States with significant reserves of metallurgical coal. In 1979 these three States supplied only 3 percent of the metallurgical coal that was used by the steel industry although they supplied nearly all of the metallurgical coal used in the West. The rest was produced and mostly consumed in the Midwest and Appalachia. Federal leases in Oklahoma also contain metallurgical coal, and demand for Federal coal from this State hinges strongly on the needs of the steel industry. Even a dramatic increase in the demand for metallurgical coal would not have much effect on the total demand for Western coal, given its small share of that market.

Industrial coal burning in California presents a significant source of potential increased demand for coal from Utah, southern Wyoming, New Mexico, and Colorado, but little realization of this potential is expected within the next 10 years because of the economic costs of converting boilers from natural gas or oil to coal, combined with the costs of emission controls. The same is probably generally true of industrial boiler conversion in the Midwest and South-Central United States where Western coal also experiences competition from Gulf Coast lignites and Midwestern coal production. Significant increases in demand for coal be-

*See ch. 12 of this report for a description of State coal severance taxes.

[13] Colorado Energy Research Institute, Mineral Severance Taxes in the Western States: A Comparison (Golden, Colo.: CERI, 1979).

*The impact of the Montana severance lax is discussed in more detail in the section on market advantages and disadvantages of Montana coal later in this chapter.

cause of industrial boiler conversions are not likely to be experienced until after 1990.[14]

In 1979, 6 percent of total coal production in the far Western States (including Arizona and Washington) was for nonmetallurgical industrial uses, most of which was used for lime and cement kilns, metals processing, and sugar processing (table 22, ch. 4). Some increase in demand for coal for such industrial uses may occur, but dramatic increases are not likely, thus the major potential source of increased industrial demand for coal will be industrial boiler conversions.

Synthetic Fuels

A major disadvantage of coal is that it is not as convenient to use and transport as oil and gas, and is not directly substitutable for use in the transportation sector, which accounted for 25 percent of the total energy use in the United States in 1979. Synthetic gas and liquids can be produced from coal, but at a high cost. Relative costs of oil and gas and coal-based synthetic fuels are still such that synthetic fuels cannot currently compete in the market place, although some large energy companies may be willing to commit funds to commercialization of coal-based synthetic fuels in anticipation of future oil and gas price rises. Nevertheless, demand for coal to produce synthetic fuels during the next decade is likely to depend to a large extent on Government incentives. Coal-derived liquids must also compete with oil shale, which produces a synthetic crude oil that can be processed in conventional refineries. At present the uncertainties in the cost estimates for the various synthetic liquid fuels are larger than the estimated difference in the cost of coal and oil shale derived synthetic liquids.

NCA's long-term forecast for coal production concludes that coal synfuels production will fall short of production goals set by the Federal Government when it created the Synthetic Fuels Corp. NCA estimates that coal synfuels production is not likely to exceed **200,000** barrels per day (bbl/d) of oil equivalent by 1990 in contrast to the goals of 500,000 bbl/d in 1987 and 2 million bbl/d in 1992 established by the Government (of which two-thirds was to have come from coal).[15] NCA stated that the goals were unrealistic considering the economic, technical, environmental, and other regulatory conditions in which synfuels plants must be built.

The current status of coal-based synfuels projects indicates that most of the demand for coal for this purpose during the next decade is likely to be in the Midwest and East rather than the West. A survey by NCA of existing and proposed coal-based synfuel facilities found that the largest coal synfuel facilities operating in the United States are pilot plants in Kentucky and Texas, and that the only large commercial synfuel plant under construction in 1980 was located in Tennessee.[16] According to this survey, of the four large-scale synfuels demonstration plants that were expected to start construction in 1981, only one, the Great Plains Gasification Associates' project in North Dakota, was located in the West. The other three are located in Kentucky, West Virginia, and Illinois.

On the other hand, DOE assumed in its final 1980 coal production goals that 60 percent of the 1990 demand for coal feedstock for synfuels will be west of the Mississippi, most of which (45 percent of total demand) would be from the six major Western Federal coal States.[17] This assumption was based on two major considerations: 1) the technical superiority of low caking Western coal when used with first-generation conversion technology and 2) the relative abundance of low-cost strippable Western coal resources. However, the assumed l-million-bbl/d total U.S. production of coal-based synfuels (20 plants with a capacity of 50,000 bbl/d oil equivalent

[14] F. Hachman, Market Factors Associated With the Assessment of the Development Potential of Federal *Coal* Leases in Utah, prepared for OTA, 1980.

[15] NCA, NCA Long-Term Forecast, op. cit.

[16] National Coal Association. Survey of Existing and Proposed Synthetic Fuel Facilities (Washington, D. C.: NCA, September 1980).

[17] U.S. Department of Energy, The Biennial *Update of National* und *Regional Coal* Production *Goals* for *1985, 1990* and *1995* (Washington, D.C.: DOE, January 1981).

nationwide) exceed other estimates of likely levels of synfuel production by 1990.

Evaluation of this potential for coal-based synfuel development in the West by OTA in the different State assessments generally agrees with the data in the NCA survey, indicating limited development of Western coal to support synfuels plants before 1990, The OTA Wyoming task force judged only one of the three Federal lease blocks in Wyoming that are associated with synthetic fuels projects to have favorable production prospects by 1991 and recent developments have increased the uncertainty that this project will be online by then.[18] The market analyses prepared for the Utah and Colorado task forces concluded that the use of coal for synfuels in those States would be minimal by 1991.[19] The New Mexico task force projections assumed that no commercial-scale synthetic fuel plants using New Mexico coal would be in operation by 1990.[20]

All of the barriers to beginning full-scale construction of the most advanced commercial-scale Western synfuel project in the NCA survey have been overcome. Preconstruction activities began on the Great Plains Gasification Associates' coal gasification facility in Mercer County, N. Dak,, in August 1980. The first unit of the plant, which would use 4.7 million tons per year of lignite, is scheduled to be in operation in late 1984. The project had considerable difficulty in developing a financing plan that was acceptable to the Federal Energy Regulatory Commission and consumers who would purchase the gas. The original financing plan was revised in January 1981, and received approval in May. Citing possible cost overruns and the need for a separate pipeline, the project sponsors increased their loan guarantee request to DOE from $1.8 billion to $2.0 billion. This request was approved by President Reagan in early August 1981.

A study prepared for OTA by the Colorado School of Mines Research Institute on the synfuels potential of Western coal concluded that significant commercial production of high-Btu gas from coal is unlikely for at least 10 years even with Federal incentives.[21] Development activities related to medium- and low-Btu gasification facilities are strongly dependent on the availability of natural gas. The Institute's study concluded that the relative abundance of natural gas, and the prospects for acquiring additional supplies from new foreign and domestic sources have dampened the development of small-scale industrial gasifiers.

This study also concluded that significant commercial production of coal liquids is unlikely over the next 10 years. Even if substantial Government incentives are offered, commercial production levels are expected to be less than 100,000 to 200,000 bbl/d of synthetic liquid, primarily because of the leadtimes for construction and the risks associated with first generation plants. Because of these risks, industry is likely to wait until processes have been demonstrated on a com-

[18] J. R. Boulding and D. L. Pederson, Development and Production Potential of Undevelopcd Federal Coal Leases and Preference Right Lease Applications in the Powder River Basin and other Wyoming Coal Basins, final report (Washington, D. C.: OTA, 1981). The one block with favorable prospects is the Rochhelle lease held by Peabody Coal Co., which is committed to Panhandle Eastern's proposed gasification plant near Douglas. Wyo. This gasification project received a major setback in August 1981 when Pacific Gas & Electric and Ruhrgas Aktiengesellschaft of West Germany announced they were withdrawing from their preliminary partnership agreement for the project. Consequently, it is uncertain whether any synfuel plants will be producing in the Powder River basin by 1991. The other two blocks associated with synfuel proposals are Texaco's Lake DeSmet block in the western Powder River basin and Nerco's Cherokee block in southern Wyoming. These were judged by the Wyoming task force to have uncertain production prospects by 1991. Subsequent analysis by OTA changed 1991 production prospects for the DeSmet block from uncertain to unfavorable. Two other proposed synfuel projects in Wyoming are still in the early stages of development. The Hampshire project proposed for the eastern Powder River basin is not associated with a specific source of coal, and a coal to gasoline plant proposed by Mobil would involve entirely non-Federal coal in the western Powder River basin.

[19] See Hachman, op. cit.: and J. E. Martin, Market Factors and Production Contingencies Determining the Present and Future Demand for Colorado Coal (Lakewood, Colo.: Colorado Energy Research Institute, December 1980).

[20] The Development Prospects for Federal Coal Leases in New Mexico, 1980-1990 (Washington, D. C.: OTA, November 1980].

[21] Colorado School of Mines Research Institute. Synfuels Potential of Western Coal, Draft Report, prepared for OTA, Oct. 31.1980.

mercial scale before committing to build a large synfuels industry. Because commercial demonstration is not possible until the late 1980's, 1990 production levels are likely to be limited to the capacity of the first generation pioneer plants.

Foreign Export

Japan, Korea, and Taiwan are expecting to significantly increase their imports of coal during the next 10 years, and have purchased coal from several Western States for test burns. Initial shipments of coal have been made to Japan from Utah and to Korea from Colorado. Current capacity of port facilities to handle coal for foreign export on the west coast is about 3 million tons, and significant export of Western coal will require considerable expansion of existing facilities and construction of new facilities to handle coal. NCA estimates that countries in the Far East will import from 153 million to 180 million tons in 1990.[22]

Potential competitors to the United States for the coal demand in the Far East are Australia, Canada, China, the Soviet Union, and South Africa. The NCA range of projected coal exports for these countries in 1990 is 195 million to 240 million tons, which is well above the range of import demand in the Far East (although all export from these countries is unlikely to go to the Far East). Consequently, the Western coal States will be entering a competitive market; it is thus difficult to predict what share of this market the United States is likely to obtain. Australia has a considerable competitive advantage over coal produced in the Western United States, but the Japanese in particular appear to be placing limited coal commitments elsewhere as a hedge to limit the strength of the Australian position.[23]

The Japanese have expressed the greatest interest in high-Btu bituminous coal with low ash, moisture, and sulfur content, which gives the Rocky Mountain coal region a probable advantage over the Northern Great Plains. The recent expressions of interest by the Japanese in Powder River basin coal have resulted in plans to construct a coal export facility at Kalama, Wash., that could have an export capacity of 15 million tons by 1983. Export of subbituminous coals from the Powder River basin will probably depend on the development of slurry pipelines and technology for drying the coal to upgrade its heat content. A recent analysis of the economics of export from the west coast did not consider Powder River coal to have significant export potential in the near future, primarily because of its lower heat content.[24] The potential for export of Alaskan coal to the Pacific Rim countries was not examined in this study.

If the Japanese would make firm commitments to purchase significant amounts of Western coal, port facilities could probably be constructed to meet the demand for export. However, such firm commitments have not yet been made, and existing ports that handle coal on the west coast are reluctant to expand or construct new facilities until higher volumes of coal are assured. In the absence of firm commitment by Asian countries to purchase Western coal, it is very difficult to predict the level of foreign exports of Western coal by 1990, ICF projects exports from the west coast to be 2 million tons in 1985 and 14 million tons in 1990.[25] The Interagency Coal Export Task Force projects an upper limit of 15 million tons in 1990 for west coast export.[26] DOE final production goals assume that 12 million to 35 million tons of coal in 1990 will be exported from west coast ports.[27]

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[22] NCA, NCA Long-Term Forecast, op. cit.

[23] Hachman, op. cit., pp. 24-25.

NOTE: See also, Office of Technology Assessment, U.S. Congress, Coal *Export* and Port Development (Washington, D. C,: U.S. Government Printing Office, April 1981),

[24] G. B. McMeans, Jr., The Economic Viability of Proposed West Coast Coal Port Sites (Oakland, Calif.: Kaiser Engineers, Inc., 1981). This paper presented at Coal Outlook's Conference, Charting the Course of Western Coal, June 8-9, 1981 says "we are not optimistic about the export potential of Powder River Basin subbituminous coals. "

[25] Table 4-2, app. A, ICF report cited in footnote 4.

[26] Interagency Coal Export Task Force, Interim Report, DOE/FE-0012 (Washington, D.C.: U.S. Department of Energy, January 1981).

[27] Tables 35, 36, and 37 in DOE report cited in footnote 17.

Institutional Constraints

Later chapters on transportation, environmental, and socioeconomic issues examine in more detail the impacts of various institutional constraints on coal production in the West. There are some specific instances where Federal coal reserves under existing lease cannot be mined because of environmental restrictions, but the total reserves involved in such restrictions are relatively small. * It does not appear that implementation of environmental policies are likely to pose a significant constraint on the ability of Western States to produce coal. Infrastructure constraints, such as the ability of communities to expand services to accommodate population increase because of coal development and the ability of transportation systems to deliver coal to the areas of demand may cause constraints on a site-specific basis. However, such constraints do not appear likely to prevent Western coal States from meeting the possible ranges of demands that are likely during the next 10 years. (See ch. 6 for estimates of production from the Western Federal coal States.)

*See ch. 10, espercially table 93 on p. 317.

Factors Affecting Competition Between Western Coal States

The net result of the various factors and trends discussed in the previous section is that conditions favoring rapid increases in demand for coal from the major Federal coal States are not as favorable for the 1980's as they were in the 1970's, This does not mean that there will not be substantial increases in Western coal production—the low cost of mining Western coal will ensure that—but it does mean that the West's share of coal markets will probably not be as great as has been commonly anticipated. The major reasons for this are: 1) reduction in the low sulfur advantage, 2) lower electrical growth rates. and 3) higher transportation costs. Offsetting these trends somewhat is the likelihood that the South-Central United States, which is a major consumer of Western coal, will have a high growth rate in coal-fired powerplants to replace gas-fired plants. Nearly 60 percent (174 million of 301 million tons) of NERC'S projected new annual demand for utility coal and lignite from the West between 1979 and 1989 will be consumed in the South-Central region (ERCOT and SPP regions). Consequently, the overall demand for Western coal will be highly sensitive to both electrical growth rates and gas to coal conversions in this region. It is more difficult to evaluate the factors affecting demand for coal in the 1990-2000 time period, but some discussion of this can be found later in the Demand for Western Coal; 1990-2000 section.

This section looks in more detail at the relative market advantages and disadvantages that coal producers in each of the major Federal coal-producing States experience with respect to demand for coal in the West and in other parts of the United States. These relative advantages and disadvantages are summarized in table 29. The next section examines the net effect of these advantages and disadvantages in the share of total production and geographic market areas of the different States.

North Dakota

In 1979 North Dakota produced 15.0 million tons of lignite, ranking fifth out of the six major Federal coal States. The key market disadvantage of North Dakota lignite is its low heat content and poor handling characteristics for long-distance transport. Lignite tends to combust spontaneously when exposed to air, and is difficult to unload from rail cars in winter because moisture in the

Table 29.—Major Market Advantages and Disadvantages of the Major Federal Coal-Producing States

Major market advantages	Major market disadvantages
North Dakota	
—Large amounts of surface reserves with easy mining conditions. —Low mine-mouth cost. —Availability of water for onsite development.	—Low heat content and tendency of lignite to spontaneously combust when exposed to air restricts markets almost entirely to mine-mouth development. —PSD air quality limitations may restrict the level of mine-mouth development that is possible.
Montanta	
—Large amounts of surface minable reserves allow high-volume long-term contracts. —Low mine-mouth cost. —Relatively low sulfur content. —Higher heat content compared to the Wyoming Powder River basin,	—Long distance from major coal demand centers in Midwest and South-Central United States means transportation costs are a high percentage of delivered cost. —High severance tax (30%). —Low heat content compared to Rocky Mountain coal States,
Wyoming *Powder River basin*	
—Large amounts of surface minable reserves allow high-volume, long-term contracts. —Very thick coal seams, low strip ratios mean low mine. mouth costs. —Low sulfur content.	—Low heat content compared to Montana and Rocky Mountain States. —Long distance to major coal demand centers in the Midwest and South-Central United States means transportation costs are a high percentage of delivered cost. —Availability of water for onsite development IS limited. —Some current and potential future problems with rail capacity for out-of-State markets.
Southern Wyoming	
—Relatively high heat content. —Moderately extensive reserves of thick multiple seams that can be surface mined. —Central geographic location facilities competition in all Western States except the Southwest. —Reserves well located with respect to existing rail lines.	–Difficult mining conditions (commonly caused by dipping coal beds) increase cost of both surface and underground mines. —Long distance from major coal demand centers in the Midwest and South-Central United States means transportation costs are a high percentage of delivered cost.
Colorado	
—Most reserves are high Btu and low sulfur. —Significant reserves of metallurgical grade coal. —Central geographic position allows marketing in all Western States.	—Majority of reserves must be underground mined, resulting in relatively high mine-mouth costs. —More distant from demand centers in the west coast than Utah and New Mexico. –Transportation costs to demand centers in the Midwest and South-Central United States are higher compared to Montana and Wyoming because most production must cross high mountains and rail routes are not as direct and require more carriers.
Utah	
—High-quality reserves (high Btu and low sulfur), —Significant reserves of metallurgical coal. —No severance tax. —Relatively close to coal demand centers on west coast,	–Most production is from underground mines resulting in high mine-mouth costs. —Southern Utah fields distant from transportation networks. —Very far from major demand centers in the Midwest and South-Central United States. —Some reserves in southern Utah are near National Parks.
New Mexico	
—Large reserves of medium-Btu (9,500-10,500 Btu/lb) low-sulfur coal allows high-volume, long-term contracts with utilities. —High-Btu metallurgical grade coal in Raton Mesa region. —Closer to coal demand centers in Texas than other Northern Plains or Rocky Mountain States.	—Some reserves are not generally well served by transportation networks. —Some coal in Raton Mesa region must be underground mined with higher mining costs. —High ash content of some coals sometimes requires coal cleaning, thus increasing cost.

SOURCE Off Ice of Technology Assessment

lignite freezes. The low heat content limits coal sales almost entirely to nearby powerplants (or synfuel facilities) in the State with some export to the adjacent States of South Dakota and Minnesota. Air quality thresholds, as mentioned previously, are becoming a factor to consider in the use of North Dakota lignite reserves in mine-mouth power and synfuel plants.

The key market advantages of North Dakota lignite are that water is readily available for onsite development and there are large reserves of surface minable lignite that can be mined at a relatively low cost, North Dakota is also located closer to the electricity demand centers in the upper Midwest than other Western States, and reserves are well--suited for commercially available gasification technologies.

Montana

In 1979 Montana produced 32.5 million tons of coal, ranking second among the six major Federal coal States. The major market advantages in Montana are large reserves of surface minable coal, with generally higher heat content compared to other Northern Plains States (but relatively low compared to the Rocky Mountain States). Four counties in the Montana portion of the Powder River basin contain an estimated 32 billion tons of strippable reserves,[28] Mine-mouth costs are generally half that in the Midwest (see table 28) but transportation costs are high, comprising about one-half to two-thirds the delivered cost in the Midwest. The Crow and Northern Cheyenne Tribes have large reserves of coal that do not depend on Federal, State, or private coal to form minable blocks,

Montana has the highest severance tax in the United States, Between 1970 and 1975 (the year Montana's severance tax was instituted) growth rates in coal production in Montana and Wyoming were approximately the same. Between 1976 and 1979 the growth rate in coal production in Wyoming was almost three times that of Montana (19.3 percent compared to 6.5). Several published reports have concluded that Montana's severance tax has depressed the growth rate of coal production in the State and point to the difference in growth rate between Montana and Wyoming as evidence.[29] However the difference in growth rates between the two States can also be attributed to other factors than the severance tax, such as limits on the availability of rail lines to areas for proposed new development, and slightly higher production costs before severance taxes are applied in either State. It is possible that Montana's higher severance tax may increase Wyoming's share of production from the Powder River basin compared to what it would have been without differentials in severance taxes, but no analysis of Montana's severance tax to date has established a clear relationship between the tax and changes in Montana coal production,[30] Whatever its relative impact in Montana and Wyoming, the severance tax remains a small percentage of the delivered price of electricity generated from Powder River basin coal, and despite the high severance tax planned production capacity in Montana during the next 10 years is high (see chs. 6 and 7).

Wyoming

In 1979 Wyoming produced 71,8 million tons of coal, which was 44 percent of total coal production from the six major Federal coal States and more than twice the production from Montana, which was the second ranked State of the six. This high level of production is the result of favorable conditions in the State's coalfields in both the Powder River basin and southern Wyoming. Wyoming has very large (23 billion tons) reserves of surface minable coal in thick coal seams with low stripping ratios in the Powder River

[28] 13R, E.Matson and J. W. Blumer, *Quality and Reserves of Strippable Coal Selected Deposits, Southeastern Montana*, bulletin 91 (Butte, Mont.: Montana Bureau of Mines and Geology, December 1973).

[29] See for example Coal Age, April 1979, p. 39, and House Committee on Interstate and Foreign Commerce, *Coal Severance Taxes*, hearing report 96-173 (Washington. D. C.: U.S. Government Printing Office, 1980).

[30] Personal communication, Arnold Silverman, professor of Economic Geology a t the University of Montana, Missoula (phone conversation, Feb. 10, 1981].

basin, and also moderate reserves (3.2 billion tons) of medium-Btu coal (9,500 to 10,500 Btu/lb) in southern Wyoming that can be surface mined.[31]

Coal in the Powder River basin of Wyoming is cheaper to mine than anywhere else in the United States. The best coal deposits in the Powder River basin are also well located with respect to rail lines, and are likely to be served by at least one coal slurry pipeline by the mid or late 1980's. The major disadvantage of coal from the Powder River basin is that it has a low heat content, and there are some potential bottlenecks outside of Wyoming in transporting coal by rail to markets to the East and South. Reserves are sufficient to support many mine-mouth conversion facilities, but the availability of water for onsite development, plus other siting problems limits the likelihood of extensive onsite development during the next 10 years.

The central geographic position of coalfields in southern Wyoming, combined with their close location to the Union Pacific Railroad's main line, facilitates competition in States to the East and West. Mining conditions are generally more difficult in southern Wyoming compared to the northern Great Plains both because dipping coal seams are more difficult to mine and also because the more arid climate creates more difficult conditions for reclaiming mined land. As a consequence, mine-mouth prices are higher, even when the higher heat content is taken into account.

Colorado

In 1979 Colorado produced 18.1 million tons of coal, ranking third among the six major Federal coal States. The main advantage of Colorado coal is high heat content and low-sulfur content, reserves of surface and underground coal that are served by existing transporatation networks, significant reserves of metallurgical coal, and a central geographic position that allows marketing in the Southwest as well as the Midwest and west coast.

One of the major market disadvantages is that the majority of reserves in the State must be underground mined, resulting in relatively high mine-mouth costs. However, surface mine production will continue to provide at least half of Colorado's coal output through the 1980's. Transportation costs place Colorado somewhat at a disadvantage in both Western and Midwestern market areas compared to the other States. Utah is closer to west coast demand centers, and New Mexico is closer to both major demand centers in southern California and in the South-Central United States. Even though Colorado is closer to the demand centers in the South-Central United States than Montana and Wyoming, transportation costs are relatively higher because most production must cross high mountain passes and rail routes are not as direct. The mountain passes increase transportation costs because steep grades necessitate more engines and fewer cars than typical unit trains. Also, lines owned by two or three railroads must be traversed to reach most destinations in the Midwest and South-Central United States. Because of these transportation costs, a significant fraction of the coal used by utilities in eastern Colorado comes from Wyoming.

Utah

In 1979 Utah's coal production was 11.8 million tons. The main advantage of Utah coal is high heat content of steam coal, reserves of metallurgical coal, and close location to demand centers on the west coast, The major disadvantages are that virtually all present production is from underground mines, and consequently mine-mouth costs on the average are the highest of any Western State. Fields in southern Utah have significant surface minable reserves, but are distant from existing transportation networks. Twenty-four million tons of the Alton field reserves in southern Utah nearest to Bryce Canyon National Park have been designated by DOI as unsuitable for mining, Utah is also very far from coal demand centers in the Midwest and

[31]Reserve data from table 9, G. B. Glass, Wyoming *Coal Fields, 1978*, inf. cir. No. 9 (Laramie, Wyo.: Geological Survey of Wyoming, 1978).

South-Central United States with consequent high transportation costs, Nevertheless, Utah coal, because of its high heat content and low sulfur content has penetrated these markets (see fig. 20).

New Mexico

In 1979 New Mexico produced 15.1 million tons of coal, slightly more than fifth-ranked North Dakota. The major market advantages of coal in New Mexico are the presence of moderate reserves of medium-Btu (9,500 to 10,500 Btu/lb) surface minable coal in the San Juan River region, sufficient to supply high-volume, long-term contracts with utilities. The Raton Mesa coal region has high-Btu coal, but a substantial fraction must be underground mined and thus has a relatively high mine-mouth cost per ton. New Mexico is closer to coal demand centers in Texas than other Western coal-producing States and this represents a significant potential market that has as yet been unrealized because some of the existing coal leases are not well served by transportation networks. Extensive development of coalfields in the San Juan basin depends on construction of the Star Lake-Bisti Railroad. A significant disadvantage of some New Mexico coal is that some of the major coal deposits in the San Juan River region are quite uniformly high in ash content (generally greater than 14 percent) and cleaning to reduce ash adds to the cost of using the coal.

The Market Area of Western Coal States

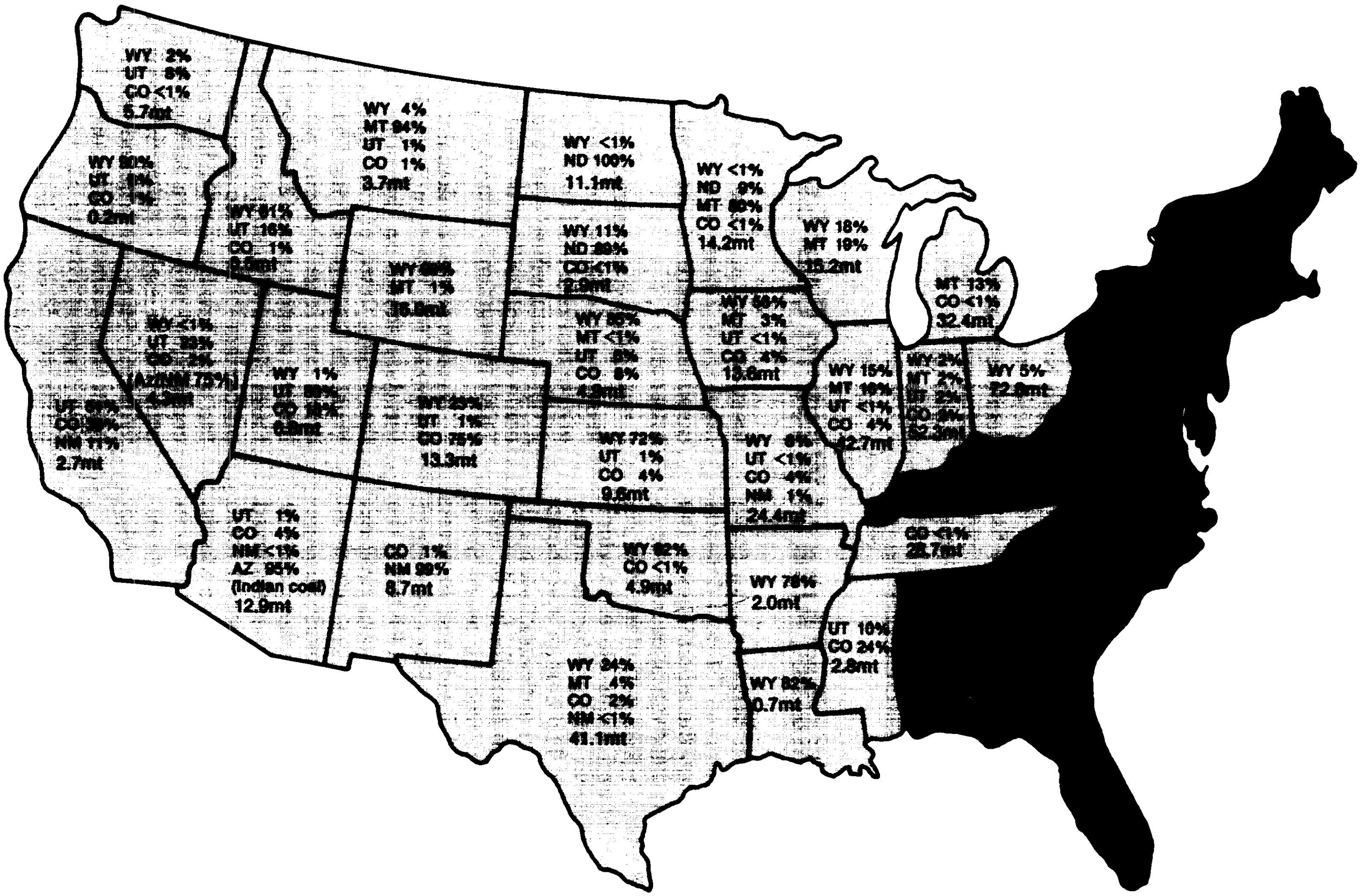
The share that each Western coal State has in fulfilling the demand for coal depends on the extent to which the advantages in the State outweigh the disadvantages relative to the other Western States and other coal regions. Figure 20 shows all the States to which the six major Federal coal-producing States shipped coal in 1979, The percentage shown in each State on the map indicates how much each Federal coal State contributed to total State use of coal. Coal went to every State west of the Mississippi River and to seven States east of the Mississippi River. In none of the States east of the Mississippi River did the combined contribution of Western coal exceed 37 percent of total coal use, which indicates that Western coal has made substantial inroads into the central market areas of the Midwest coalfields, but has not achieved market dominance* over local coal in these areas. On the other hand, west of the Mississippi River, Western coal contributed more than half of coal use within all but two States, showing a clear market dominance over Midwestern coal in these markets. The exceptions are in Texas, where local lignite has the dominant share of the coal market and in Missouri.

The relative competitive position of the six Western coal States can be measured by several indicators: total coal production, the geographic area where coal is sold, and the percentage contribution to total State coal use. This information is summarized in table 30.

Wyoming's market dominance compared to the other five Western States is evident from the data shown on this table. Wyoming has the largest level of coal production of any Western State producing Federal coal. In addition coal from Wyoming was shipped to the largest market area (22 States) and in 11 of those States Wyoming contributed the largest percentage of in-State coal use compared to the other five States. Furthermore, Wyoming contributed more than half of total in-State coal use in eight States, whereas no other Western State contributed more than this percentage in more than one State. Wyoming also shipped coal to all the Western coal-producing States except Arizona and New Mexico. Wyoming coal's cost competitiveness

*Note that the term "'market dominance"" is used here to refer to coal that has a strong competitive edge in a certain market area. The specific meaning of market dominance as used in railroad ratemaking is not meant.

Figure 20.—Market Areas of the Six Major Federal Coal-Producing States



NOTE: Only those States using coal from Montana, New Mexico, North Dakota, Colorado, Utah, and Wyoming are shown. Percentage indicates supplying State's share of user State's coal demand in 1979. Number is in millions of tons and is total State coal use/shipments received.

SOURCE: U.S. Department of Energy, *Bituminous and Subbituminous Coal and Lignite Distribution, Calender Year 1979* (Washington, D.C.: U.S. Government Printing Office, April 1980).

Table 30.—Market Relationships Between the Six Major Federal Coal-Producing States

State	1979 production (mmt)	Market area (Excludes the supplying State)	Contribution to out-of-State use[a] <10%	10-50%	>50%	No. major synfuels proposals
Wyoming	71.8	22(11)[c]	9	5	8	5
Montana	32.5	8(4)	4	3	1	2
North Dakota	15.0	2(1)	1	—	1	5
Colorado	18.1	22(2)	19	3	—	1
New Mexico	15.1	4(0)	2	1	1	1
Utah	11.8	16(3)	12	3	1	1

[a]Numbers in column indicate the number of States coal was shipped to in 1979 in each Category. Data derived from figure 20.
[b]Only projects that would produce more than I0,000 bbl/d oil equivalent of synthetic natural gas or liquids from coal are included As of January 1981 none of the proposals listed here was at a stage where production of synthetic fuels was certain Compiled from Colorado School of Mines Research Institute, Synfuels *Potential of Western* Coals, Draft, Oct 31, 1980, prepared for Off Ice of Technology Assessment, and a listing of DOE synfuel project awards In *Coal* **Week, Dec.** *22, 1980.* The number for Wyoming Includes a feasibility study being conducted by Rocky Mountain Energy Co. for a synfuel plant to develop a Federal lease in southern Wyoming and a Utah facility, neither of which is listed in either of the previously cited sources
[c]Number in parentheses indicates the number of States where there is market dominance compared to the other five States (i e., the State supplies the largest percentage of in-State coal used comdared to the other five States. but is not necessarily the dominant supplier in the State).

SOURCE Office of Technology Assessment

compared to Colorado coal along the Front Range urban corridor in Colorado, arising from transportation factors, is shown by the fact that Wyoming contributed almost one-quarter of Colorado's total coal use in 1979.

Montana is the State with the next greatest competitive advantage, as measured by total coal production. In 1979 Montana produced almost twice as much coal as Colorado, the next largest coal producer. However, it is apparent that market dominance in terms of magnitude of coal production is not necessarily accompanied by dominance in terms of geographic market area, as can be seen in the cases of Colorado and Utah. Both States ranked below Montana based on coal production, but both Colorado and Utah have very large geographic market areas compared to Montana, North Dakota, and New Mexico. In fact, Colorado shipped coal to as many States as Wyoming. However in only a few States did Colorado or Utah contribute the highest percentage of total State coal use, and in a large majority coal shipments represented less than 10 percent of total coal use.

The main reason magnitude of coal production and the size of market area do not always coincide is that utilities use much larger volumes of coal than industrial users. The low cost of surface mined coal in the Powder River basin, along with large blocks of reserves that can sustain high production rates for long-term utility contracts have been the key factors in the market dominance (in terms of magnitude of coal production) enjoyed by Wyoming and Montana. The high quality of coal in Colorado and Utah (high heat content and availability of metallurgical coal) allows a large geographic market area through sale to industrial users, spot market utility sales, and sale for blending with high-sulfur Midwestern coal. However, the high cost of producing and transporting this coal has significantly limited total production compared to Montana and Wyoming. New Mexico is perhaps the only Western State in which the relationships described here may change significantly during the next 10 years. At the present time New Mexico does not export significant amounts of coal out-of-State. However, Texas represents a significant potential market that could possibly use 20 million tons of New Mexico coal by 1990. *

Table 30 also lists the number of large-scale synthetic fuel plants that are in active planning stages in each State. All of these projects, except one in North Dakota, are still in early planning stages, and there is no cer-

*The OTA New Mexico Task Force estimated that 20 million tons or more of coal would he shipped to Texas markets in 199o. This seems to be optimistic (see discussion of forecasts of demand for New Mexico coal later in this chapter).

tainty whether, or when, they will be constructed. North Dakota has a large number of possible plants because the reserves are well--suited for conversion to synthetic gas, and water needed for cooling and conversion processes is more readily available than in other Western coal States. Wyoming has a large number of proposed projects due primarily to the availability of reserves in both the Powder River basin and southern Wyoming to support such facilities, but availability of water is more of a problem than in North Dakota. Projects in the active planning stage in the remaining four States range from one each in Colorado, New Mexico, and Utah to two in Montana.

The discussion of synthetic fuels earlier in this chapter indicated that significant levels of coal production for synthetic fuels were unlikely before 1990. The capacity in 1990 of the only two projects that were judged by OTA to have a good chance of being in operation before 1990 (the Great Plains Gasification Project in North Dakota and Panhandle Eastern's proposed gasification project in northeastern Wyoming) is 12 million tons, but it is uncertain whether either would be producing at full capacity by 1990.[32] Levels of coal production for synthetic fuels could become significant after **1990.** Coal consumption of currently proposed commercial-scale synthetic fuel plants that would use coal from the major Federal coal States would be 95 million tons per year at full capacity. Attainment of full capacity might be reached in the mid to late 1990's.

'- Boulding and Pederson, op. cit.

"Calculated from tables VI-2 and VI-3, NCA, *NCA Long-Term Forecast*, **op. cit.**

Projections of Demand for Western Coal: 1980-90 and 1990=2000

There is no way to predict with certainty the demand for coal from the major Federal coal States over the next 10 years, but it is possible to estimate demand. Numerous estimates (usually called forecasts or projections) concerning demand for coal from the West have been made for the 1985-90 period that was the focus of OTA's analysis of existing Federal leases.

Production and Demand Forecasts and Production Goals

Coal forecasts fall into two major categories: 1) production projections that are based on production commitments under existing contracts and potential production based on industry plans to open new mines and expand production at existing mines, and 2) demand projections based on computer models that assume certain conditions in coal markets and allocate coal production to different coal regions based on varying assumptions about factors such as mining and transportation costs and electrical growth rates. Production forecasts are most useful for evaluating changes in coal production over the short term (up to 5 years or so in the future) whereas demand forecasts are most useful for evaluating intermediate and long time periods (greater than 5 years). Each approach has its own advantages and limitations.

Production Forecasts

These forecasts are more directly related to the "real" world because they are based on contractual commitments and specific industry plans. Production forecasts based on industry plans for new mine openings and mine expansions are frequently high because such plans are based on individual company expectations of the share of market demand they will be able to capture. Some of the expected market share may be captured by other competitors and consequently actual production may be less than production based on industry plans. Also, coal contracts usually specify a range of possible delivery rates. If electric utilities need less than the maximum amount contracted for, then forecasts based on contracts will overstate production. For example, in the Powder River basin of Wyoming, deliveries to utilities in 1979 and 1980 averaged about 5 percent lower than would be expected based on contractual commitments. ” Production forecasts can change quite rapidly in response to changed perceptions by the coal industry of likely demand. For example the projected capacity for coal mines in Carbon, Sevier, Wayne, and Emery counties in Utah for the year 1985 dropped from 45.2 million tons in a 1977 survey to 26.5 million tons in a 1979 survey .3’ One value of production forecasts is that they can serve as an indicator of the capacity of the coal industry to respond to changes in demand.

Demand Forecasts

Based on computer models, these forecasts are not very reliable for making point forecasts for a single year because small errors in assumptions used in making the forecast can result in large differences in projected amounts. On the other hand, computer models are very useful in evaluating the sensitivity of demand for coal to changes in conditions such as the electrical growth rate and in identifying possible ranges in demand in response to different conditions. The range of possible demands generated by computer models using different assumptions can be so great that ultimately identification of a “most likely” range of demands must be based on human judgments by individuals knowledgeable about current coal market conditions and an understanding of the impact that existing trends and possible changes in these trends will have on future demand. Evaluation of forecasts from a number of different sources allows the development of a range of “most likely” demands in which a higher degree of confidence can be placed than the range of possible demands that may be generated by a single computer model.

An important element in OTA’s evaluation of the production potential from existing Federal coal leases was to identify a most likely range of demands for coal from the major Western coal regions and States with Federal leases. This identification of probable ranges in demand generally involved a four step process: 1) review of existing projections from different sources, 2) development of independent projections by OTA based on evaluation of market conditions in the specific regions or States of interest, 3) development of estimates by OTA State task forces based on review of projections identified in steps 1 and 2 and/or the development of new estimates representing the collective judgment of task force members, and 4) further evaluation and modification of task force estimates by OTA to identify a range of demands which could be compared to other estimates of production potential from existing Federal leases. *

Production Goals

OTA also paid particular attention to two sets of forecasts that became available after most of OTA’s task force meetings had been completed: 1) the August 1980 preliminary coal production goals and the January 1981 final production goals developed from DOE’s National Coal Model[36] and 2) refinements to the National Coal Model forecasts developed by ICF, Inc., using its Coal Electric Utility Model.[37] DOE’s final production goals were

“Personal communication with Gary Glass, Geological Survey of Wyoming, September 1981.

“The 1977 and 1979 Keystone Coal Surveys reported in Coal Age, February 1978; and Coal Age, February 1980, respectively.

*Special market analyses were prepared for OTAA on the Powder River basin and southern \\’yoming, Utah, and Colorado. The Utah, Wyoming. Colorado, and New Mexico task forces each discussed various ranges of likely demand in the years 1985 and 1990 ([he bases for these projections are summarized in footnotes in table 31]. In most instances 0 I'A modified the ranges discussed by the task forces to include a wider range for purposes of analyzing production potential from existing Federal leases,

"*Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995* (Washington, 1).(; .: DOE, Aug. 7, 1980); and The *1980 Biennial Update of National Regional Coal Production Goals for 1985, 1990, and 1995* (Washington, 1). C.: l) OF, January 1981.)

"The ICF forecasts are reported in *Analysis and Critique of the Department of Energy's August 7, 1980 Report entitled* “Preincreased substantially over the preliminary goals (see tables 31 and 32). The final national goals average 16.6, 15.7, and 26.0 percent higher than the preliminary goals for the years 1985, 1990, and 1995 respectively. The final DOE goal for 1985 (1.118 million tons) is very close to both the ICF and NCA forecasts (see table 32), but the 1990 and 1995 DOE final goals (1,620 million and 2,214 million tons respectively) are considerably higher than recent Projections from other sources for the same time periods. The 1990 DOE final goal is almost 300 million tons higher than the highest recent forecast shown in table 32 and the 1995 DOE final goal is almost as high as the high "likely" projection for 2000 shown on table 32.

The reason for the increases from the preliminary to the final DOE production goals appear to be primarily a clearer conceptual definition of the relationship between coal production goals and other coal production forecasts. As the report on the DOE final goals says:

> The goals developed here are based on national energy needs, existing and emerging national and international policies and laws that affect coal demand and supply, and market conditions, By comparison, energy forecasts are generally based on expected market conditions and energy laws and regulations. Since many of the assumptions underlying the production goals are based on policy initiatives to expand domestic coal production, the goals are likely to exceed coal production forecasts ., , Such a relationship is entirely appropriate.

The assumptions that were used in setting the preliminary production goals appeared consistent with a forecasting approach rather than a production goal approach to modeling. Thus, the difference between the final and preliminary goals can be attributed mostly to assumptions concerning implementation of Government policies that will increase demand for coal. * For example, the final production goals assume 1 million bbl/d oil equivalent of coal-based synfuels production in 1990 (in accordance with goals set when the Synthetic Fuels Corp. was established) and strict enforcement of the 1990 deadline in PIFUA for utility and industrial boiler conversions from gas to coal. It does not appear likely that these goals will be met by 1990. The synfuels assumptions in the final production goals substantially exceed those in recent coal production forecasts (see Synthetic Fuels section), and section 301(a) (the off gas requirement) of PIFUA has been repealed by Congress, although rising prices for natural gas will serve as as incentive for conversion from gas to coal.

The final production goals are listed in most tables and figures in this chapter to show their relationship to other production forecasts, but are not considered in detail in the evaluation of the likely range of coal demand in the major Federal coal States because the assumptions on which the final goals were developed probably overstate the impact of Government policies on increasing overall demand for coal in the United States.** However, the preliminary produc-

Continued from p. 101

liminary National and Regional Coal Production *Goals for 1985. 1990 and* **1995 (Washington D. C.:** ICF, **Inc., October 1980).** ICF **originally** developed the National Coal Model that is used by DOE 10 develop production goals., and has since refined this model into the Coal Electric Utility Model (CEUM). ICF's critique of the DOE preliminary goals identified a number of structural deficiencies in the model, and deficiencies in data and assumptions used in the mode]. Examples of structural deficiencies include such things as coal production and demand regions not coinciding with DOI coal production regions necessitating often arbitrary allocation of model outputs between regions, and distortion of transportation cost due to using average distances between large regions (e. g., transportation costs for southern Wyoming are calculated using an average distance from the Powder River basin.) Examples of deficiencies in data and assumptions include out-of-date coal reserve data in several regions, and unrealistically low assumptions about increases in transportation costs (see footnote 9). The ICF forecasts correct many of these problems, although ICF emphasizes in its analysis that no modeling forecast can be considered definitive, and that the results of forecasts must be interpreted and used with judgment. Some of the deficiencies pointed out by ICF were corrected in preparing the final goals (i.e., analysis was based on DOI supply region and higher transportation costs were used) but other changes in assumptions were made that makes comparisons between the ICF base case and DOE final production goals more difficult.

'See p. 79 for additional discussion of the conceptual distinction between Government policies that change the framework of the market system and policies that influence the market system directly to increase demand for coal.

**it should be noted that in some instances (Colorado in particular) the final production goals are lower than the pre-

Table 31.—Comparison of Demand Projections for Major Western Federal Coal Regions and States With OTA Task Force Demand Estimates

		Forecast (million tons per year)						
		DOE NCM			ICF CEUM			
Region/State	Year	Low	Medium	High	Low	Base	High	OTA task force estimates
Fort Union (North Dakota	1985	23 (29)	23 (29)	28 (29)	23	26	26	—
and Montana).	1990	31 (35)	48 (51)	73 (60)	27	27	32	—
Powder River (Montana	1985	129(187)	159(193)	223(222)	138	169	194	169 to 177
and Wyoming).	1990	186(206)	275(295)	438(412)	163	226	382	199 to 212
Rocky Mountain coal province								
Wyoming (excluding	1985	43 (55)	50 (58)	52 (67)	29	38	43	38
Powder River).	1990	55 (60)	58 (71)	63 (82)	29	36	52	42 to 51
Colorado	1985	33 (34)	36 (34)	39 (38)	26	35	51	at least 25-26
	1990	38 (28)	42 (35)	45 (43)	35	52	95	at least 32-38
Utah	1985	25 (25)	29 (30)	31 (35)	14	16	20	15 to 18
	1990	41 (36)	43 (49)	52 (63)	15	27	59	18[a] to 30[a] to 40[a]
New Mexico.	1985	32 (33)	34 (38)	40 (44)	28	30	32	about 30
	1990	43 (56)	57 (64)	61 (67)	46	58	115	**up to** 72

[a]Estimates made **for central Utah** only.

NOTE: First number IS DOE preliminary production goal which was analyzed by ICF The number in parenthesis IS the final DOE coal production goal

SOURCES. DOE Preliminary National Coal Model and ICF Coal Electric Utility Model forecasts taken from tables 3-5A, 3-5B, 3-7A and 3-7B in ICF, Inc., Analysis *and Crltique of the Departmenf of Energy's Aug 7, 1980 Report Entitled, "Preliminary National and* **Regional** *Coal Product/on Goals for 1985, 1990 and 1995",* **prepared for Rocky Mountain Energy Co, (Washington, D C.. ICF, Inc. October 1980),**

DOE Final Production Goals taken from *The 1980 Biennial* Update of *Nafional and Regional* Coal *Production Goals for 1985, 1990 and 1995* U S. Department of Energy, Leasing Policy Development Off Ice, January 1981.

Off Ice of Technology Assessment Task Force projections from following sources:

Powder River Basin and southern Wyoming. Wyoming Task Force, Oct 14-18, 1980. Most Iikely demand in Wyoming taken from G B. Glass, *Wyoming* Coal *Production and Summary of* Coal *Contracts* (Laramie, Wyo. Wyoming Geological Survey, 1960), and likely high demand taken from J J. Sebesta, *Demand for Wyoming Coal 1980-1991 Based Upon Protected* Utility Coal *Market* (Washington, DC.. Office of Technology Assessment, October 1980) with slight modifications by the Wyoming Task Force as reported in J. R. Boulding and D. L. Pederson, *Development and Production Potential of Undeveloped Federal Coal Leases and Preference Right Lease Applications in the Powder River Basin and Other Wyoming* Coal *Basins* (Washington, D.C. Off Ice of Technology Assessment, 1981), Likely high demand for Montana Powder River Basin taken from J. J, Sebesta, *Demand for Montana* Coal *1980-1991 Based Upon Projected* Utility Market **(Washington, D C.. Off Ice of Technology Assessment, October 1980). Most likely projections for the whole Powder River Basin derived by adding Sebesta's Montana projections to Glass' Wyoming projections, and likely high demand derived by adding Sebesta's Wyoming and Montana projectlons Note that the Glass and Sebesta projections for southern Wyomlng in 1985 are the same, so there IS no range** shown

Colorado Estimates by Colorado Task Force, Sept 22-24, 1980, represent minimum production expected from existing **contracts, mine plans, and undeveloped leases, as reported in J E Martin, Market Factors** *and Production Contingencies Determining the Present and future Demands for Colorado Coal* (Lakewood, Colo.: Colorado Energy Research Institute. December 1980),

Utah Off Ice of Technology Assessment Task Force, Feb. 2529, 1980 Low to high range was developed by the task force Most likely production IS from F Hachman, *Market Factors Associated With the Assessment of Development Potential of Federal Coal Leases in Utah,* prepared for the Office of Technology Assessment, 1980 Total excludes production from Alton Mine or for the Allen-Warner Valley Complex

New Mexico OTA New Mexico Task Force, Aug. 26-27, 1980 Estimates developed by task force as reported in *The Development Prospects for Federal* **Coal Leases** in New Mexico 1980-7990 (Washington, D C : Office of Technology Assessment, November 1980) The 1990 projection was based on a number of optimistic assumptions including that a major new market for New Mexico steam coal (about 20 million tons per year) wiIl develop in Texas and the gulf coast, and that demand for electricity in New Mexico and the Western region wiIl grow at 4 percent during this period

tion goals are more comparable with other coal production forecasts and are analyzed in this chapter as such.

Table 31 summarizes the DOE, ICF, and OTA task force projections for the Fort Union and Powder River coal regions, southern Wyoming, Colorado, Utah, and New Mexico.* Figure 21 compares these projections schematically for the Fort Union and Powder River regions and southern Wyoming, and figure 22 illustrates these projections for Colorado, Utah, and New Mexico.

It should be kept in mind when comparing the DOE, ICF, and OTA task force forecasts that they were derived by very different methods, The model forecasts are based on varying assumptions concerning factors affecting the overall demand for coal in the United States: this demand is then allocated

liminary goals. This is apparently due to the fact that refinements in the model (such as increasing transportation costs) offset the other assumptions that increased the overall national (():] 1 production goals.

*Since most coal production from the major Federal coal Slates will come from the Powder River region (50 percent or more), demand projections for this area were analyzed in greater detail by OTA. Projections discussed in this chapter include only the DOE, 1(; F'. and OTA task force projections to allow general comparison with projections for the other Federal coal regions and St;] tes. Analysis of other projections for the Powder River basin can be found **in** ch. **7.**

Table 32.–Demand and Production Forecasts for Coai for the United States: 1985-2000
(millions of tons)

	1985			1990			1995			
	Low	Medium	High	Low	Medium	High	Low	Medium	High	2000
EIA production forecasts (1979)	1,129	1,130	1,129	1,305	1,343	1,353	1,592	1,715	1,718	—
Council on Environmental Quality (1979)	–	–	–	–	—	—	—	—	—	899-1850[a]
Exxon (1979)	–	–	–	–	1,285	–	—	–	—	2,219
DOE preliminary production goals (1980)	880	963	1,080	1,089	1,375	1,762	1,238	1,718	2,322	—
ICF CEUM forecasts (1980)	915	1,016	1,082	1,122	1,300	1,791	1,380	1,756	2,976	—
Data Resources, Inc. (1980)	–	987	–	–	1,290	–	—	1,617	—	1,931
National Coal Association (1981)	878	1,015	1,131	1,092	1,345	1,540	—	—	—	—
DOE final production goals (1981)[b]	1,040	1,118	1,245	1,270	1,620	1,986	1,519	2,214	2,766	

[a]Range is for low and high energy growth scenarios analyzed by CEQ. Numbers are recalculated from table 6 using an average of 20 million Btu/ton rather than the 23 million Btu/ton used by CEQ in order to account for declines in average coal heat content as Western coal production increases. The 20 million Btu/ton is taken from the national average projected in 1990 by Congressional Research Service project Interdependence: U.S. and World Energy Outlook Through 1990, Senate Committee on Energy and Natural Resources, Pub. No. 95-31 (Washington, D. C.: U.S. Government Printing Office, 1977).
[b]Included for comparison to forecasts. See discussion in text for difference between the DOE production goals and production forecasts.

SOURCES (in order listed in table):
Table 4.26, V.III Energy Information Administration, *Annual Report* to *Congress, 1979* (Washington, DC.: U.S. Government Printing Office, 1980).
Council on Environmental Quality, *The Good News About Energy* (Washington, DC.: U.S. Government Printing Office, 1979).
Exxon Co., U.S. *Energy Outlook 1980-2000* (Houston, Tex. Exxon USA, December 1979), p. 12.
U.S. Department of Energy, *Preliminary National and Regional Coal Production* Goals *for* 1985, 1990 *and 1995* (Washington, DC.: DOE, Aug. 7, 1980).
ICF, Inc. *Analysis and Critque of the Department of Energy's August 7, 1980 Report Ent/tied "Preliminary National and Regional Coal Production* Goals *for* 1985, 1990 *and 1995"* prepared for Rocky Mountain Energy Co. (Washington, D, C.: ICF, inc. October 1980),
Data Resources, Inc., production forecast as reported in Coal Week, Sept. 22, 1980.
National Coal Association *NCA Long-Term Forecast* **(Washington, D. C.: NCA, March 1981).**
U.S. Department of Energy, *The 1980 Biennial Update of National and Regional Coal Product/on* Goals *for* 1985, 1990, *and 1995* **(Washington, D.C., DOE,** January 1981).

to different regions or States. A fundamental weakness of all computer models is that they are least accurate when results are disaggregate to small geographic regions. The reason for this is that when modeling complex systems, simplifying assumptions must be made. At the aggregate level, simplifying assumptions that may distort results one way or another tend to cancel each other out. At the specific geographic level, small changes in assumptions may create large shifts in projected demand between regions.[38] It must also be realized that models reflect the assumptions, perceptions and biases of the model manager. In addition, models tend to seek optimal (least cost) solutions to fuel procurement and the entire system tends to approach a general equilibrium solution. Rarely, if ever, are these conditions totally achieved in reality.

The OTA task force estimates, on the other hand, were developed based on analysis and judgments by a group of people familiar with the effect that specific conditions in the region or State could have for the demand for coal from that area. The advantage of this approach is that it reflects a sensitivity to local conditions that a computer model cannot have. The disadvantage of this approach is that events or conditions outside of the State or region might affect demand for coal from that region in ways not anticipated by the task force. There is also a possibility that individuals closely associated with development in a region or State may underestimate the effects of competition from another region or State.

The value of looking at both kinds of forecasts is that the two can be used as a check against each other. If several different forecasts are in close agreement, then it can be expected with a reasonably high level of confidence that actual production will be close to the levels forecasted. On the other hand, if different forecasts of the "most likely" level of production differ substantially, then a closer look at the forecasts is merited to try to understand the reasons for the differences.

Given the inherent uncertainty in forecasts, it is necessary to identify a range* to

[38] Additional discussion of this problem can be found in the ICF report cited previously and also in Energy and Environmental Analysis, Inc., Feasibility of Using Coal Market Projections To Appraise Potential Production of Federal Coal Leaseholds, draft report prepared for OTA, 1980.

* It should be noted that this range is distinctly different from the kinds of ranges developed by computer models such as the

account for contingencies and factors that cannot be predicted, The rest of this section examines more closely the different forecasts in the regions and states shown in figures 21 and 22, identifying, where possible, the reasons for divergence between the forecasts.

Fort Union Region

Virtually all production from this region comes from North Dakota; only 0.5 million tons were produced in the Montana portion of the Fort Union region in 1979, compared to 15.0 million tons in North Dakota. The DOE and ICF forecasts are in close agreement in 1985 (see fig. 21) but diverge widely in 1990 with the ICF high forecast nearly the same as the DOE low forecast. OTA did not convene a task force for this region, so no projections are available for comparison, but OTA's evaluation of existing leases found that 30 million tons would be needed to meet the requirements of existing and new coal conversion facilities currently planned or under construction. Given the leadtime necessary to construct these large facilities, it appears that demand for Fort Union coal in 1990 is likely to be closer to the ICF forecast than the higher DOE forecasts.

Powder River Basin

All three forecasts show quite good agreement for 1985 (see fig. 21) with the ICF base case of 169 million tons exactly the same as the OTA task force most likely production estimate, and DOE's medium forecast 10 million tons lower. However, OTA's likely high demand in 1985 is considerably lower than the DOE and ICF high forecasts. In 1990 there is considerable divergence between the three forecasts, with OTA's likely high estimate of 212 million tons being 14 million tons lower than the ICF base case, and 63 million tons lower than DOE's medium forecast. The main reason the DOE forecast is so much higher than the ICF forecast is that the DOE forecasts included unrealistically low increases in transportation costs that were modified in the ICF forecast. OTA used the DOE medium forecast as its high-demand scenario for analysis of production potential of leases, even though it is probably beyond the range of "likely" high production levels. (See ch. 7 for further discussion of demand for Powder River basin coal,)

Southern Wyoming

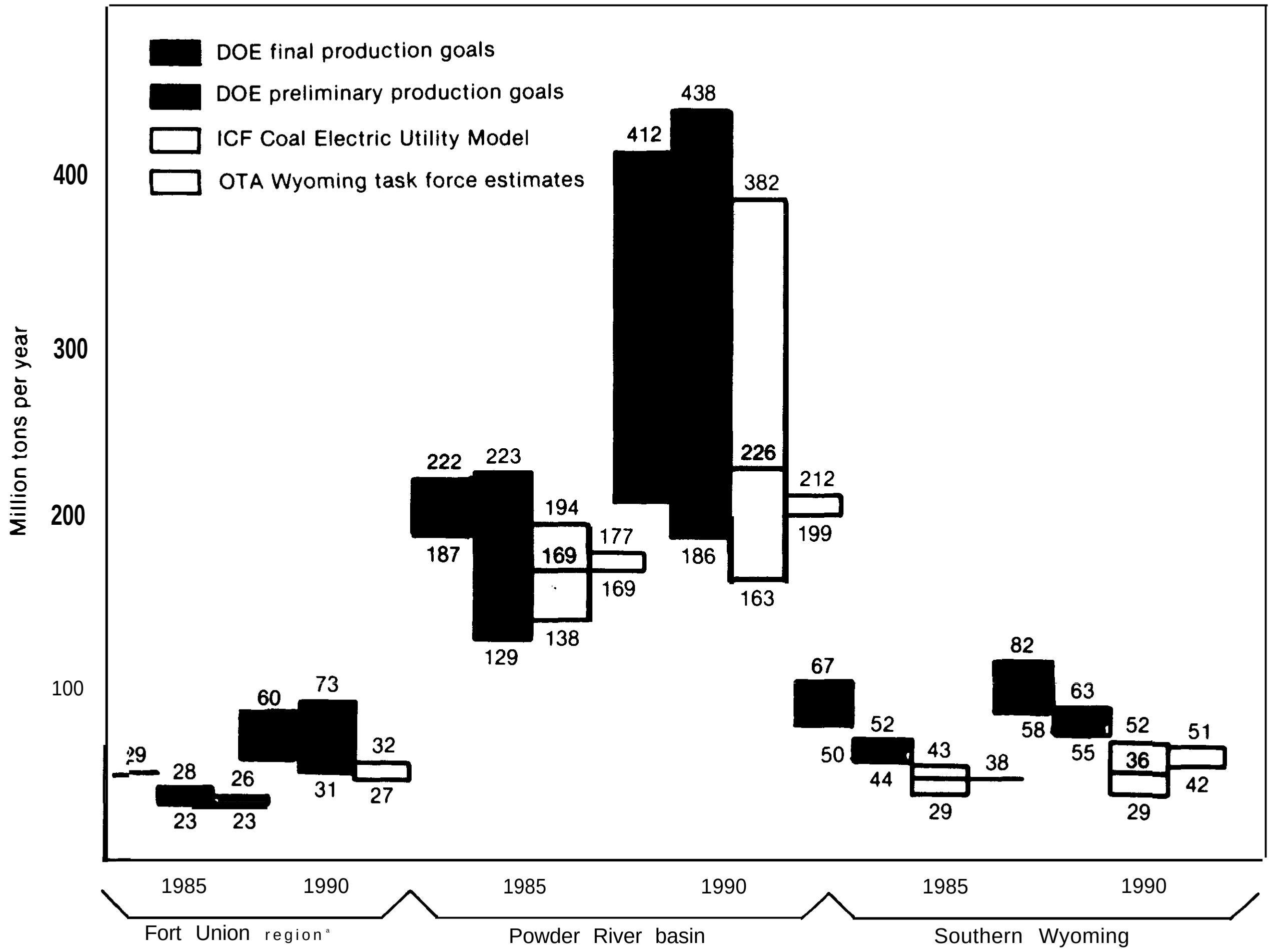
The OTA task force and ICF projections of 38 million tons for southern Wyoming are exactly the same in 1985 (see fig. 21) and are considerably lower than DOE's midrange forecast of 50 million tons, In fact, DOE's midrange forecast for 1985 is almost the same as the OTA likely high estimate of 51 million tons for 1990. The primary reason for the high DOE numbers is that the DOE model considerably understates transportation costs from southern Wyoming because distances in the model are calculated using a centroid located in the Powder River basin, In 1990, DOE's low forecast is still higher than ICF's high forecast (for the reason just mentioned) and the OTA range of likely to likely high production falls within the midrange to upper range of the ICF forecast. For reasons that are not clear, the ICF base forecast drops below its 1985 forecast (from 38 million to 36 million tons) and is thus lower than the OTA task force projection.

Colorado

The DOE and ICF forecasts for 1985 are very close (36 million and 35 million tons respectively); the OTA task force estimate in this case is an estimate of minimum demand. For 1990, the OTA task force estimate of 32 million to 38 million tons is comparable to the ICF and DOE low forecasts, The ICF base forecast is considerably higher than the DOE

DOE and ICF forecasts shown in table 31, These ranges are indicative of the sensitivity of demand to changes in assumptions that are plugged into the model, but are not necessarily indicative of what is likely to happen in the real world. Even though the low to high ranges identified by OTA for analysis of existing Federal leases are narrower than the model ranges, it is likely that demand for 1985 and 1990 will be within the range. After 1990 uncertainties and ranges in forecasts increase considerably (see final section of this chapter]; OTA did not attempt to develop most likely ranges of demand for the post-1990 period.

Figure 21.—Demand Projections for the Fort Union and Powder River Coal Regions and Southern Wyoming, Compared to OTA Task Force Estimates



[a]No OTA protection

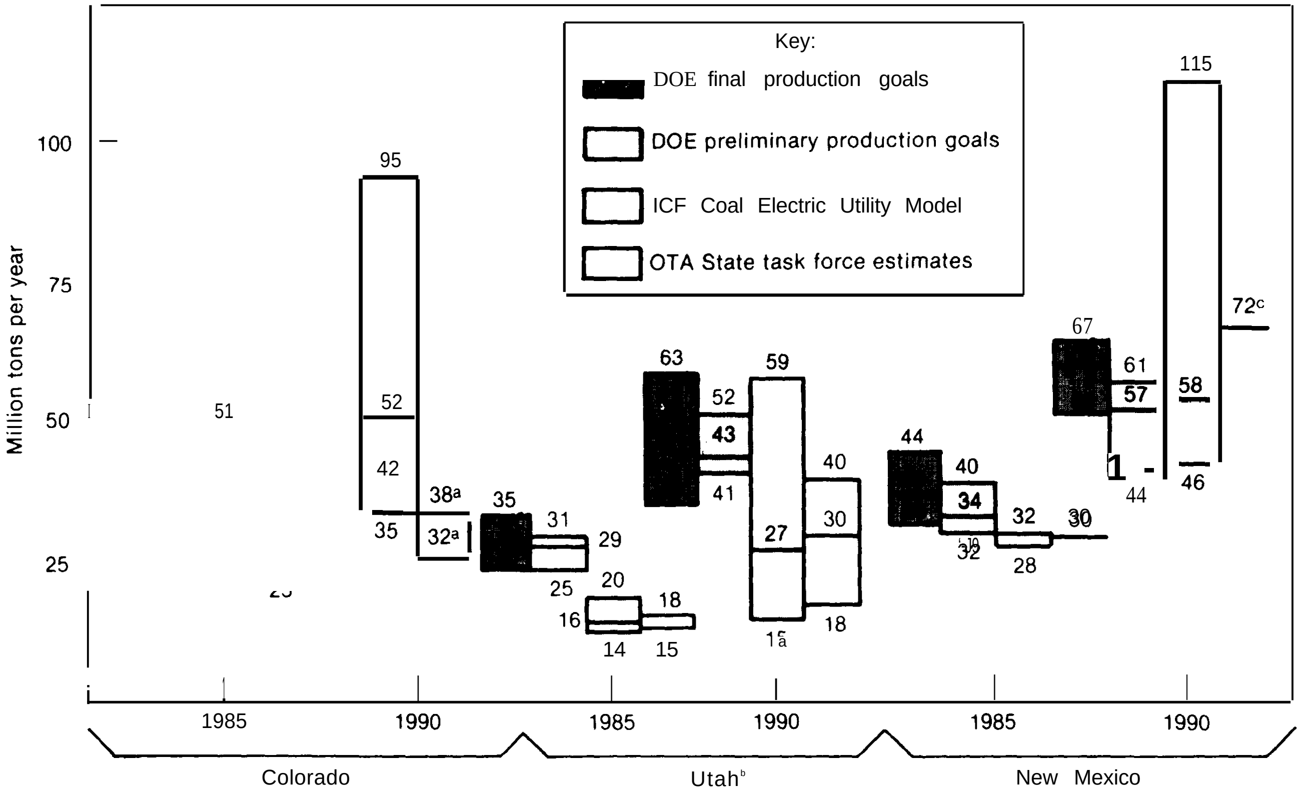
SOURCE Table 30

medium forecast (52 million v. 42 million tons). The OTA task force estimate was conservative; and although the DOE and ICF models may not be sensitive to the especially disadvantageous situation in Colorado with respect to transportation costs, as discussed earlier in this chapter, demand in 1990 may be closer to the DOE range than the OTA range.

Utah

The forecasted ranges by DOE and ICF do not overlap at all in 1985. The OTA task force estimated that 1985 production in Utah would come from mines currently in operation or construction. In 1980, the State geological survey estimated planned 1985 production would be between 15 million to 18 million tons. Probably the ICF base of 16 million tons and the DOE medium forecast of 29 million tons is a reasonable low to high range. In 1990 the ICF base projection and OTA mis-estimate are close (27 million and 30 million tons respectively) but are considerably lower than the DOE midrange forecast of 43 million tons. The DOE medium forecast is quite close to the OTA high estimate of 40 million tons.

Figure 22.—Demand Projections for Colorado, Utah, and New Mexico, Compared to OTA Task Force Estimates



[a]Figures shown are low ranges.
[b]OTA demand estimates for-central Utah only
[c]Figure represents maximum likely demand.

SOURCE Table 30

New Mexico

The ICF base forecast and the OTA estimate in 1985 are exactly the same (30 million tons) and 4 million tons lower than the DOE forecast, which indicates good agreement among all three forecasts. In 1990 the DOE and ICF forecasts are very close (57 million and 58 million tons respectively) but are considerably lower than the OTA task force estimate of 72 million tons. The OTA task force estimate was admittedly an optimistic estimate, and assumed that in the 1990's New Mexico would be shipping 20 or more million tons of coal to Texas markets. A substantial portion of Texas exports would come from captive mines. The OTA task force estimate has been categorized in table 31 as a potential high production level rather than a "most likely" level of production. If it is assumed that New Mexico exports a more modest level of 10 million tons per year to the South-Central States in 1990, the OTA estimate would drop to 62 million tons, which is close to the DOE and ICF projections.

Comparisons of Forecasts

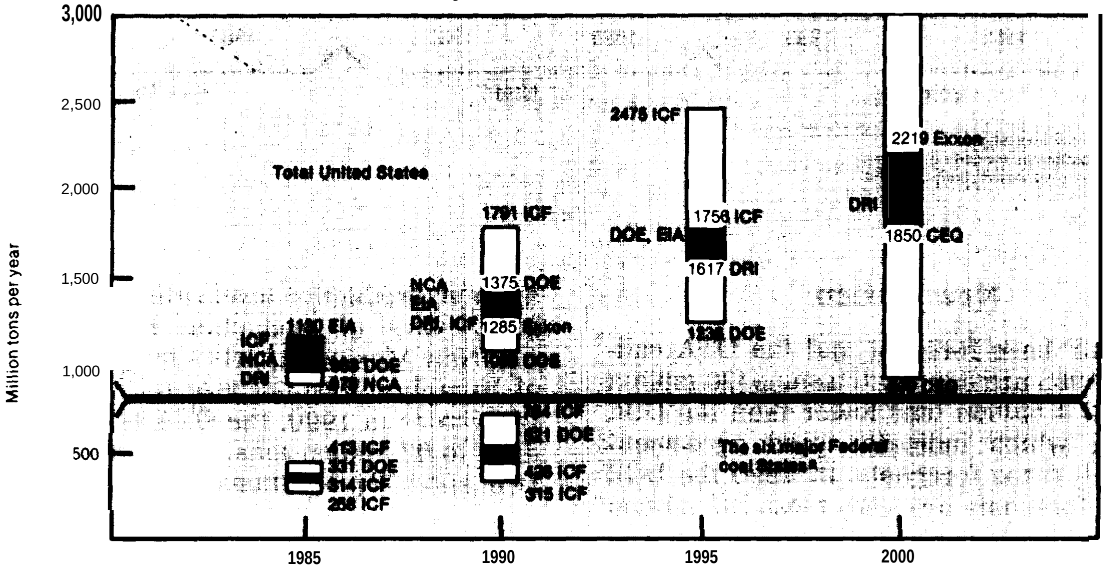
The comparisons between the three sets of forecasts for the major Federal coal regions and States allow a few generalizations. First, compared to the DOE and ICF forecasts, the OTA task force estimates are quite consistently lower than, or near the lower of the mid-range forecasts of the two models. Although the specific reasons for this vary, this is probably generally because the OTA task force estimates are more sensitive to some of the factors discussed earlier in this chapter that have weakened the competitive position of Western coal. Another reason is that the OTA task forces quite uniformly did not consider synthetic fuels or foreign exports to be significant sources of demand before 1990. Should demand from these sources materialize to a greater extent than expected by the task forces, demand might be higher than the "most likely" levels estimated. However, inclusion of the higher midlevel forecasts from other sources increases the upper range of the "most likely" estimates sufficiently that possible demand from these sources is likely to be adequately accounted for. A second generalization is that the 1990 forecasts from all sources tend to have wider ranges than the 1985 forecasts. This can be attributed to the higher levels of uncertainty in the factors affecting demand 10 years from now compared to 5 years from now.

Demand for Western Coal: 1990=2000

Forecasts for the demand for Western coal after 1990 have a much higher level of uncertainty than the period from 1980 to 1990, and OTA has not tried to conduct any quantitative analysis for the 1990's. However, a number of demand forecasts are available for the United States through 2000, and these can be used to get a general idea of possible trends and development through to the end of this century.

Table 32 shows eight forecasts made in the last few years for total U.S. coal production in 1985, 1990, 1995, and 2000. Elements of these forecasts are compared schematically in figure 23. Also shown in figure 23 for 1985

Figure 23.– Demand and Production Forecasts for the United States: 1985-2000 and the Six Major Federal Coal States:[a] 1985-90



Key:

Range of "most likely" forecasts | **Range of low and high forecasts**

CEQ Council on Environmental Quality
DRI Data Resources, Inc.
DOE Dept. of Energy National Coal Model[c]
EIA Energy Information Administration
ICF ICF Coal Electric Utility Model
NCA National Coal Association

[a]Colorado , **Montana. New Mexico, North Dakota, Utah, and Wyoming**
[b]Intermediate high and low forecasts **from the various sources not shown.**
[c]**DOE's 19S0 preliminary production goals are shown here rather than the final goals because they are more comparable with other production forecasts See discussion p 100**

SOURCE Table 32.

and 1990 are the DOE and ICF forecasts for the six major Federal coal States combined. From 1990 to 2000 both the range of "most likely" forecasts in figure 23 (shaded) and the range of low to high increase greatly, reflecting the greater uncertainties inherent in forecasting over longer periods of time. In fact the low forecast in 2000 (899 million tons) made by the Council on Environmental Quality (CEQ), is lower than the lowest medium projection in 1985 (963 million tons by DOE) (see table 32). The CEQ forecast is based on a low-energy growth scenario in which conservation is the main focus of national energy policy.

Electrical growth rates after 1990 are generally projected to be similar to or lower than growth projected for the 1980-90 decade. For example, Exxon's projection of 5.3 percent from 1978 to 1990 drops to 2,9 percent from 1990 to 2000. ICF projects electrical growth rate continuing at 3.0 percent from 1990 to 1995. Consequently, according to these projections of electrical growth rate, rates of increase in coal demand for utility use can be expected to be somewhat lower or about the same in the last decade of this century, although conversion of oil and gas to coal may offset lower overall electrical growth rates.

Significant areas of potential new demand for western coal after 1990 include: 1) synthetic fuels, 2) industrial boilers, and 3) foreign export. Possible (but not necessarily probable) levels of demand for Western coal for these uses after 1990 could total on the order of 250 million tons, which is more than the total of 231 million tons produced in the West in 1979. Coal consumption for synthetic fuels plants could be around 100 million tons (see p. 100), Incremental demand for industrial boilers from 1990 to 2000 in the whole United States could be on the order of 100 million tons (assuming the 7-percent growth in demand projected by NCA from 1979 to 1990 continues) of which perhaps half might be supplied by the West, Foreign exports could possibly range from 50 million to 100 million tons,

Most of the projections shown in table 32 are not disaggregated to a level that allows a close look at trends in forecasted production from the six major Federal coal States, but most forecasts make a breakdown between production from the West and East. Some trends are evident when Western coal production is translated into percentage of total U.S. coal production (see table 33). All the forecasts show a steady increase in the West's share of total U.S. coal production between 1985 and 2000. A significant part of this increase is due to the fact that more Western coal must be mined to make an equivalent contribution to U.S. energy needs compared to Eastern coal. For example, the CEQ forecast did not take this into account, and adjusting their forecast to correct for the lower heat content of Western coal increased CEQ's low coal demand scenario in 2000 from 782 million to 899 million tons (see footnote, table 32).

A comparison of the different forecasts for any given year in table 33 shows that there is a considerable range in the percentage that is projected to come from the West. In 1985 the West's share of total U.S. production is projected to range from 33 to 43 percent and in 1990 from 38 to 49 percent. The Energy Information Administration production forecasts, which are the lowest for these 2 years agree with the most recent forecast in table 33 made by NCA and it seems likely that the growth rate of Western coal production will increase at a lower rate than the various model forecasts (DOE, ICF, and DRI) indicate. In 1995 the forecasted percentage of Western coal production begins to converge (from 47 to 52 percent) with a mid point of 49.5 percent and in 2000 Western coal production is projected to exceed so percent of U.S. production.

In table 33 the numbers in parentheses indicate the percentage of total U.S. coal production that would come from the six major Federal coal States. It is clear from these percentages that these States account for most of the production from the West, but the DOE and ICF forecasts show production from

Table 33.—Forecasted Changes in Contribution of Western Coal to Total U.S. Production

	Western coal production as percent of total United States[a]			
	1985	1990	1995	2000
EIA production forecasts (1979) . .	33	38	47	—
Exxon (1979)	—	45	—	53
DOE production goals (1980)	40(34)[b]	46(38)	49(39)	—
ICF CEUM forecasts (1980)	38(30)	44(33)	50(38)	—
Data Resources, Inc. (1980)	41(34)	49(41)	52(44)	55(46)
National Coal Association (1981) .	34	38	—	—
DOE final production goals (1981)	43(32)	47(32)	52(36)	—

[a]Western coal includes all production west of the Mississippi River. In addition to the six major Federal coal States, Western production includes coal mined in the Western Interior coal province, the Gulf Coast lignite province, Arizona, Washington, and Alaska. In 1979, Western coal production was 28 percent of total U.S. production and production from the six major Federal coal States was 21 percent of total production.
[b]Number in parentheses is production from the six major Federal coal States (Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming) as a percentage of total U.S. production.

SOURCE. See table 32

the major Federal coal States growing at a somewhat slower rate than total Western coal production between 1985 and 1995. The DRI forecast shows production from the major Federal coal States growing at a slightly faster rate than total Western coal production between 1985 and 1995. It is interesting to note that the final DOE production goals indicate a relatively smaller proportion of production from the major Federal coal States compared to the preliminary goals (i.e., 32 v. 38 percent in 1990). The final goals are considerably higher than the preliminary goals, but the assumed higher cost increases in transportation appear to have restricted the share that the Federal coal States obtain of the higher goals.

Summary

The analysis of the various factors affecting demand for coal from the major Federal coal States in this chapter allows a few general conclusions:

1. The demand for coal from the major Federal coal States will continue to grow at a faster rate than the total growth in the demand for coal in the United States due primarily to the low cost of mining this coal compared to the Midwest and Appalachia, and to the fact that more coal must be mined to meet equivalent energy needs because of the lower heat content of the coal.
2. However, because of several factors (increasing transportation costs and present SO_2 emission standards being among the most important) the competitive position of Western coal in the Midwest and South-Central United States (which are the major centers of demand for Western coal) will not be as favorable during the next 10 years. as compared to the previous 10 years. The net effect of these factors, combined with downward revisions in projected growth rates for electricity means that the growth in demand for Western coal will probably not be as great as some earlier forecasts had predicted.
3. After 1990 Western coal is expected to continue increasing its share of total U.S. coal production, but total Western coal production may increase at a slightly faster rate than coal production from the major Federal coal States. Offsetting slowed growth in demand because of possible reduced electrical growth are a number of possible new markets for Western coal for which precise demands are difficult to predict, but which could potentially be large consumers of coal. These potential major new markets for Western coal after 1990 are synthetic fuels, industrial boiler conversions, and exports to Asia.

CHAPTER 6

Development Potential and Production Prospects of Federal Coal Leases

Contents

List of Tables

List of Figures

CHAPTER 6

Development Potential and Production Prospects of Federal Coal Leases

This chapter presents the results of OTA's assessment of the development potential and production prospects of Federal coal leases. These results constitute OTA's response to the first and second of its four charges in the Federal Coal Leasing Amendments Act of l976 (FCLAA): an analysis of all mining activities on Federal leases and of the present and potential value of existing Federal coal leases.

Introduction and Summary of Findings

This chapter presents OTA's **estimate of** the amount of coal that could be produced from mines with Federal leases in the next 10 years. The estimates of the potential production from Federal leases made in this report are not forecasts of the coal that would be produced at a given price or a given demand. They are estimates of the total amount of coal that could be produced from currently operating and proposed Federal mines and from those undeveloped Federal leases that have characteristics comparable to operating mines in the same region. Coal from these leases would thus be likely to be produced at a price that is competitive with other mines in the same area, (Most analyses of coal market trends in the 1980's, including those used in OTA's State task forces, have projected that demand for Western coal will expand significantly while the price of coal will remain stable during the next decade with primary increases because of inflation.) If the projected increases in demand fail to materialize or if holders of existing leases do not capture a proportionate share of any expanded market, then not all the leases that could technically and economically be developed will be brought into production, Under those circumstances, OTA's production estimates will be higher than actual production from existing leases.

The years 1986 and 1991 are key years in Federal coal development. All Federal coal leases issued before the passage of FCLAA must meet the diligent production requirement of 2½ percent of recoverable reserves by June 1, 1986, under Department of interior (DOI) regulations. Failure to meet this requirement could result in cancellation of the lease. However, the diligence period may be extended for up to 5 years to June 1, 1991, if certain conditions are met (see ch. 9).

The production estimates for these two key years are based on resource potential and other factors that will affect output, e.g., 1) the lessees' plans, financial capability, and mining experience; 2) geological conditions on the lease: 3) mining and reclamation conditions on the lease; 4) possible environmental permit restrictions; 5) availability of transportation; 6) socioeconomic impacts and limitations; and 7) potential markets and demand for Western coal.

Mining plans are an excellent source of detailed information for analyzing potential production and assessing specific problems concerning the development of Federal coal leases, The submission of a mining and reclamation plan to the U.S. Office of Surface Mining (OSM) and the U.S. Geological Survey (USGS)* is a necessary step in the process of mine development and coal production, As the first step in its analysis, OTA has grouped leases in three categories: 1) those with approved mine plans; 2) those with mine plans submitted and pending approval; and

*Both surface and underground mines must submit mine plans to thc Office of Surface Mining,

3) those with no submitted mine plan, which are referred to as "undeveloped leases" in this report.

OTA examined each mine plan to determine: 1) major geological, mining, and reclamation conditions associated with the operation; 2) the lessee's mine design capacity and projected annual production over the next 10 years; and 3) likelihood of the mine's production meeting diligence requirements, Mine design capacity is the maximum annual production of coal that all facilities located at a mine can support.

OTA analyzed undeveloped leases, (those without mine plans) differently. These leases were grouped in blocks of adjoining leases held by the same lessee, Based on geological and technical characteristics of the blocks, each lease block was assigned favorable, uncertain, or unfavorable development potential. These assignments were made in part by comparing the reserves, coal quality, and the mining and reclamation conditions of undeveloped leases with similar mines in the area, Leases that had questionable development potential based on the criteria were further evaluated for their potential to be integrated into an adjoining mine or to be combined with other undeveloped reserves.

Those leases with favorable or uncertain development potential were analyzed block by block to assess the factors that could affect their rate and level of development. Factors examined included coal markets and demand. Production estimates were then developed for each lease block.

A more detailed description of the methodology for evaluating development potential and estimating production is given in chapter 2.

Summary of Findings

As of late 1980, there were 502 Federal coal leases in the six Western States of Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming. * These 502 leases, 89 percent of the 565 existing Federal coal leases, contain 16.3 billion tons of recoverable reserves, over 98 percent of the total of 16.5 billion tons of Federal coal currently under lease; they account for over 99) percent of Federal coal production.**

The 502 Federal coal leases in these six States are grouped as follows:***

1. 182 leases with 7.3 billion tons of recoverable reserves (# percent of the total leased reserves) are in approved mine plans.
2. 117 leases with 2.5 billion tons of recoverable reserves (15 percent) are in pending mine plans. ****
3. 203 leases with 6.4 billion tons of recoverable reserves (39 percent) are not in mine plans. (These leases, plus five leases in pending mine plans in Wyoming are called undeveloped leases.)

Of these 208 undeveloped leases (203 leases with no mine plans and the five Wyoming leases in pending mine plans), 80 leases containing 4.1 billion tons of recoverable reserves have favorable prospects for develop-

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*The leases issued in early 1981 under the new Federal coal management program are not included in I h is tot a I and were not considered in this study. See also p. 164 of this chapter, for a discussion of the 46 Federal leases i n Oklahoma.

* *Coal from Federal coal leases is referred to as Federal coal. A mine that includes a Federa 1 lease is called a Federal mine. Sometimes, for the sake of efficiency of recovery or economy of opera t ions, in tervening Sta te or private coal is mined with Federal lease(s) in the same m inc. This practice is the rule in southern Wyoming and North Dakota, for example. Thus, many Federal mines produce both Federa I and non-Federal coal. A mine which conta ins no Federal coal is called a **non-Federal mine,** Total coal production in a State or region is thus the sum of: 1) Federal coal production from Federal mines **plus 2)** non-Federal coal production from Federal mines, **plus 3) non-**Federal coal production from non-Federal mines.

** *Five small leases, isolated from principal coal-producing regions, t h ree in Montana and two in Wyom i ng, were not a na - lyzed in this chapter, hut are included in these totals. Four are undeveloped leases with little likelihood of being developed. One is a producing lease. These leases do not appear in the tables in this chapter,

****Five leases in pending mine plans in Wyoming are included in this total. Because of the preliminary nature of the mine plans a t the time the a nalvs is was done, these leases are. however, analyzed as undeveloped leases later in this chapter.

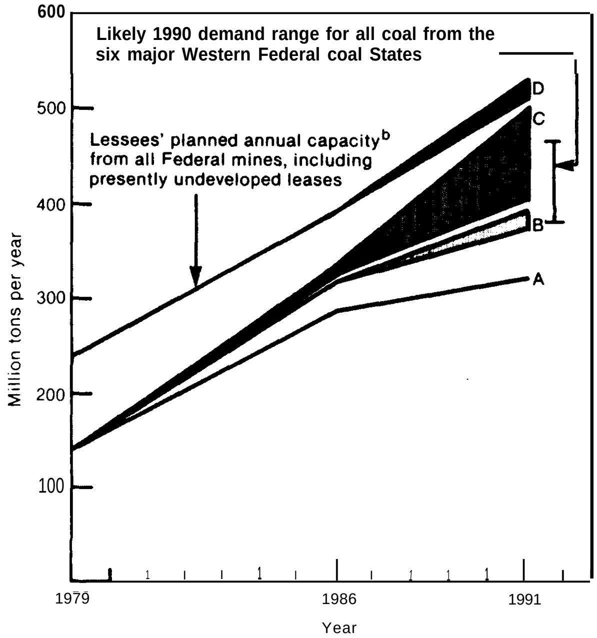
ment by 1991. The majority of these reserves are concentrated in the Wyoming portion of the Powder River basin (3.2 billion tons of surface-minable reserves) and in the Uinta region of Utah (0.4 billion tons of underground reserves). In almost all cases, the lessees are actively developing these leases.

Another 65 leases containing 2.3 billion tons of recoverable reserves have uncertain prospects for development by 1991. The large majority of these reserves (about 90 percent] are about evenly divided among the Kaiparowits Plateau coalfield of southwestern Utah, the Green River region of Colorado and the Wyoming portion of the Powder River basin. Development depends on factors such as pace and scale of construction of associated powerplants or synfuel projects, development of in situ gasification, availability of additional Federal reserves from pending preference right leasing applications (PRLAs] or from new lease sales, construction of transportation systems and lessee development priorities.

Finally, 63 leases with approximately 0.5 billion tons of recoverable reserves are unlikely to be developed. Most of these leases lack sufficient minable reserves of marketable quality to be developed as new mines. Many also have difficult mining conditions that would make them expensive to develop, and some are located outside active mining areas and lack adequate transportation. Because they are unlikely to be developed, any production is unlikely from these leases.

Production from existing Federal coal leases is likely to increase substantially over the next 10 years, Planned production capacity for 1986 for Federal mines is 400 million tons per year; for 1991, over 535 million tons per year (see fig, 24). OTA estimates that production from Federal mines could range between 410 million and 500 million tons per year in 1991 depending on markets, synfuels development, and rail construction. According to the plans of lessees, about 65 percent of 1991 upper limit projected production (325 million tons) is expected to be mined from Federal mines with currently approved mine

Figure 24.— Potential Production From and Planned Capacity of Federal Mines Summed Over the Six Major Federal Coal States[a]



Potential annual production:[b]

A Lessees' planned annual production from Federal mines in currently approved mine plans only

B Lessees' planned annual production from Federal mines in currently approved and pending mine plans

C The sum **of E?, above, plus estimates of potential production from presently undeveloped Federal leases**

[a]**Wyoming, Montana, Colorado, Utah, New Mexico, and North Dakota**

[b]**Planned capacity for a given year** IS **the upper limit to potential production in that year (although an even higher total capacity might be attainable in a very strong market for coal) In many cases (e g currently approved mines In the Powder River basin in 1991), the lessees' production plans call** for them to **pro-** duce at or near **capacity In other cases, even optimistic production plans fall short of using planned capacity to the full Some mines, particularly newer mines in the Southern Rockies will not attain thelr** planned maximum capacity until the 1990's. In all cases, however the capacities planned for 1986 or 1991 were used in deriving fig. 24, above, not the higher numbers for planned maximum capacities in the post 1991 period For most **Federal** mines in the Southern Rockies the planned productions for 1986 and 1991 are close to the planned **capacities for those years**

Explanation of ranges

C. 92 million **ton per year range in 1991**

65 mty = Dominant uncertainty is **the development of markets for the coal**

22 mty Dominant uncertainty IS **the construction of two railroads one to the Kaiparowits Plateau in Utah (14 mty) and one to the Star Lake Bisti area of New Mexico (8 mty)**

5 mty Dominant uncertainty IS **the schedule of synfuels development**

D: 22 million ton per year range in 1991

Dominant uncertainty IS the construction of the two railroads mentioned above under C

SOURCE Off Ice of Technology Assessment

plans. About 14 percent would come from Federal mines with currently pending mine plans (69 million tons). The remaining 22 percent (109 million tons) is projected to come from presently undeveloped leases. Actual production in 1991 could fall below this range, however, because of competition with non-Federal mines and new Federal leases in the West and from other coal-producing regions of the country and because overall demand for coal may not grow sufficiently during the next decade to support this level of production from Federal mines.

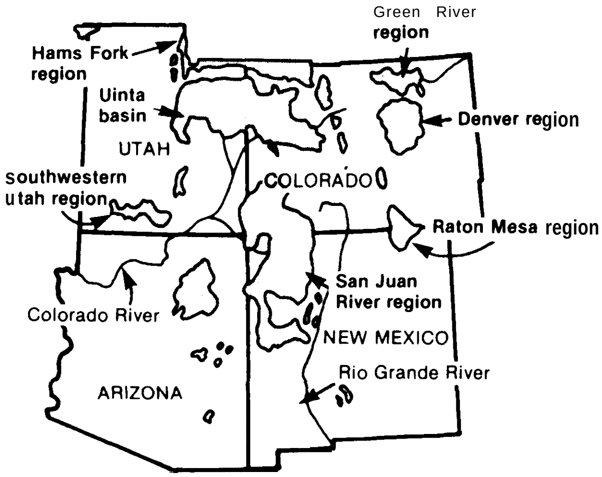
During the 1990's, demand for coal in general and Western and Federal coal in particular might grow rapidly, particularly if coal-based synfuels and exports to foreign countries become important.

Development Potential and Production Prospects of Federal Coal Leases in Colorado, New Mexico, and Utah

Overview

Colorado, New Mexico, and Utah comprise what is referred to in this report as the Southern Rocky Mountain region. * This three-State area embraces five major Western coal-producing regions—the Uinta region, the San Juan River region, the Denver-Raton Mesa region, Southwestern Utah, and the Colorado portion of the Green River-Hams Fork region (see fig, 25). The 360 Federal coal leases in these States cover over 451,000 acres and contain over 5.9 billion tons of recoverable coal reserves (see table 34), These States have 64 percent of the total Federal leases, over 55 percent of the acreage under lease, and over 35 percent of the reserves under lease. Roughly one-third of the leases in the Southern Rockies are in approved mine plans, another third are in proposed mine plans, and the remaining third are undeveloped. Total production from Federal coal reserves in Colorado, New Mexico, and Utah was 20 million tons in 1979 or about 45 percent of the total production of 45 million tons in the three States. In 1980, production from Federal reserves was 24.4 million tons out of total production in the Southern Rocky Mountain area of over 49 million tons. These three States contributed about 33 percent of the total production from all Federal leases in 1979 and 35 percent of the 1980 production.

Figure 25.–Coal Regions in the Southern Rocky Mountain States



SOURCE Office of Technology Assessment

Summary of Production Potential and Planned Capacity

Production from mines with existing Federal leases in the Southern Rocky Moun-

*The Southern Rocky Mountain and the Northern Great Plains regions-as used in this report-should not be confused with the Northern Great Plains and Rocky Mountain coal provinces. The Rocky Mountain coal province is a geologic and physiographic designation that includes coalfields west of the continental divide and the Denver basin and Raton Mesa coal regions of Colorado and New Mexico. The Rocky Mountain coal province runs from the Big Horn basin of northwestern Wyoming to coalfields in southern New Mexico. The Great Plains coal province includes the Powder River basin and Fort Union region of Wyoming, Montana, and North Dakota. Geologic province designations are made on the basis of the geologic characteristics and age of the coal deposits. (Arizona, which is also part of the Rocky Mountain coal province, has little Federal coalland and no Federal coal leases.)

Table 34.— Federal Coal Leases in Colorado, New Mexico, and Utah

State/region	Total number of leases	Total number of plans or lease blocks	Total Federal acres	Total recoverable reserves (millions of tons)
Colorado				
Green River	57	34	53,254	1,363
Uinta	63	27	69,793	803
San Juan .,	1	1	160	1,6
Denver-Raton Mesa	6	4	3,686	66
Total	127	66-	126,893	2,234
New Mexico				
San Juan . .	26	12	44,560	447
Denver-Raton Mesa	3	3	200	0.5
Total	29	15	44,760	447
Utah				
Uinta, ...	108	42	128,930	1,503
Southwestern Utah	96	14	150,566	1,750
Total . .	204	56	279,496	3,253
Regional total .,	360	137	451,149	5,934

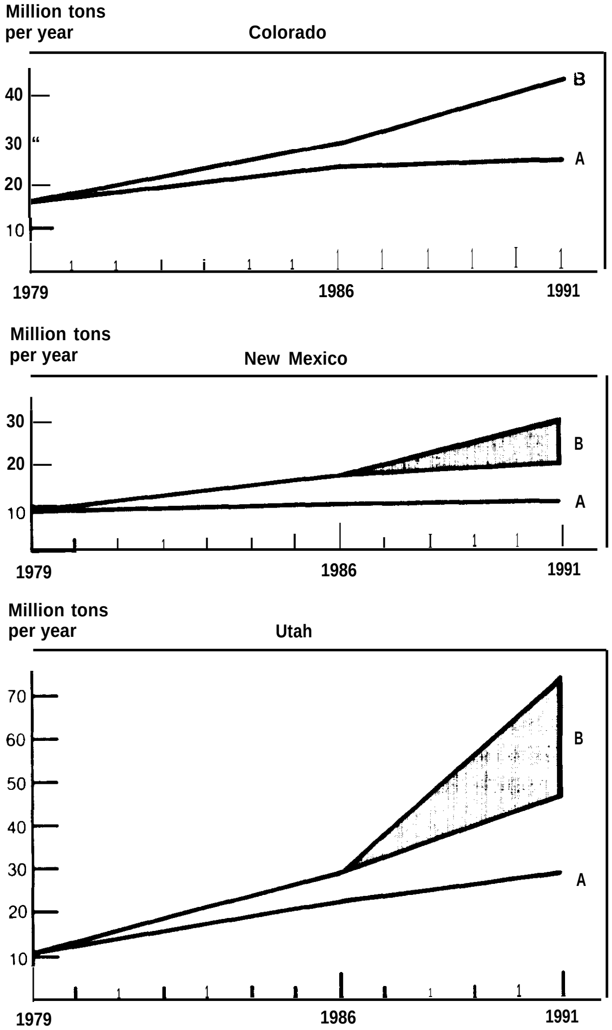
NOTE Sums of acreage and reserves may not add to totals because of Independent rounding

SOURCE Off Ice of Technology Assessment

tain area is expected to rise substantially in the next decade as existing and planned mines reach full operation and new mines are opened on undeveloped leases. By 1986, according to current mine plan schedules, production from Federal mines could reach over 76 million tons-more than double 1979 production. By 1991, depending on the rate at which Federal leases are developed, production from Federal mines could total between 110 million and **146** million tons—potentially doubling the **1986** output and at least tripling the 1979 level. Figure 26 shows projected increases in production from Federal leases in Colorado, New Mexico, and Utah. The percentage of total regional production coming from Federal leases will also increase significantly from about 44 percent in 1980 to over 60 percent by 1991.

Most of the projected increases in production will come from new mines that will not achieve their full design capacity until the mid-l990's. The estimated 1991 production range of 110 million to 146 million tons is less than the total maximum annual capacity of over **200** million tons per year that could be supported by mines on existing Federal leases in the mid-l990"s, In the late **1990's**

Figure 26.— Potential Production Capacity of All Mines With Federal Leases in Colorado, New Mexico, and Utah



A. Lessees' planned annual production capacity for Federal mines in currently approved mine plans only
B. The sum of A, above, plus estimates of production capacity for Federal mines in pending mine plans and for presently undeveloped Federal leases

SOURCE Office of Technology Assessment

however, as many of the mines that are now operating exhaust their reserves, the total capacity supported by existing leases will begin to decline slowly.

The maximum annual capacity of the 35 mines with 113 Federal leases that currently have approved mine plans is about 74 million tons per year at full operation, Proposed mine plans have been submitted for 25 new mines with 108 Federal leases that would add over 71 million tons of annual capacity. (When the capacity of existing mines is referred to, it means capacity at full-scale operation, not current installed capacity.) Nearly half of the existing and planned capacity (about 64 million tons per year) is in underground mines in the Uinta region of Utah and Colorado. About 40 percent of the capacity (nearly 30 million tons) in pending mine plans is from proposed mines in Southwestern Utah.

Production in the Southern Rockies will generally be less than capacity until the mid-1990's, however, overcapacity is not expected to be as significant in this region as in the Northern Great Plains. Many of the larger mines in the Southern Rockies have opened in the past 4 years and are still under construction. These new mines will not reach full commercial operation for several more years. Other existing and proposed mines have scheduled production to fuel new electric powerplants when they begin operations. Several of the mines with pending mine plans will not begin producing until after 1986 and will reach full-scale production by the early 1990's.

Many of the 139 currently undeveloped leases could, according to OTA's analysis, support new mines and at least 13 undeveloped lease blocks with 27 leases are already in mine plan preparation stages. By 1986, few undeveloped leases will be producing. By 1991, they could contribute between 17 million and 32 million tons of production. If all of the undeveloped leases with favorable or uncertain development potential go into production, they could add 34 million to 57 million tons of new annual capacity. Most of this new capacity (between 23 million and 45 million tons per year) would come from mines in Utah and in the Green River region of Colorado. Besides market uncertainties, the major difficulty affecting production from undeveloped leases is construction of coal transportation systems in Utah and New Mexico.

Quality of Coal Under Lease

The Southern Rocky Mountain States have a wide variety of coal resources and mining conditions. The coal quality ranges from lignite deposits in the Denver basin to high-grade metallurgical bituminous coals in the Uinta region of Colorado and Utah and in the Raton Mesa fields of New Mexico and Colorado. The three-State region has supported an active coal mining industry for over a century. Mines currently in operation in the region range from small underground mines producing several thousand tons per year to large surface mines producing over 5 million tons per year. Several of the underground mining operations will reach production levels of 4 million to 6 million tons per year by the early 1990's, and several new surface and underground mines are planned that will achieve annual production levels in excess of 10 million tons per year.

Generally the active mining areas have good quality minable coal reserves, however, they do not have the extensive shallow, very thick seams that give a cost advantage to surface mines in areas of the Powder River basin. The higher heat content of Southern Rocky Mountain coals, however, partially offsets the lower mining costs in the Northern Great Plains, especially, when coals are shipped great distances. In some fields in the Southern Rockies, the location and quality of the coals make them strong competitors for coal from other areas. In northwest Colorado, for example, minable surface reserves can reach an aggregate seam thickness of 60 ft with overburden depths between zero and 400 ft.

Underground mining conditions in the coalfields vary, but generally, these regions are characterized by thick minable seams of 5 to 12 ft. Some underground seams are 25 ft thick or more, however, current mining methods have limited recovery to only 12 to 14 ft of coal. Newer techniques, such as multiple-lift longwall, promise improvements in recovery rates; but even with recovery rates of only 40 percent in some underground mines, the mining conditions and seam thicknesses are often more favorable than those encountered in some Eastern and Midwestern coalfields.

Most of the reserves under lease in the Southern Rocky Mountain region are subbituminous to bituminous in rank. They include high-quality coal reserves with heat contents ranging from 9,000 to over 14,000 Btu/lb. Most have relatively low sulfur contents of 1.5 percent or less, making them suitable for compliance quality coal. * The ash content also averages less than 15 percent. Some coals in the San Juan basin of New Mexico and the Denver basin of Colorado are an exception with relatively lower Btu values, (as low as 7,800 Btu/lb in the San Juan basin) and relatively higher average ash contents of up to 29 percent at the mine. These coals are nevertheless considered marketable for their area because the coal can be washed to reduce ash contents to between 16 to 17 percent.

Table 35 shows the rank of coal under lease in each of the major coal production regions in the three States and the amount of recoverable reserves of each type by mine plan status. Federal lease reserves in approved mine plans contain about 1.2 billion tons of bituminous coal and 0.3 billion tons of subbituminous coal. There are about 1.4 billion tons of bituminous reserves and about 0.5 billion tons of subbituminous reserves on leases in pending mine plans. Undeveloped Federal lease reserves include over 2 billion tons of bituminous coal and nearly 0.3 billion tons of subbituminous coal. Only about 49 million tons of leased reserves in the three States are classified as lignite.

*As discussed in chs. **4** and **5, one strategy** of complying with Clean Air Act requirements before the 1977 amendments and implementing regulations was to blend low-sulfur "compliance" coals with higher sulfur local coals so that average sulfur content would be low enough so that pollution control equipment costs were minimized while meeting Clean Air Act requirements. The 1977 changes requiring sulfur reduction for all coals removed what had been an advantage for Western coals.

Table 35.—Rank of Coal Under Lease in the Southern Rocky Mountain Region Reserves and Mine Plan Status (all reserves in millions of tons)

	Approved mine plans					Pending mine plans					Leases without mine plans						
	Bituminous			Sub-bituminous		Bituminous			Sub. bituminous		Bituminous			Sub-bituminous			Lignite
State/region	HvAb	HvBb	HvCb	SbA	Sbc	HvAb	HvBb	HvCb	SbA	SbC	HvAb	HvBb	HvCb	SbA	SbB	SbC	Lignite A
Colorado																	
Green River			**146**	**160**				**29**				**185**	**487**	**43**	**88**	**18**	
Uinta	**63**	**164**	**8**			**92**	**165**	**110**			1	**31**	**7**		**130**		
San **Juan**		2															
Denver-Raton Mesa											17	01					49
Total	63	166	154	160		92	165	139			18	217	494	43	218	18	49
New *Mexico*																	
San Juan			**34**		**135**			**38**	**56**	**89**		**94**		1			
Denver-Raton Mesa											0.1		04				
Total			**34**		**135**			**38**	**56**	**89**	01	**94**	04	1			
Utah																	
Uinta	2	676	114			16	141	108			83	359	0.3				
Southwestern Utah								671	335		43	02	698	3	0 3		
Total	2	676	114			16	141	778	335		125	359	698	3	0 3		

Total reserves by rank may vary slightly from total lease reserves in other tables because of differences in the sources of coal quality data Column totals may not add due to Independent rounding

NOTE Calorific values by rank in Btu per pound based on a moist, mineral matter. free basis, are as follows
(HvAb) high volatile A bituminous > 14,000 Btu/lb (SbA) sub.bituminous A 10,500-11,500 Btu/lb Lignite A 6,300.8,300 Btu/lb
(HvBb) high volatile B bituminous 13,000-14,000 Btu/lb (SbB) sub-bituminous B 9,500-10,500 Btu/lb
(HvCb) high volatile C bituminous 11,500-13,000 Btu/lb (Sbc) sub.bituminous C 8,300-9,500 Btu/lb

See ch. 4 for di!scussion of coal rank.

SOURCE Off Ice of Technology Assessment, Mine Plan Data and Department of Interior Automated Coal Lease Data System

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Production and Consumption of Coal From Colorado, New Mexico, and Utah

The Rocky Mountain region coals serve many markets. Most of the coal produced in the three States is consumed in the region or in the west coast markets (see fig. 20, ch. 5.) Under existing long-term contracts, however, a significant amount is shipped to the South and Midwest. Coal from Utah is shipped to Mississippi utilities, and coal from Colorado is burned by Indiana utilities. Coals from Colorado and Utah have been sold under contract for export to consumers in Korea and Japan.

Colorado, New Mexico, and Utah also have deposits of metallurgical coal. Although some of this coal is not of as premium a quality as some metallurgical coals in the East, these Western reserves have supplied the Western steel industry for decades and also show some promise for expanding export markets. Over the next decade, production of metallurgical coal in the Rocky Mountain States is expected to continue at current annual levels of about 3 million tons a year because of conditions in the domestic steel industry.

In the past decade, Colorado, Utah, and New Mexico have seen an increase in coal production and planned mining activities, Many Federal leases have recently gone into production and new mine plans have been proposed for others. Table 36 shows the increases in total and Federal production in these States for selected years since 1972, Federal coal production in these States has risen from 4.6 million tons in 1972 to over 24 million tons in 1980, while total annual production for the region has risen from 19.4 million tons in 1972 to approximately 49 million tons in 1980. Federal leases thus have contributed an even larger share of total production, growing from about 25 percent in 1972 to approximately 50 percent in 1980. The Federal share of total regional production is expected to increase substantially over the next decade. Coal producers in these three States have shared in the generally increased level of coal development activities in the West and hold the optimistic expectation that the coal production from these States will be competitive and capture its share of the expanding market.

In 1979, Federal mines in the Southern Rockies produced 34.7 million tons of coal, with about 20 million tons mined from Federal reserves. If all existing and proposed mines on Federal leases are developed and produce at their expected rates, the 1986 production from mines with Federal leases could more than double the 1979 levels (see table 37). By 1991, production from Federal mines could be more than three times the 1979 level. The increases in production would be most dramatic in Utah, rising from 10 million tons in 1979 to as much as 74 million tons in 1991. In general, the OTA potential production from Federal mines compares favorably with the State task force production estimates and with the Department of Energy's (DOE) final 1985 and 1990 production goals, previously

Table 36.—Total and Federal Production in Colorado, New Mexico, and Utah: Selected Years, 1972-80 (millions of tons)

	1972		1976		1977		1978		1979		1980	
	Total	Federal	Total	Federal	Total	Federal	Total	Federal	Total	Federal	Total	Federal
Colorado	5.5	2.4	9.4	1.6	12.0	4.0	13.8	5.7	18,1	7.7	19,5	9.4
New Mexico	8.2	0.2	10.0	1.2	11.1	2.3	12,6	4,3	15.1	5.4	16,5	6.3
Utah	5.7	2.0	799	4.4	8.6	5.8	9.1	5.3	11.8	6.9	13,1	8.7

SOURCES U.S Department of the Interior, *Annual Federal* Coal Management *Reports, Fiscal Years 1979 and 1980*
U S **Geological Survey,** *Federal* **and** *Indian Lands Coal, Phosphate,* Potash, *Sodiurn, and Other Minerals Production,* Royalty Income *and* Related *Statistics* Calendar year 1960, June 1981
Bureau of Land Management, *Public Land Statistics 1976.*
U.S. Department of the Interior, Final *Environmenal Statement Proposed Federal Coal Leasing Program (1975)*
McGraw Hill, *Keystone* Coal *Indusfry Manual 1977.*
U.S. Department of Energy, Energy Information Administration, Coal *Production 1980* **(preliminary), June 1981**

Table 37.—Potential Production From Federal Coal Leases
(all production in million tons per year)

State/region	Production in 1979	Potential production from mines with Federal leases: 1986 — From leases in approved mine plans[a]	1986 — From leases in pending mine plans[a]	1986 — From leases without mine plans[b]	1986 — Total	1991 — From leases in approved mine plans[a]	1991 — From leases in pending mine plans[a]	1991 — From leases without mine plans[b]	1991 — Total
Colorado									
Green River ...	11.2	19.0	1.3	0.6	20.9	20.0	1.8	6.4	28.1
Uinta	4.7	5.6	2.8	0	8.4	5.8	7.4	1.3	14.5
San Juan	0.08	0.07	0	0	0.07	0	0	0	0
Denver-Raton Mesa	0	0	0	0		0	0	0.5	0.5
Total ., ., ...	16,0	24.7	4.1	0.6	29.4	25.8	9.3	8.2	43.1
New Mexico									
San Juan	8.4	10.0	6.6	0.2	16.8	10,5	7.5-10.5	1.7-8.0	19.7 -29.0
Denver-Raton Mesa ., . .	0	0	0	0	0	0	0	0	0
Total . . . . . .,	8.4	10.0	6.6	0.2	16.8	10.5	7.5-10.5	1.7-8.0	19.7 -29.0
Utah									
Uinta	10.4	24	5.6	0	29.6	29.0	11.3	7.0-8.6	47.3-48.9
Southwestern Utah	0	0	0.6	0	0.6	0	0-18.0	0-7.4	0-25.4
Total ., ...	10.4	24	6.2	0	30.2	29.0	11.3-29.3	7.0-? 6.0	47.3-74.3
Grand total	34.7	58.7	16,9	0.8	76.4	65.3	28.1 -49.1	16.8 -32.1	110.1 -146.4

[a]For leases in mine plans, with few exceptions, the lessees' planned production is used.
[b]For leases with no mine plans and favorable or uncertain development potential, OTA estimates are used, Ranges in production reflect uncertainties In construction schedules and final mine capacity

Columns may not add to totals due to independent rounding

SOURCE Office of Technology Assessment

described in chapter 5 of this report (see table 31).

In 1986, production from all mines on Federal leases, including currently undeveloped leases, could reach 76.4 million tons with about 29 million tons coming from Colorado mines, 17 million tons from New Mexico, and over 29 million tons from Utah. Estimated production from mines on Federal leases in the Colorado portion of the Green River-Hams Fork region is 20.9 million tons in 1986 with about 15.7 million tons from surface mines. Total production from Federal mines in the Uinta region in 1986 is expected to be about 36 million tons (8.4 million tons in Colorado and 29.6 million tons in Utah). Almost all of this production will come from underground mines. Production from mines with Federal leases in the San Juan region is estimated to reach 16.8 million tons in 1986 with most of it coming from large surface mines in New Mexico,

For both Colorado and New Mexico, the DOE 1985 production goals are higher than the potential production from Federal leases, however, the difference is in large part offset by production from existing and planned non-Federal mines and from new mines on Federal PRLAs. In Utah, OTA's potential production from Federal mines of 30 million tons matches the DOE medium production goal, but both estimates are higher than the estimate of 15 million to 18 million tons used by the OTA Utah task force.

For 1991, production from mines with Federal leases is projected to increase to between 110 million and 146 million tons depending on the rate of mine construction. Federal mines in Colorado would account for 43 million tons, New Mexico mines for up to 30 million tons and production from Utah mines would add between 47 million to 74 million tons. About 28 million tons could come from Federal mines in the Green River region. Between 59 million and 61 million tons could be produced from Federal mines in the Uinta region (14.5 million tons in Colorado and 44.8 million to 46.4 million tons in Utah). Between 19.7 million and 29 million tons is expected to be produced from Federal mines in the San

Juan region in New Mexico. Production from Federal leases in Southwestern Utah is uncertain and ranges from no production at all to as high as 25 million tons by 1991.

The 1990 DOE production goals for Colorado range from a low of 28 million tons to a high of 43 million tons; 35 million tons is the midlevel goal. (These goals were reduced slightly from the preliminary DOE goals published in August 1980.) Potential production of 37 million to 43 million tons from Federal mines and undeveloped leases could meet or exceed the DOE goals and the State task force 1991 minimum production estimate of 32 million to 38 million tons. Even though non-Federal mines are expected to contribute a smaller relative share of State production by the late 1980's, the large production capacity of existing Federal leases is apparent. However, at least a portion of this capacity could be used to replace existing mines that will shut down in the mid-1990's. Potential Federal mine production of 47 million to 74 million tons in Utah in 1991 could also exceed the DOE high production goal of 63 million tons and the State task force estimate of 30 million tons. However, when the likelihood of little, if any, production from Southwestern Utah is considered, the lower estimate of 47 million tons in 1991 is comparable to the DOE medium goal of 49 million tons. Both the DOE 1990 New Mexico production goals (56 million to 67 million tons) and the OTA task force 1991 maximum production estimate of 72 million tons are substantially higher than Federal mine production of 20 million to 29 million tons. When planned production from Indian and non-Federal mines is added to Federal mine production, the total is around 67 million tons, the DOE goal, but still less than the OTA task force estimate. Thus, while there is a substantial variety in estimates of coal demand and production for the Southern Rocky Mountain States, in most cases, OTA's estimated potential production from Federal mines falls within the ranges of production that would be absorbed under the various forecasts.

By the early 1990's, several currently operating mines on Federal leases will deplete their existing lease reserves. Replacement capacity for at least three of these mines will come from new mines on other existing Federal leases. Replacement capacity amounts to between 5 million and 10 million tons of total new annual production capacity.

OTA's production estimates include some uncertainties that are reflected as ranges of potential production and capacity. If all leases meet current mine plan schedules and demand for coal from these States increases as expected, production from Federal mines could reach 110 million tons in 1991. Production of an additional 36 million tons of coal in 1991 is possible, but subject to large uncertainties as a result of factors that could delay or prevent development. About 10 million tons of estimated 1991 output comes from existing or proposed captive mines that may not reach planned full production levels because of changes in internal coal requirements or production schedules. Between 4 million and 8 million tons of 1991 production could be used in proposed synthetic fuel projects. However, according to the lessees, delays in these projects are not expected to affect planned production in 1991 since the coal produced could be used to meet existing contracts.

The greatest uncertainty involves the estimated 25 million tons of production, and 36 million to 45 million tons of annual capacity from mines in Southwestern Utah. Except for the Alton Mine, none of the existing leases there have even tentative commitments for potential production. Furthermore, the Alton and Kaiparowits Plateau fields are not connected to existing transportation networks. A slurry system and rail line have been proposed to link these fields to potential markets, primarily in Nevada and California. However, according to most estimates, at least 30 million tons of annual coal production would be needed to support construction of the needed transportation system. OTA's analysis indicates that Federal leases on the Kaiparowits Plateau could support that level of production, however, it is unlikely that the lessees would begin producing without assurances that the transportation system would be built. Mine-mouth powerplants that were once proposed for Southern Utah, have been abandoned because of high capital costs and water availability and air pollution problems. The Alton Mine and slurry project is opposed by environmental groups because of potential impacts on Bryce Canyon and Zion National Parks and on regional water supplies and air quality.

The rate of development for about 10 million tons of capacity in the central San Juan basin of New Mexico is also in question because of delays in the original construction schedule and final right-of-way approvals for the proposed Star Lake Railroad. In addition, two proposed mines there are linked to pending PRLAs and sustaining full production capacity depends on the availability of PRLA reserves. Several of the lessees could, however, begin small-scale production on existing leases before 1986 in order to meet diligence requirements and could delay expansion until the rail line is completed. Thus, delays are not expected to affect lease development except in the rate of construction and production.

The factors affecting development and production from Federal leases in Colorado, New Mexico, and Utah are discussed in more detail in the State appendixes to this report and in the OTA task force reports.

Development Status of Federal Coal Leases in the Southern Rocky Mountain Region

Over **60** percent of the 360 coal leases in the Southern Rocky Mountain region were covered by approved or pending mine plans as of September 30, 1980. About 30 percent, 113 leases, are part of 35 operating mines with approved mining plans. During fiscal year 1980, coal was actually produced from 57 of these leases in approved mine plans. (The number of leases in approved mine plans that are actively being mined varies according to the lessees' production schedules and mine configurations.) Another 108 leases are included in 25 proposed new mines for which mine plans have been submitted to DOI. The remaining 139 leases, 38 percent of the leases in the region, have not yet reached the mine plan stage of development. The 139 undeveloped leases are divided into 77 different blocks of contiguous leases in common ownership. (Table 38 summarizes the acreage and reserves under lease by mine plan status.)

While many existing leases are in historically active mining areas, some are located in areas that have not been mined extensively. Two such areas—the southern San Juan basin and Southwestern Utah—are largely rural and have supported little past coal mining activity. Proposed large-scale coal development in these two fields with substantially untapped coal resources raises potentially difficult conflicts with other resource values and land uses. Several of the active mining areas face major expansions of coal mining at the same time that they are already being affected by development of other energy sources—oil shale, oil and gas, uranium, and tar sands. If all these development activities proceed, they could change the predominantly rural character and economic base of these regions which primarily have depended on mining, agricultural, recreational, and nonindustrial activities.

Federal coal production in the Southern Rocky Mountain region has more than quadrupled in the past decade and it will continue to grow during the 1980's as new mines open and existing mines expand capacity. By 1991 according to OTA's analysis, total production from mines operating on existing Federal leases in the region could reach as much as 146 million tons. Total mine capacity could eventually reach more than 216 million tons per year in the mid-1990's if all planned mines and leases with favorable and uncertain development prospects go into production.

Table 38.—Acreage and Reserves Under Lease by Development Status

	Approved mine plans				Pending mine plans				No mine plans			
State/BLM *coal region*	Number of leases	Number of plans	Acres	Recoverable reserves (millions of tons)	Number of leases	Number of plans	Acres	Recoverable reserves (millions of tons)	Number of leases	Number of blocks	Acres	Recoverable reserves (millions of tons)
Colorado												
Green River	31	10	25,687	519	3[a]	3	3,150[a]	28[a]	23	21	24,417	816
Uinta	22[b]	8	16,239[b]	203[b]	18[c]	8	34,704[c]	427[c]	23	11	18,850	173
San Juan	1	1	160	1.6	—	—	—	—	—	—	—	—
Denver-Raton Mesa	—	—	—	—	—	—	—	—	6	4	3,686	66
Total	54	19	42,086	724	21	11	37,855	455	52	36	46,953	1,055
New Mexico												
San Juan	9[d]	2	18,828	169[d]	9	3	21,098	183	8	7	4,634	95
Denver-Raton Mesa	0	0	0	0	0	0	0	0	3	3	200	0.5
Total	9	2	18,828	169	9	3	21,098	183	11	10	4,834	95
Utah												
Uinta	50	14	55,540	792	14[e]	8	25,711[e]	264[e]	44	20	47,679	447
Southwestern Utah	0	—	—	—	64	3	93,029	1,006	32	11	57,537	744
Total	50	14	55,540	792	78	11	118,740	1,270	76	31	105,215	1,191

NOTE: Sums of acreage and reserves columns may not add to totals because of Independent rounding

[a]Lease total does not include one lease in pending Trout Creek underground mine plan, which is also part of approved Edna surface mine, acreage and reserves totals have been adjusted 10 avoid double counting

[b]Approved mine plan lease and acreage totals exclude one lease in the approved Bear Mine, which is included in the larger, proposed Mt. Gunnison Mine to avoid double counting.

[c]Pending mine plan lease, acreage and reserve totals exclude one lease in proposed Blue Ribbon Mine located on a portion of U.S. Steel's Somerset Mine leases that have an approved plan, totals have been adjusted to avoid double counting.

[d]Approved mine plan lease, acreage and reserve totals also include one lease issued in 1980 for the San Juan Underground Mine Extension and one small lease Included in a minor modification to the San Juan surface mine.

[e]Total does not include three leases that are part of the pending O'Connor mine plan and which are also covered in part by the approved Belina and skyline mine plans, totals have been adjusted to avoid double counting

SOURCE: Off Ice of Technology Assessment

Leases With Approved Mine Plans

There are 113 leases in 35 active mines with approved mine plans in the Southern Rocky Mountain region. They cover a total of over 116,000 acres of Federal land and contain more than 1.6 billion tons of recoverable Federal coal reserves. Nine mines are surface operations (seven in Colorado, two in New Mexico) and 26 are underground mines (12 in Colorado, 14 in Utah). Over the next decade, two of the active surface mine operations are planning to shift to underground operations to recover deeper reserves (one in Colorado, one in New Mexico). Table 39 summarizes the acreage and reserves for mines with Federal leases in Colorado, New Mexico, and Utah. Table 40 shows the total capacity and estimated 1979, 1986 and 1991 production for mines with approved mine plans on Federal leases.

The 26 underground mines range in size from two small mines producing less than 100,000 tons per year (one in Colorado, one in Utah) to large mine complexes producing over 1 million tons annually. Three of the existing underground mines propose to expand annual production capacity to 5 million tons per year or more by 1986. The nine active surface mines on Federal leases range in size from one small operation producing just over 100,000 tons annually to several large surface mines producing over 5 million tons per year. Most of the surface mines produce between 1 million and 3 million tons annually. Surface mining activity on existing leases is currently limited to the Green River region of

Table 39.—Summary of Mine Plan and Federal Lease Acreage and Recoverable Reserves: Approved Mine Plans, Sept. 30, 1980 (all reserves shown in millions of tons)

State/region	Number of leases	Number of mine plans	Total mine plan acres	Total Federal mine plan acres	Total Federal lease acres	Total mine plan reserves			Total Federal lease reserves		
						Under-ground	Sur-face	Total	Under-ground	Sur-face	Total
Colorado											
Green River	31	10	40,300	25,687	25,687	113	303	416	199	320	519
Uinta	22	8	24,104a	16,239a	16,239a	208	0	208	203	0	203
San Juan	1 1	1	160	160	160	0.7	0	0.7	1.6	0	1.6
Denver-Raton Mesa	—	—	—	—	—	—	—	—	—	—	—
Total	54	19	64,564	42,086	42,086	322	303	625	404	320	724
New Mexico											
San Juan	9	2	13,622[b]	14,972[b]	18,828	0	194	194	0	169	169
Denver-Raton Mesa	—	—	—	—	—	—	—	—	—	—	—
Total	9	2	13,622	14,972	18,828	0	194	194	0	169	169
Utah											
Uinta	50	14	85,260[c]	54,523[c]	55,540[c]	630	0	630	792[c]	O	792[c]
Southwestern Utah	—	—	—	—	—	—	—	—	—	—	—
Total	50	14	85,260	54,523	55,540	630	0	630	792	0	792

[a]Total excludes acreage in approved Bear Mine that is also included in pending Mt. Gunnison mine Plan.
[b]Total mine plan acreage and Federal mine plan acreage exclude 3,856 acres in San Juan Underground Mine expansion not approved as of Sept. 30, 1960
[c]All totals have been adjusted to avoid double Counting of lease acres and reserves Included in the Belina and Skyline approved mine plans and the pending O'Connor mine plan

SOURCE Off Ice of Technology Assessment, mine plan review

northwest Colorado and to the San Juan basin of New Mexico, although two surface mine operations are proposed for Federal leases in Utah.

Total capacity of the active mines with Federal leases is 74.3 million tons per year at full production. The surface mines in Colorado and New Mexico account for about 26 million tons of annual capacity. The remaining 48 million tons of capacity is in underground mines. Many of the active mines have been opened within the last 5 years and will not produce at full capacity until about 1986.

Most of the approved mining operations include both Federal and non-Federal coal reserves. Total estimated production from these mines in 1979 was 34.7 million tons. About 20 million tons of this production came from the more than 55 Federal leases in approved mine plans that were actually mined. About 20 million tons of the total 1979 Federal mine production came from surface mines and 14 million tons was from underground mines.

By 1986, production from mines with approved mine plans could total 58.7 million tons. About 26 million tons of this will come from surface mines. By 1991 production from currently active mines is projected to be 65.3 million tons. Over the next decade at least two of the mines with approved plans are expected to exhaust their reserves and the operators will shift to proposed new mines on other Federal leases.

Colorado.—There are 19 mines with approved mine plans operating on Federal leases in Colorado. The 54 leases in these mines cover over 42,000 acres and contain an estimated 724 million tons of recoverable reserves. Seven of the approved operations are surface mines located in the Green River region of northwest Colorado. The remaining 12 mines are underground mines. Three of the underground mines are in the Green River region, eight are found in the Uinta region and one in the San Juan River region. There are no active mines on Federal leases in the Denver-Raton Mesa region of Colorado.

Table 40.—Mine Capacity and Projected Production: Leases in Approved Mine Plans: Colorado, New Mexico, and Utah, Sept. 30, 1980 (capacity and production in millions of tons)

				1979	1986		1991	
State/basin	Number of mine plans with Federal leases	Number of Federal leases in these plans	Maximum annual capacity of all proposed mines	Actual production from mines with Federal leases	Maximum mine capacity of producing mines	Projected production from mines with Federal leases	Maximum mine capacity of producing mines	Projected production from mines with Federal leases
Colorado								
Green River	10	31	23.6	11.2	20.6[a]	19.0	20.5[b]	19.9
Uinta	8	22	8.0	4.7	7.7[c]	5.6	6.5[d]	5.8
San Juan	1	1	0.07	0.08	0.07	0.07	0[e]	0
Denver-Raton Mesa .	0	0	0	0	0	0	0	0
Total	19	54	31.6	16.0	28.4	24.7	27.0	25.8
New Mexico								
San Juan	2	9	10.5[f]	8.4	10.5	10.0	10.5	10.5
Denver-Raton Mesa .	0	0	—	—	—	—	—	—
Total	2	9	10.5	8.4	10.5	10.0	10.5	10.5
Utah								
Uinta	14	50	32.2	10.4	32.2	24.0	32.1[g]	29.0
Southwestern Utah .	0	0	0	0	0	0	0	0
Total	14	50	32.2	10.4	32.2	24.0	32.1	29.0
Regional total.	35	113	74.3	35.4	71.1	58.7	69.6	65.3

[a]Empire Energy Eagle #5 and #9 Mines exhaust existing lease reserves; possibility Of extending mine life with new lease reserves not known.
[b]canadian Strip mine exhausts existing lease reserves; additional new lease reserves have been requested.
[c]Bear Mine shuts down in early 1980's, production from lease continues as part of proposed Mt Gunnison Mine.
[d]Roadside Mine exhausts existing lease reserves according to mine plan.
[e]Kng Coal Mine shuts down because existing lease reserves exhausted.
[f]Capacity excludes 2 million tons of replacement capacity from the San Juan underground mine, which will open in early 1980's, to maintain production at San Juan Mine complex at 5.5 million tons annually.
[g]Trail Mountain Mine exhausts existing lease reserves according to mine plan; additional new lease reserves have been requested.

Maximum capacity means the highest annual production from a mine operating at its full designed capacity level and not the installed capacity in place in 1988 to 1991. Actual installed capacity for most mines in the Southern Rocky Mountains will be at or near the projected production levels,
Production estimates based on lessees' mine plan schedules,

SOURCE: Office of Technology Assessment.

At full operation, the total production capacity of the active mines on Federal leases is 31.6 million tons per year. These mines include large surface mines producing over 3.4 million tons annually, medium to large underground mines yielding from 200,000 to over 1 million tons annually, and several small operations serving local or spot markets. Several of the underground mines are expanding their capacity by constructing new portals that will allow mining of several overlying seams at the same time. These enlarged underground mines will be capable of producing over 4 million tons annually—thus matching the capacity of large surface mines in the same area. By the early 1990's, several large surface mines in the Green River area are expected to exhaust their current mine plan reserves and will have to either shut down or shift to underground recovery if additional strip reserves are not available. At least one underground mine will require additional unleased Federal reserves to maintain the planned level of production.

Total 1979 production from the 19 mines with Federal leases in Colorado was more than 16 million tons; 7.7 million tons was mined from 39 of the Federal leases. According to current mine plan projections, production from currently active mines on Federal leases is expected to reach 24.7 million tons by 1986 and by 1991 their total output will rise slightly to about 25.8 million tons. The

Federal leases in approved mine plans are discussed more fully in the Colorado appendix.

New **Mexico.** —The two currently operating mines on Federal lands in New Mexico include nine Federal leases with over 18,000 acres and 169 million tons of Federal reserves. Both mines are located in the San Juan basin in northwestern New Mexico. The McKinley Mine, near Gallup operates on Federal, Navajo and private lands; the San Juan Mine near Farmington operates mostly on Federal land. The total annual production capacity of these two surface mines is currently 10.5 million tons. The San Juan Mine will replace about 2 million tons of surface capacity with underground capacity as it moves to deeper seams.

In 1979, the two mines produced a total of 8.4 million tons with 5.4 million tons coming from Federal reserves. According to current mine plans and information from lessees, total production will increase to 10 million tons by 1986. Capacity and production from the two mines are projected to remain at around 10 million tons per year through 1991. Production from both mines is used primarily at powerplants in the Southwest. See the New Mexico appendix for additional information on these mines.

Utah.—There are currently 14 active underground mines with Federal coal leases in the Uinta coal region in central Utah. These 14 approved mine plans include 50 leases covering a total of more than 55,000 leased acres and containing about 792 million tons of recoverable coal reserves. At full operation, the total capacity for these mines will be 32.2 million tons per year, or roughly three times greater than the 1979 production levels.

Total coal production in Utah in 1979 was 11.8 million tons. About 10.4 million tons of this was produced by the mines with Federal leases, with 6.9 million tons mined from Federal reserves. The Utah State Geological Survey estimates that up to 2 million tons of coal were stockpiled by several Utah mines in 1979 because of low demand. This overcapacity is expected to be short-lived. With the opening of the new Emery and Intermountain Power Project electric generating stations, in-State use will expand significantly. Spot market sales and long-term contracts for exports to Japan and Korea are being negotiated. According to several coal operators in the region, all current excess capacity in Utah was under contract by early 1981.

By **1986,** production from mines with approved plans on Federal leases in Utah is expected to rise to about 24 million tons. Two of the currently producing mines are scheduled to be depleted in the early 1990's. However, this loss in capacity will be offset as newer operations reach full production levels in the late 1980's. By 1991, total production from the currently approved mining operations is projected to increase to about 29 million tons. A significant portion of this total is captive production for steel and utility companies. See the Utah appendix for additional information on active mines on Federal leases in Utah.

Leases in Pending Mine Plans

As of September 30, 1980, 25 mine plans with 108 Federal leases were under review by DOI. These new mines include a total of 108 Federal leases with over 177,000 acres and 1.9 billion tons of recoverable reserves. Most of the proposed mines include both Federal and non-Federal coal reserves. The mine plans cover more than 221,000 acres with Federal leased acreage making up about 75 percent of the total. The 25 pending mine plans vary widely in completeness and sophistication, ranging from multivolume, technically complete proposals in the final stages of permit review, to more general "conceptual" descriptions of the lessee's 1ong-range plans. Many of the conceptual mine plans were submitted in 1976-78 in response to DOI requests for information on diligent development or for inclusion in regional coal statements and have not been updated to include information for permit approval under the Surface Mining Control and Reclamation Act of 1977 (SMCRA). Table 41 summarizes the acreage and reserves for these proposed mines, and table 42 shows the estimated capacity and production.

The 25 pending mine plans include 4 new surface mines (2 in New Mexico, 2 in Utah) and 21 new underground mines (11 in Colorado, 9 in Utah, and 1 in New Mexico). The two Utah surface mines also include some underground operations. The total annual production capacity of these proposed mines at full operation is 71.6 million tons. About 25 million tons is surface mine capacity and 47 million tons is underground mine capacity. Most of these mines will not reach full capacity until the 1990's. The proposed underground mines range in size from some with annual capacity between 100,000 and 500,000 tons per year to several new, large mines capable of producing over 1 million tons per year. Several of the largest proposed underground mines would produce over 10 million tons annually. The proposed new surface mines range in size from 1.6 million to more than 11 million tons of annual production capacity. Two of the proposed surface mines are in areas where there is currently no large-scale surface coal mining activity—the Alton Field of Southwestern Utah and the central San Juan basin of New Mexico.

All of the proposed mines are scheduled to begin production over the next decade. The more technically complete and active mine plan proposals will probably receive the necessary permits and begin construction in the next few years. Some of these will be producing by 1986. Initiation of production from several mines with inactive mine plans is less certain. According to mine plan estimates, about 16.9 million tons will be produced from proposed mines with Federal leases in the Southern Rocky Mountain States in 1986. By 1991, production from proposed mines with Federal leases is expected to be between 28.1 million tons and 49.1 million tons. The range

Table 41.—Summary of Mine Plan, Federal Lease Acreage and Recoverable Reserves Pending Mine Plans—Colorado, New Mexico, and Utah, Sept. 30,1980 (all reserves shown in millions of tons)

State/region	Number of leases	Number of mine plans	Total mine plan acres	Total Federal mine plan acres	Total Federal lease acres	Total mine plan reserves: Underground	Total mine plan reserves: Surface	Total mine plan reserves: Total	Total Federal lease reserves: Underground	Total Federal lease reserves: Surface	Total Federal lease reserves: Total
Colorado											
Green River	3[a]	3	3,150[a]	3,150[a]	3,150[a]	31[b]	0	31[b]	28[b]	0	28[b]
Uinta	18	8	39,144	34,704	34,704	423	0	423	427	0	427
San Juan	—	—	—	—	—	—	—	—	—	—	—
Denver-Raton Mesa	—	—	—	—	—	—	—	—	—	—	—
Total	21	11	42,293	37,854	37,854	454	0	454	455	0	455
New Mexico											
San Juan	9	3	29,580	14,979	21,098	42	352	394	56	127	183
Denver-Raton Mesa	—	—	—	—	—	—	—	—	—	—	—
Total	9	3	29,580	14,979	21,098	42	352	394	56	127	183
Utah											
Uinta	14[d]	8	33,020	19,902	25,711	300	15	315	247	17	264
Southwestern Utah	64	3	116,949	93,029	93,029	100	823	923	776	230	1,006
Total	78	11	149,969	112,931	118,740	400	838	1,236	1,023	247	1,270

[a]Excludes one lease in Trout Creek underground mine that is also part of approved Edna surface mine: acreage figures have been adjusted to avoid double counting.
[b]Reserves totals Include Trout Creek Mine underground reserves
[c]Acreage totals include leased area in approved Bear Mine that is also Part Of proposed Mt Gunnison Mine
[d]Excludes three leases in the proposed O'Connor Mine that are also partly covered by the approved Skyline and Belina mines Acreage and reserves figures include actual lease portions in the O'Connor mine plan

Acreage and reserves may not add to totals because of Independent rounding

SOURCE: Office of Technology Assessment; mine plan review.

Table 42.—Mine Capacity and Projected Production: Leases in Pending Mine Plans, Colorado, New Mexico, and Utah (all capacity and production in millions of tons)

				1986		1991	
State/basin	Number of mine plans with Federal leases	Number of Federal leases in these plans	Total maximum capacity in pending mine plans	Maximum* capacity of mines producing in 1986	Projected production from mines with Federal leases	Maximum capacity of mines producing in 1991	Projected production from mines with Federal leases
Colorado							
Green River	3	4[a]	2.3	2.3	1.3	2.3	1.8
Uinta	8	18	11.1	8.7	2.8	11.1	7.4
San Juan	0	0	0	0	0	0	0
Denver-Raton Mesa	0	0	0	0	0	0	0
Total	11	22	13.4	11.0	4.1	13.4	9.3
New *Mexico*							
San Juan	3	9	15.3	15.3	6.6	15.3	7.5-10.5
Denver-Raton Mesa	0	0	0	0	0	0	0
Total	3	9	15.3	15.3	6.6	15.3	7.5-10.5
Utah							
Uinta	8	17[b]	13.1	11.9	5.6	13.1	11.3
Southwestern Utah	3	68	29.8	11	0-0.6	29.8	0-18.0
Total.	11	85	42.9	22.9	5.6-6.2	42.9	11.3 -29.3
Regional total	25	116	71.6	49.2	16.3 -16.9	71.6	28.1 -49.1

[a]Includes one lease also in an approved plan
[b]Includes three leases also in approved plans.
* Maximum capacity means highest annual production from mine operating at full design capacity level and not the Installed capacity in place in 1986 or 1991 Actual Installed capacity for most mines in Southern Rocky Mountains wiIl be at or near the projected production levels
Product Ion and capacity columns may not add to totals because of Independent rounding

SOURCE' Off Ice of Technology Assessment

in production reflects uncertainties about the pace and scale of planned mine construction.

At least seven of the new mines with pending plans will not begin production until after 1986. There are several reasons for this: 1) some new mines are replacement capacity for existing operations and will not open until the active mines shut down or reduce production; 2) other mines are being developed under difficult mining conditions, and thus require longer periods for construction, and 3) several mines are intended to supply new powerplants that have been delayed or deferred. The planned production dates show that some operators clearly intend to open mines according to their own schedules and market situations rather than to accelerate development or project early starts to meet 1986 diligence requirements. All of the operators expect to qualify for extensions or modification of the diligence requirements under current guidelines,

Despite the optimism reflected in pending mine plans, OTA's analysis indicates that production from some of these mines is uncertain. In several instances, the mine plans appear to be inactive and the lessee has not proceeded with development according to the original plan schedule. Moreover, because of the substantial difficulties facing developers in Southwestern Utah, it is likely that the proposed mines there will not open in the late 1980's as originally announced, if at all.

Colorado.—Proposed mine plans for 11 new mines on Federal leases in Colorado have been filed for review by DOI. The plans include 21 leases with a total acreage of over 37,000 acres and with estimated recoverable reserves in excess of 450 million tons. All of the proposed new mines are underground operations, All but three of the pending mine plans are in the Uinta region. The production capacity of the pending mine plans at full operation is over 13 million tons per year.

For 1986, these mines are projected to produce about 4 million tons. By 1991, production is estimated to increase to around 9.3 million tons. Several of the mines are expansions or replacements of existing capacity. Many of the pending Colorado mine plans were recently submitted or updated. Although markets for some mines are still unknown, at least two of the new mines have contracts or letters of intent to supply existing or planned powerplants. See the Colorado appendix for additional information on pending mine plans in Colorado.

New **Mexico.—** Mine plans were recently submitted for three new mines on Federal leases in the San Juan basin of New Mexico. The plans include nine Federal leases covering over 21,000 acres and 183 million tons of recoverable reserves. The proposals include two new large surface mines in the Star Lake-Bisti area and one underground mine that will produce coal for industrial use. Total production capacity for these mines is 15.3 million tons per year. By 1986, OTA estimates that production could approach 6.6 million tons, or about 43 percent of full capacity. The production estimates for 1991 are more variable, and range between 7.5 million and 10.5 million tons depending on the rate of mine construction of the proposed surface mines.

Portions of two Federal leases in the proposed Bisti Mine are under review for exchange for unleased Federal coal. The exchange is not expected to delay mine construction. Production from the Bisti Mine will supply the San Juan Power Plant and the as-yet-unsited New Mexico Generating Station. The Star Lake Mine is associated with pending PRLAs; the attainment of full commercial production at Star Lake Mine is contingent on the availability of PRLA reserves and on construction of the Star Lake Railroad for access to out-of-State markets. See the New Mexico appendix for additional information on these mines.

Utah.—Eleven new mines on Federal leases in Utah have been proposed. The mines contain 78 Federal leases and over 118,000 acres of Federal land with nearly 1.3 billion tons of recoverable coal reserves. The mine plans cover almost 150,000 acres, and the total mine plan reserves, which include both Federal and non-Federal coal, are over 1.2 billion tons. (Total mine plan reserves are less than the total lease reserves because plans currently do not cover all of the leased land.) Eight of the mines are located in central Utah and three are in Southwestern Utah. The proposed mine plans include nine new underground mines and two new surface mines—the first strip mines on Federal leases in Utah.

The total annual capacity of these proposed mines at full production is 42.9 million tons. The smallest of the mines will produce 220,000 tons per year at full capacity; the largest mine will have an annual capacity of 12 million tons. The three mines in Southwestern Utah have a total proposed capacity of 29.8 million tons per year. Several mines will not reach full production levels on current schedules until the late 1980's or early 1990's. Markets for several of the new mines in Utah are as yet unknown, although at least 4,2 million tons of capacity can be considered captive production.

According to the pending mine plans, total production could reach 6.2 million tons by 1986. As the new mines near full-scale operations in 1991, total production is expected to be between 11.3 million and 29.3 million tons, depending on whether the three mines in Southwestern Utah open as planned. The rate of production from several mines in central Utah could be less than currently projected because of changes in construction plans for associated projects. See the Utah appendix for additional information on the uncertainties in the potential production from pending mine plans.

Undeveloped Leases

In the three Southern Rocky Mountain States there are 139 Federal coal leases classified as undeveloped (without mine plans). Table 43 shows the acreage and reserves for undeveloped leases in Colorado, New Mexico, and Utah. These 139 leases are divided into 77 lease blocks and contain over 2.3 billion tons of reserves. OTA's review of the reserves and mining conditions on the leases found that 96 leases in 37 minable blocks with 95 percent of the undeveloped lease reserves could support new mining operations. OTA's analysis further showed that most, but not all of these 96 leases, could be developed over the next decade. In addition, there are a small number of leases that could be mined as part of adjoining operations on existing or new base tracts.

OTA identified 42 leases with 599 million tons of reserves that actually have favorable prospects for development by 1991. An additional 54 leases with over 1.5 billion tons of reserves have uncertain prospects for development. Forty-three leases with 219 million tons of reserves were found to have unfavorable development potential. Over 70 percent of the lease reserves with favorable development potential are found in the Uinta region of central Utah. Almost all of the reserves with uncertain development potential are located in the Green River region of Colorado and in Southwestern Utah. The major uncertainties associated with lease development are: 1) markets; 2) construction of proposed transportation systems; and 3) availability of additional reserves. Most of the leases that were found to have unfavorable potential for development are small isolated lease tracts with limited reserves.

Table 43.—Undeveloped Leases in Colorado, New Mexico, and Utah: Acreage and Recoverable Reserves

State/region	Total number of leases	Total number of lease blocks	Total Federal acres	Total recoverable reserves (millions of tons)
Colorado				
Green River	23	21	24,417	816
Uinta	23	11	18,850	173
San Juan	0	0	0	0
Denver-Raton Mesa	6	4	3,686	66
Total	52	36	46,953	1,055
New Mexico				
San Juan	8	7	4,634	95
Denver-Raton Mesa	3	3	200	0.5
Total	11	10	4,834	95
Utah				
Uinta	44	20	47,679	447
Southwestern Utah	32	11	57,537	744
Total	76	31	105,215	1,191
Regional total	139	77	157,002	2,341

Acreage and reserves may not add 10 totals because of Independent rounding
SOURCE. Office of Technology Assessment.

Potential production from undeveloped leases that were rated as favorable or uncertain development prospects is estimated to be only about 800,000 tons by 1986, however by 1991, potential production from these leases could range between 16.8 million and 32.2 million tons depending on the rate of mine construction and resolution of various uncertainties. The undeveloped leases could contribute between 32 million and 55 million tons of new annual capacity and 2.6 million tons of replacement capacity,

Summary of Undeveloped Lease Statistics

Of the 360 Federal leases in the region, 39 percent are classified as undeveloped. They cover more than 157,000 acres, or about 35 percent of land under lease in the three States, and include over 2.3 billion tons of recoverable reserves, or over 39 percent of the leased reserves in these States. Of all leases identified as undeveloped by OTA, 56 percent are located in this region.

Utah, with 76 undeveloped leases, has more than half of the region's undeveloped leases; there are 52 undeveloped leases in Colorado and 11 in New Mexico. Utah and Colorado each have slightly over 1 billion tons of undeveloped lease reserves. Nearly all of New Mexico's undeveloped reserves are surface minable; in contrast, most of the undeveloped lease reserves in Utah must be deep mined. Slightly more than half of Colorado's undeveloped lease reserves are accessible by underground methods; the rest can be surface mined.

The undeveloped leases in the Southern Rocky Mountain region vary widely in character. At least 13 lease blocks are part of proposed mining projects for which mine plans are nearly completed. Another 13 blocks with 17 leases are small tracts of less than 100 acres that formerly sustained small underground mines serving local markets. These mines closed for various reasons: 1) inability to meet increased health and safety requirements; 2) difficult mining conditions; 3) depleted reserves; or 4) a decline in local markets. Many of these smaller leases are located in the isolated mountainous areas. Several large multilease blocks in remote areas are also isolated from potential markets because of lack of rail service. Two of these lease areas—Southwestern Utah and the Star Lake-Bisti area of the San Juan basin in New Mexico—also present possible environmental conflicts for large-scale coal developers because of potential impacts on nearby national parks, monuments and other scenic and archeological resources.

OTA has grouped the 139 undeveloped leases in the Southern Rocky Mountain region into 77 blocks of contiguous leases that are owned by the same lessee(s). Each block will probably be mined as one operation if developed. The blocks range from single leases of 40 acres to multilease blocks with as many as 10 leases and a total of more than 25,000 acres.

Colorado has the largest number of lease blocks, 36, of which 31 are single lease blocks and 5 are multilease blocks. New Mexico's 11 undeveloped leases are divided into 10 blocks. Seven of these are single lease blocks of less than 160 acres, one is a two lease block of 160 acres, and two are large leases, each with enough reserves to sustain a new large mine.

Utah's 76 leases are divided into 31 lease blocks—20 blocks in central Utah and 11 blocks in Southwestern Utah. These blocks include 12 multilease blocks and 19 single lease blocks. The single lease blocks in Utah range in size from 40 acres to 1,908 acres.

The Colorado, New Mexico, and Utah sections of the appendix to this report describe the lease blocks in more detail.

Assessing the Development Potential of Undeveloped Leases (in Colorado, New Mexico, and Utah)

OTA's analysis of undeveloped leases included an assessment of each lease block to determine which blocks could potentially support a new mine. OTA compared the resource characteristics of each block with those of active or proposed mines in the same region. Both large and small mines were included in the regional mine profiles. * The following criteria were used:

1. Approximate mining unit. Is the lease block compact, contiguous, and under single ownership to allow for orderly development as a mining unit?
2. Coal *reserves.* Are the recoverable coal reserves within the lease block sufficient to support a competitively sized new mine, i.e., large mines producing 0.5 million to 1.0 million tons per year; small mines producing 50,000 tons per year?
3. Coal quality. Do the coal reserves meet minimum Btu, sulfur, and ash quality standards for the expected end use, e.g., steam coal, industrial use, synthetic fuels?
4. Geological characteristics. Do the geological conditions of the coal reserve such as depth of overburden, seam thickness and dip, and surface topography permit efficient mine design and economic coal recovery comparable to other operating mines in the area?

When the quality and quantity of the reserves and the potential mining conditions on the lease blocks are considered, 37 blocks with a total of 96 leases were found to have sufficient minable reserves to sustain a new mine without additional Federal or non-Federal reserves. Of these 37 blocks, 10 lease blocks could support new small mines. It is from these 96 Federal leases with sufficient amounts of good quality minable reserves that most, if not all, of the new production

*These profiles and the results of OTA's evaluation of property characteristics are discussed in detail in the State task force reports.

from existing Federal leases will come. See table 44 for the results of OTA's review of the resource characteristics of undeveloped leases.

In addition to the resource characteristics, OTA's analysis of the development potential of leases without mine plans also included an evaluation of other factors, such as market conditions, transportation availability, and environmental requirements, that will influence whether a lease will go into production, For the Southern Rocky Mountain region, OTA found that the undeveloped leases divide almost evenly among three categories: favorable, uncertain, and unfavorable development prospects. The leases, acreage and reserves in these categories are summarized in table 45. Forty-two leases (13 blocks) were rated as favorable prospects for development by 1991; 54 leases (28 blocks) were rated as uncertain; and 43 leases (36 blocks] were rated as unfavorable. Only 9 percent of the undeveloped lease reserves are included in blocks with unfavorable development potential. Roughly 65 percent of the undeveloped reserves, 1.5 billion tons, fell into the uncertain category and 599 million tons, or 25 percent of the undeveloped reserves in the region received a favorable rating. As a result of the analysis of the prospects for development of existing leases, several lease blocks with minable reserves that could support new mines were found to have little chance of actually going into production in the next decade. A small number of leases that could not independently support viable mining operations were found to have some potential for development in association with adjacent Federal or non-Federal reserves.

At least 17 leases (5 blocks) with favorable ratings are part of proposed mining projects with mine plans in preparation and potential customers for future production. The lease blocks with favorable prospects for development also include several large tracts of excellent reserves for which current development plans are unknown. The undeveloped leases with unfavorable development potential include many single lease tracts with small reserves as well as several larger tracts in areas that are not likely to be linked to an adequate coal transportation system within the next 10 years. Some of the leases receiving uncertain development prospect ratings face resolvable development problems such as potentially adverse environmental impacts, uncertainties about construction of proposed transportation systems,

Table 44.—Resource Characteristics of Undeveloped Leases: Colorado, New Mexico, and Utah (all reserves in millions of tons)

State/region	Leases in blocks with sufficient good quality minable reserves to support a new mine: Number of leases	Number of blocks	Acres	Recoverable reserves	Leases in blocks that do not have enough good quality minable reserves to support a new mine: Number of leases	Number of blocks	Acres	Recoverable reserves
Colorado	39	23	44,274	1,017	13	13	2,679	38
Green River	16	14	22,970	792	7	7	1,447	24
Uinta	18	6	17,658	159	5	5	1,192	14
Denver-Raton Mesa	5	3	3,646	66	1	1	40	0.1
New Mexico	2	2	3,954	94	9	8	880	1.5
San Juan	2	2	3,954	94	6	5	680	1.0
Denver-Raton Mesa	0	0	0	0	3	3	200	0.5
Utah	55	12	99,274	1,119	21	19	5,942	67
Uinta	30	8	44,658	417	14	12	3,021	25
Southwestern Utah	25	4	54,616	702	7	7	2,921	42
Regional total	96	37	147,502	2,230	43	40	9,501	106

NOTE Columns may not add to totals because of independent rounding

SOURCE: Off Ice of Technology Assessment

Table 45.—Summary of Development Potential of Undeveloped Leases in Colorado, New Mexico, and Utah

	Favorable development potential				Uncertain development potential				Unfavorable development potential			
State/region	Number of leases	Number of blocks	Acres	Recoverable reserves (millions of tons)	Number of leases	Number of blocks	Acres	Recoverable reserves (millions of tons)	Number of leases	Number of blocks	Acres	Recoverable reserves (millions of tons)
Colorado												
Green River	2	2	3,600	37	14	12	17,815	739	7	7	3,002	40
Uinta	8	1	3,469	47	3	3	1,866	29	12	7	13,514	97
Denver-Raton Mesa	0	0	0	0	4	2	2,684	49	2	2	1,002	17
Total	10	3	7,069	84	21	17	22,365	817	21	16	17,518	154
New Mexico												
San Juan	2	2	3,954	93	3	2	320	0.6	3	3	360	0.5
Denver-Raton Mesa	0	0	0	0	2	2	160	0.4	1	1	40	0.1
Total	2	2	3,954	93	5	4	480	1.0	4	4	400	0.5
Utah												
Uinta	30	8	44,658	422	3	3	560	3	11	9	2,461	22
Southwestern Utah	0	0	0	0	25	4	54,616	702	7	7	2,921	42
Total	30	8	44,658	422	28	7	55,176	705	18	16	5,382	64
Regional total	42	13	55,681	599	54	28	78,021	1,523	43	36	23,300	219

Acreage and reserves may not add to totals because of independent rounding

SOURCE: Office of Technology Assessment.

or difficulties in marketing coal competitively in the current era of overcapacity.

OTA's analysis identified 96 leases in the Southern Rocky Mountain region that have favorable or uncertain prospects for development in the next decade. These leases contain over 2. I billion tons of reserves—over 90 percent of the undeveloped Federal lease reserves in the three States. While a classification of favorable or uncertain does not mean that OTA has found that the lease will definitely go into production by 1991, it is probable that many of these leases will in fact be mined because they include very good reserves and the market situations for those states show at least limited opportunities for expanded coal production.

Production Prospects for Undeveloped Leases

The potential production and mine capacity for Federal leases with favorable or uncertain development prospects are summarized in table 46. OTA's production and capacity projections represent a rough estimate of the production and capacity that could be supported by each block based on consideration of the amount and type of reserves and expected mining conditions for each block.

OTA identified only two undeveloped leases, one in the Green River region of Colorado, and one in the San Juan basin of New Mexico, which are expected to be in production by 1986. Together they could yield 0.8 million tons in 1986. One of the leases is already committed to supply an existing powerplant; the other is associated with a proposed mine on adjacent non-Federal land serving a local powerplant.

By 1991, 23 blocks including 77 leases (55 percent of the total undeveloped leases in the Southern Rockies) could be in production. If all 22 mines on these leases were developed, they could produce between 16.8 million and 32.2 million tons of coal in 1991. If a very strong coal market develops, however, production could approach the total maximum capacity of 57.7 million tons that these leases could support. Twelve of the 23 lease blocks which might be in production in 1991 have favorable development prospects. The remaining 11 blocks have uncertain prospects for a variety of reasons including lack of transportation, uncertain markets, and the need for additional reserves. Despite these current

Table 46.—Summary of Potential Production and Mine Capacity for Undeveloped Leases With Favorable or Uncertain Development Prospects in Colorado, New Mexico, and Utah
(all production and capacity in million of tons)

State/region development potential	Total number of Leases	Total number of Blocks	Estimated production in 1986[a]: Number of producing Leases	Number of producing Blocks	Maximum mine capacity[b]	Estimated production	Estimated production in 1991a: Number of producing Leases	Number of producing Blocks	Maximum mine capacity[b]	Estimated production
Colorado ...	**31**	**20**	1	1	**0.6**	**0.6**	**22**	**10**	**12.2 -17.7**	**8.1**
Green River										
Favorable	2	2	1	1	0.6	0.6	2	2	1.6	1.6
Uncertain	14	12	0	0	0	0	8	5	8.6-14.1	4.8
Uinta										
Favorable	8	1	0	0	0	0	8	1	1.0	0.8
Uncertain	3	3	0	0	0	0	1	1	0.5	0.5
Denver-Raton-Mesa										
Favorable	0	0	0	0	0	0	0	0	0	0
Uncertain	4	2	0	0	0	0	3	1	0.5	0.5
New Mexico. .,	**7**	**6**	1	1	**2.0**	**0.2**	**2**	**2**	**4.0-12.0**	**1.7-8.0**
San Juan										
Favorable. . . .	**2**	**2**	1	1	**2.0**	**0.2**	**2**	**2**	**4.0-12.0**	**1.7-8.0**
Uncertain	**3**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Denver-Raton-Mesa										
Favorable. . .	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Uncertain	**2**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Utah	**58**	**15**	**0**	**0**	**0**	**0**	**53**	**11**	**18.5 -28.0**	**7.0-16.0**
Uinta										
Favorable. . . .	**30**	**8**	**0**	**0**	**0**	**0**	**28**	**7**	**12.0**	**7.0-8,6**
Uncertain	**3**	**3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Southwestern Utah										
Favorable, . .	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Uncertain	**25**	**4**	**0**	**0**	**0**	**0**	**25**	**4**	**6.5-16.0**	**0-7.4**
Total	96	41	2	2	2.6	0.8	77	23	34.7 -57.7	16.8 -32.2

Capacity and production columns may not add to totals because of Independent rounding.

[a]Some leases have favorable or uncertain development potential because they could be mined as part of adjacent operations. In almost all of these case, the estimated Federal production would be very small and thus, neither those leases nor the possible production are shown in the production and capacity estimates above.

[b]Maximum capacity means the actual amount of coal that could be produced by the mine operating at full production levels and not the actual installed capacity in place by 1986 or 1991 Actual Installed capacity for new mines with Federal leases in those years will be at or near the estimated production level

SOURCE Office of Technology Assessment

problems, the lessees of 13 blocks are planning for development and the outlook for resolving their problems is good enough to support a forecast of some coal production from their leases by 1991.

According to OTA's analysis, a total of 77 of the 96 undeveloped leases with favorable or uncertain development potential are likely to be in production within the next decade. The remaining leases, 17 of which received uncertain development prospect ratings and two of which received favorable development prospect ratings, either are not as likely to overcome the probable obstacles to development by 1991 or will contribute only very small production.

Colorado.—Colorado has 52 undeveloped leases with a total of over 1 billion tons of recoverable reserves. The Green River region has 23 undeveloped leases and 77 percent of the undeveloped lease reserves in the State.

Ten Colorado leases in three lease blocks with a total of 78 million tons of recoverable reserves were classified as favorable development prospects. All of the leases are located in western Colorado and all are part of new mine projects that have not yet sub-

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mitted mine plans. One of the leases is expected to be producing at it's planned capacity of 600,000 tons per year by 1986; the other two blocks could produce 1.8 million tons in 1991 out of a total planned capacity of 2 million tons (see table 45).

Twenty-one leases were classified as uncertain prospects for development. Over 90 percent of the 817 million tons of lease reserves rated as uncertain are found in the Green River region of northwest Colorado. Several very large tracts of underground and surface recoverable reserves are included in this category. The uncertain rankings were based on a variety of considerations that were different for each lease block, including coal quality, the availability of additional reserves from PRLAs or new Federal leases, transportation problems, and uncertain coal demand due to the slow pace of construction of planned powerplants and coal-based synthetic fuel projects. Almost all of these lessees are proceeding with mine plan development. By 1991, these leases with uncertain development prospects could produce up to 5.8 million tons with an eventual capacity of between 9.6 million and 15.1 million tons per year depending on the mine design.

Colorado has more leases and reserves rated as unfavorable development prospects than New Mexico and Utah combined. Even so, only 15 percent of the undeveloped lease reserves in Colorado were found to be unlikely to be developed. Twenty-one leases in 16 blocks with 154 million tons of reserves were classified as unfavorable development prospects. Most of the unfavorable lease blocks were single lease tracts with small amounts of reserves. Two blocks in the Tongue Mesa Field with a significant amount of good quality minable reserves were rated as unfavorable because the area is not served by adequate coal transportation. These two blocks were the only large blocks in the three-State region that were found to have little potential for development in the next 10 years. See the Colorado appendix for additional information on potential production from undeveloped leases in the State.

New Mexico.—There are 11 undeveloped leases with 95 million tons of recoverable reserves in New Mexico; 8 of these leases and over 99 percent of the reserves are located in the San Juan basin of northwest New Mexico. The Raton Mesa region in the northeast has three scattered Federal leases that once supported small mines.

Two large leases in the San Juan basin were found to have favorable potential for development. These two leases cover 82 percent of the acreage of undeveloped leases and contain nearly all of the undeveloped reserves. These leases could produce 200,000 tons in 1986 and from 1.7 million to 8 million tons in 1991 depending on the rate of mine expansion.

One block is located in the northern part of the basin near Farmington and is associated with the proposed La Plata Mine on adjacent non-Federal land. Production from this lease will probably be sold to the San Juan powerplant. The other lease is located at Black Lake in the Star Lake-Bisti area of the south-central part of the basin, and is associated with several pending PRLAs At least a portion of the production will reportedly be used in the proposed Texas Eastern Synfuels coal gasification project. Coal from the mine would be shipped on the Star Lake Railroad. Both leases would be surface mined. Mine plans were submitted to the State surface mine agency after OTA's analysis was completed.

Five leases were rated as having uncertain development prospects including three leases in the San Juan basin and two leases in the Raton Mesa region. All of the leases are less than 160 acres and contain a total of about 1 million tons of reserves. These leases could be developed only in association with adjacent properties. It is unknown whether operating agreements or assignments for such development have been negotiated. The amount of production from these leases would be very small. The four remaining leases were found to have unfavorable development prospects. See the New Mexico appendix for additional information on these leases, Utah.—There are 76 leases without mine plans in Utah. These leases are divided into 31 lease blocks containing about 1.2 billion tons of recoverable reserves, nearly all of which are accessible by underground mining. Thirty-two leases with over 63 percent of the undeveloped lease reserves are found in southwestern Utah, which currently has no active coal mining operations. Several hundred million tons of reserves are contained in large multilease blocks on the rugged and isolated Kaiparowits Plateau.

OTA identified 301 eases in 8 1ease blocks in central Utah that have favorable prospects for development in the next decade. These leases cover some of the best quality undeveloped coal reserves currently under lease. Several of the blocks contain metallurgical coal reserves. Most of the reserves would be deep mined, but portions of one block could probably be strip mined. These 30 leases include over 70 percent of the undeveloped lease reserves with favorable development potential in the entire Southern Rocky Mountain region. These leases could produce up to 8.6 million tons in 1991 with maximum mine capacity reaching 9 million to 12 million tons per year in the mid-1990's.

Twenty-eight leases in seven lease blocks were found to have uncertain prospects for development. Three small leases in central Utah have uncertain development prospects because the lessees reportedly intend to mine the leases in conjunction with adjacent or nearby operations. The amount of reserves and annual production are small. Over 702 million of the 705 million tons of reserves rated as uncertain for development are contained in 25 leases located in four blocks on the Kaiparowits Plateau in southwestern Utah. Production from these leases is highly uncertain because of their distance from rail service, lack of established communities, difficult underground mining conditions, and potential environmental conflicts resulting from development. These lease reserves could support mines with an eventual annual capacity of between 6.5 million and 16 million tons per year depending on the mine size. OTA estimates that these mines could produce between zero and 7,4 million tons in 1991.

Utah's undeveloped leases with favorable and uncertain development potential could add as many as 11 new Federal mines by 1991 with a total capacity of 18.5 million to 28 million tons. The production capability of the individual mines ranges from less than I00,000 tons to more than 6.0 million tons per year.

The remaining 18 leases in Utah were found to have unfavorable prospects for development. These 16 blocks with 64 million tons of reserves consist of small, scattered lease tracts, many of which once supported small mines. None of the lease tracts have enough good quality reserves remaining to support even a new small mine. Several undeveloped leases in central Utah are adjacent to Utah Power & Light's Deer Creek-Wilberg Mine complex and to several proposed new lease tracts. These unfavorable leases could conceivably be combined with adjacent operations. However, as of May 1980, when OTA completed its review of these leases, no such action had been taken. Only 29 percent of the undeveloped reserves in the region with unfavorable development ratings are located in Utah. The Utah appendix discusses the location, production potential, and development uncertainties of leases without mine plans in central and southwestern Utah.

Development Potential and Production Prospects of Federal Coal Leases in North Dakota, Montana, and Wyoming

The areas of the Northern Great Plains coal province and the northern portion of the Rocky Mountain coal province which contain leased Federal coal are located in Montana, North Dakota, and Wyoming (see fig. 2 in ch. I). The Fort Union lignite region of western North Dakota and east-central Montana, and the Powder River basin of southeastern Montana and northeastern Wyoming are located in the Northern Great Plains coal province. In southern Wyoming, which is located in the northern portion of the Rocky Mountain province, the Hanna Field, the Rock Springs Field, and the Kemmerer Field contain significant amounts of leased Federal coal (see fig. 3 in ch. 1). *

There are 137 existing Federal coal leases in these three regions covering nearly 273,000 acres and containing 10.3 billion tons of recoverable reserves.** These regions have 24 percent of the total Federal leases, 34 percent of the acreage under lease, and 62 percent of the reserves under lease. Sixty-eight of the leases in this three-state area are in approved mine plans; only nine are in pending mine plans; the remaining 60 leases are not in mine plans, and are referred to as undeveloped leases in this report. Coal production from mines with Federal leases in North Dakota, Montana, and Wyoming was 109 million tons in 1979 or over 90 percent of the total production of 119 million tons in these three States and over 75 percent of the total production of all mines with Federal leases in the West. *

*PPL's Cherokee lease block is technically part of the Little Snake River Field in southern Wyoming, but is included in the Rock Springs Field in the numerical analysis in this chapter.

**By confining the discussion in this section to the Fort Union region, the Powder River basin and the Hanna, Rock Springs, and Kemmerer fields of southern Wyoming, three small leases in Montana in the Yellowstone and Bull Mountain region, and two small leases in Wyoming in the Big Horn basin are omitted. Four of these leases have unfavorable development potential. The fifth, in Montana, is currently producing.

Summary of Production Potential and Planned Capacity

Table 47 summarizes the production potential of all mines with Federal coal leases in North Dakota, Montana, and Wyoming. Operating mines with Federal leases in these three States produced 109 million tons of coal in 1979. According to the lessees' plans, Federal mines in currently approved mine plans are scheduled to produce 232 million tons in 1986 and 260 million tons in 1991. OTA estimates that under favorable market conditions mines with Federal leases in pending mine plans and undeveloped Federal leases located in this three-State area will contribute an additional 32 million tons of coal production in 1986 and 97 million tons in 1991, If these OTA estimates and the lessees' plans are realized, total production from mines with Federal coal leases in North Dakota, Montana, and Wyoming will be 264 million tons in 1986 and 357 million tons in 1991.

In the Powder River basin of Wyoming and Montana, Federal mines accounted for 88 percent of total coal mine capacity in 1980. This percentage is projected to remain relatively constant throughout the decade. However, production from Federal leases them-

*Coal from Federal coal leases is referred to as **Federal coal.** A mine that includes a Federal lease is called a **Federal mine.** Sometimes, for the sake of efficiency of recovery or economy of operations, intervening state or private coal is mined with Federal lease(s) in the same mine. This practice is the rule in Southern Wyoming and North Dakota. for example. Thus, many Federal mines produce both Federal and non-Federal coal. A mine that contains no Federal coal is called a **non-Federal** mine. Total coal production in a State or region is thus the sum of: 1) Federal coal product from from Federal mines **plus 2)** non-Federal coal production from Federal mines **plus 3)** non-Federal coal production from non-Federal mines.

Table 47.—Potential Production From Mines Containing Federal Coal Leases: North Dakota, Montana, and Wyoming (all production in million tons per year)

State/region	Production in 1979	Potential production in 1986: Federal mines in approved mine plans[a]	Potential production in 1986: Federal mines in pending mine plans and leases not in mine plans[b]	Potential production in 1986: Total	Potential production in 1991: Federal mines in approved mine plans[a]	Potential production in 1991: Federal mines in pending mine plans and leases not in mine plans[b]	Potential production in 1991: Total
North Dakota							
Fort Union	14.1[c]	12	15	27	12	20	32
Subtotals	14.1	12	15	27	12	20	32
Montana							
Fort Union	0.3	0.3	0.0	0.3	0.3	0.0	0.3
Powder River basin	27.1	46	0 to 1.6	46 to 48	49	0 to 8.8	49 to 58
Subtotals	27.4	47	0 to 1.6	47 to 48	49	0 to 8.8	49 to 58
Wyoming							
Powder River basin	44.5	144	5.6 to 9.5	150 to 154	170	17 to 56	186 to 225
Hanna Field	10.7	10	0.4 to 0.6	10 to 11	8	0.3 to 0.6	8 to 9
Rock Springs Field	7.2	13	1.3 to 2.0	14 to 15	15	1.1 to 7.0	16 to 22
Kemmerer Field	5.1	6	2.2 to 3.5	9 to 10	6	2.6 to 4.5	9 to 11
Subtotals	67.5	173	10 to 16	183 to 189	199	21 to 68	219 to 266
Totals	109	232	25 to 32	257 to 264	260	41 to 97	301 to 357

[a]With few exceptions, the lessee's planned production is used for approved mine plans (and for pending mine plans in North Dakota)
[b]Office of Technology Assessment estimates are used for pending mine plans (Wyoming) and for leases with no mine plans
[c]Includes 56 million tons of production from mines with Federal leases in currently pending mine plans.

SOURCE Office of Technology Assessment

selves is projected to increase from less than 40 percent of total coal production in the basin in 1979 to approximately 80 percent in 1991. In southern Wyoming, essentially all coal production is from Federal mines with about one-third of the production from the Federal leases, This pattern is expected to continue with the contribution from Federal reserves rising to perhaps 40 percent by 1991. In 1979, Federal mines in the North Dakota portion of the Fort Union region accounted for over 90 percent of the State's coal production; the amount produced from Federal reserves was less than 7 percent. This situation is expected to continue, with however, production from Federal reserves rising to perhaps 20 percent by 1991.

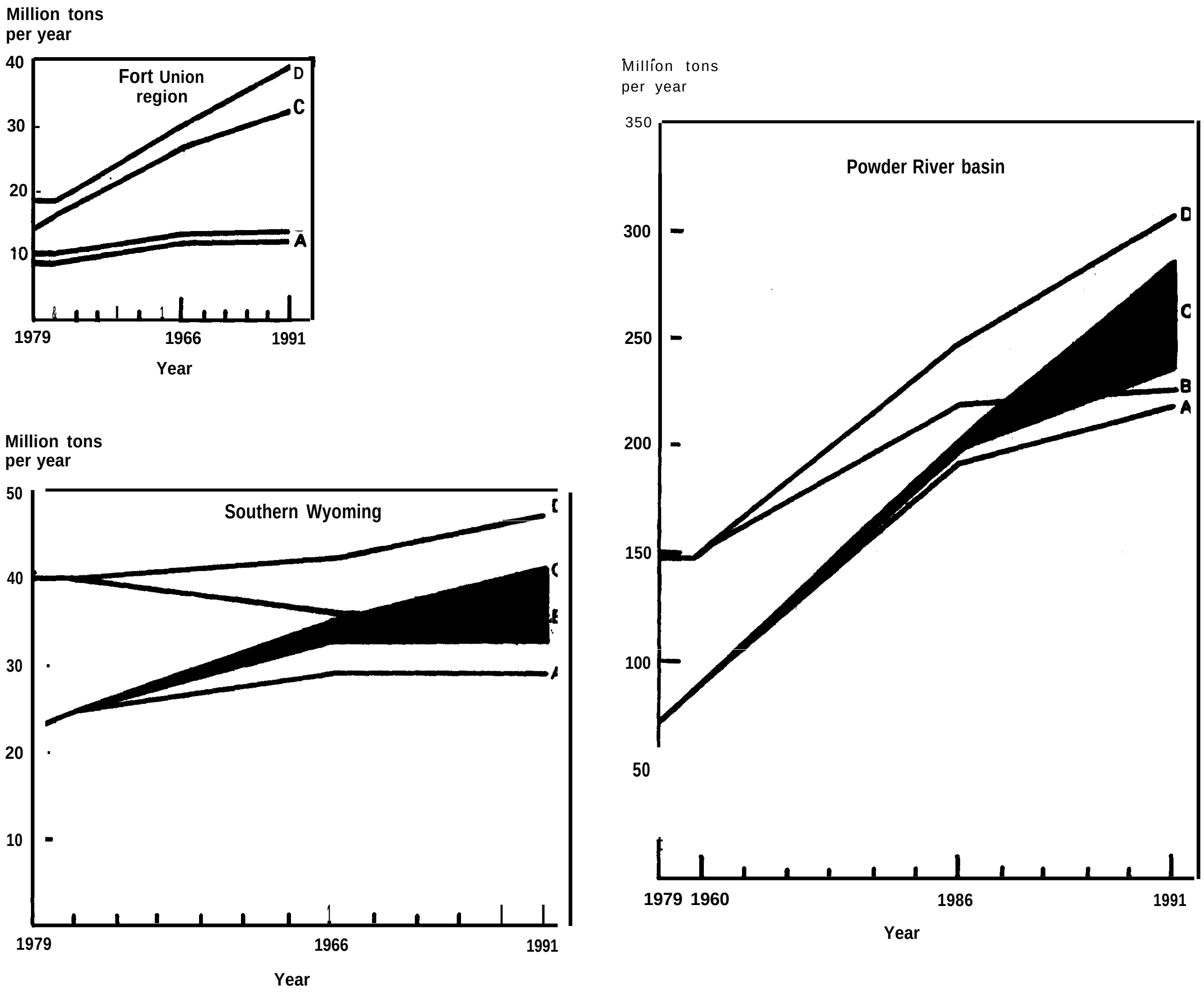
Figure 27 summarizes the potential production and planned capacity of all mines with Federal leases (including undeveloped leases) in the Fort Union region of North Dakota and Montana, the Powder River basin of Montana and Wyoming, and the coalfields of southern Wyoming. The upper capacity lines (lines D) in this figure represent OTA's estimate of the maximum coal production from Federal mines that could be achieved in these three regions under strong market conditions.

Several features of figure 27 should be noted:

1. The Powder River basin will continue to increase in importance as a coal-producing region, By 1991, Federal mine production in the Powder River basin could account for about 80 percent of Federal mine production in these three States. *
2. All estimated Federal mine production for 1991 for the Powder River basin comes from currently approved mines and from undeveloped leases with favorable development potential. (Undeveloped leases with uncertain develop-

*Because of the importance of the Powder River basin in Federal coal production, the development potential and production prospects of all Federal coal leases in this region are examined in more detail in ch. 7.

Figure 27.-Planned Capacity and Potential Production of All Mines With Federal Leases in the Powder River Basin, Southern Wyoming, and Fort Union Region



A: Lessee's planned annual production from Federal mines in currently approved mine plans only

B: Lessee's planned annual capacity for Federal mines in currently approved mine plans only

C: The sum of *A,* **above,** Plus estimates of potential production from Federal mines in pending mine plans and from presently undeveloped Federal leases

D: Planned annual capacity for all Federal mines, including Federal mines in pending **mine plans and presently undeveloped Federal leases**

SOURCE. Office of Technology Assessment.

ment potential contribute no production through 1991.) The large range in estimated production from undeveloped leases arises from demand uncertainty. However, several undeveloped leases in the basin have contracts for delivery of coal before 1990.

3. By 1991, the capacity of Federal mines in the Powder River basin could be as high as 310 million tons per year. According to the lessees' plans, the overcapacity in presently operating Federal mines in the Powder River basin, which was greater than 75 million tons per

year in 1979, will diminish to nearly zero by 1991,

4. The maintenance of total capacity of Federal mines in southern Wyoming depends on the development of new mines, Although capacity of presently operating mines is projected to decrease over the next 10 years, their production will probably not decline, Most of the range in production arises from uncertainty in the pace of a synfuels project.
5, The potential increase in production and capacity of Federal mines in the Fort Union region will occur largely from mines in North Dakota with leases in currently pending mine plans. Undeveloped leases are not likely to contribute more than 1 million tons per year by 1991. Federal mine production in the Montana portion of the region is likely to remain constant at 0.3 million tons per year.

The following subsections summarize the data presented in table 47 by State.

North Dakota.—Production from Federal mines with approved mine plans in the Fort Union region of North Dakota was 8,5 million tons in 1979. In 1986, these mines are projected to produce 12 million tons, a level of production that should remain constant through 1991. Production from Federal mines with mine plans pending was almost 6 million tons in 1979 and is expected to increase to 15 million tons in 1986 and to 20 million tons in 1991. Production of perhaps 1 million tons can be expected from undeveloped leases in North Dakota by 1991. Total production from Federal mines in North Dakota could reach 32 million tons by 1991,

Montana.—Production from mines with Federal leases in Montana in 1979 was 27.4 million tons, Virtually all of this production (27.1 million tons) came from the Powder River basin; production from a small Federal mine in the Fort Union region of Montana accounted for the balance. According to the lessees' plans, 47 million tons of coal will be produced in 1986 from mines with Federal leases already developed in the Montana Powder River basin. Production from the Montana leases in the Fort Union region is scheduled to remain at 0.3 million tons through 1991.

OTA estimates that 1.6 million tons of coal could be produced in 1986 and close to 9 million tons in 1991 from undeveloped Federal coal leases in the Montana portion of the Powder River basin. Lessee plans call for production of 49 million tons in 1991 from Federal mines in approved mine plans. If these estimates and plans are realized, production from Federal mines in Montana would reach 58 million tons per year in 1991. There are no leases with pending mine plans in Montana.

Wyoming.—Coal production from mines with Federal leases in the four regions of Wyoming— the Powder River basin, Hanna Field, Rock Springs Field, and Kemmerer Field—totaled 67.5 million tons of coal in 1979. Two-thirds of this production (44.5 million tons) came from the Wyoming portion of the Powder River basin. By 1986, according to the lessees' plans, production in this basin from Federal mines that now have approved mine plans will increase to 144 million tons. OTA estimates that an additional 10 million tons could be produced from undeveloped leases in the basin in 1986, giving planned and estimated production of 154 million tons in 1986. By 1991, production could increase to 225 million tons with 170 million tons coming from Federal mines that now have approved mine plans and 56 million tons from undeveloped leases.

Twenty-three million tons of coal was produced from mines with Federal leases in southern Wyoming in 1979. The lessees plan that production from currently operating mines will increase to 29 million tons in 1986 and remain constant through 1991. OTA estimates that production from currently undeveloped leases and leases in pending mine plans in this region could reach 6 million tons by 1986 and 12 million tons by 1991, for total southern Wyoming Federal mine production of 35 million tons in 1986 and 41 million tons in 1991.

Quality of Coal Under Lease

Of the 9 billion tons of recoverable coal reserves under lease in the Powder River basin, 7 million tons are subbituminous C, and 1.3 billion tons are subbituminous B.* There are small reserves of subbituminous A in the Montana portion of the Powder River basin. There are also Federal lignite reserves under lease in the Powder River basin. Several Federal mines and leases in southern Wyoming have reserves of bituminous coal, however most of the Federal reserves in southern Wyoming, including most of the reserves on undeveloped leases, are subbituminous. All Federal reserves in the Fort Union region are lignite.

Most of the Federal coal in the Powder River basin and the coalfields of southern Wyoming is low sulfur (i.e., less than 0.5 percent sulfur). Only one Federal mine in the Powder River basin produces coal with a sulfur content of over 1 percent.

Production and Consumption of Coal: Powder River Basin, Southern Wyoming, and the Fort Union Region

Coal seams in the Powder River basin typically range from 25 to 120 ft in thickness. Because of the thick seams which lie fairly close to the surface, all mines in the Powder River basin are surface mines. Large quantities of coal can be extracted at low cost from these mines. On a Btu basis, Powder River basin coal mine-mouth prices are the lowest of all coals, ranging from $0.42 to $0.65 per million Btu (see table 28). In addition, the mines in the Powder River basin are large. The Belle Ayr Mine in Wyoming is presently the largest coal mine in the United States; it produced 15 million tons in 1980. Four other mines in the basin are scheduled to reach a design capacity of 20 million tons per year or more by the end of the decade.

*The following Btu ranges are associated with different coal quality: 1 - Bituminous-high volatile A (greater than 14,000 Btu), B (14,000 to 13,000 Btu), C (13,000 to 12,000 Btu): 2- Sub bituminous—A (12,000 to 11,000 Btu), B (1 1,000 to 9,500 Btu), C (9,500 to 8,300 Btu); and 3- Lignite (8,300 to 5,500 Btu).

Steeply pitching, multiple coal seams are common in southern Wyoming where the recoverable reserves are usually much smaller and the stripping ratios higher than in the Powder River basin. Also, unlike the Powder River basin, underground mining has a long continuous history in southern Wyoming. Two underground mining operations in southern Wyoming, the Vanguard No. 2 and Carbon No. 1 mines, currently include Federal coal deposits.** Longwall mining techniques are being used or will be used to increase coal recovery at both of these mines to about 75 percent of minable reserves.

Surface mining in southern Wyoming is more complex and more costly than in the Powder River basin because of the steeply pitching and multiple coal seams. At some mines, such as the Elkol-Sorensen Mine which includes Federal reserves, combinations of draglines, truck/shovel operations, and dozer/scraper teams are used to develop large multiple open pits with depths that may reach 1500 ft. Up to 12 seams are mined at Elkol-Sorenson with an aggregate coal thickness of 300 ft and dips of 170 to 220. Another Federal mine in southern Wyoming, the Black Butte Mine, contains 13 coal seams ranging in thickness from 3 to 35 ft. Eleven pits will eventually be developed at Black Butte.

In the Wyoming portion of the Powder River basin, most Federal mines are compact units with little, if any non-Federal coal interspersed with the Federal reserves. Consequently, mining operations in this area involve predominantly Federal reserves. The occasional sections of State and fee coal are developed with the Federal reserves. By 1986, the Federal portion of coal production from these mines is expected to increase to well over 90 percent from the 1979 level of 49 percent. In southern Wyoming and in the area around Colstrip, Mont., on the other hand, most leased areas of Federal coal are checker-boarded with non-Federal coal and all LMUs include both Federal and non-Fed-

**Another underground Federal coal mine in this area, the Stansbury Mine, closed in early 1981 but is expected to reopen later in the decade.

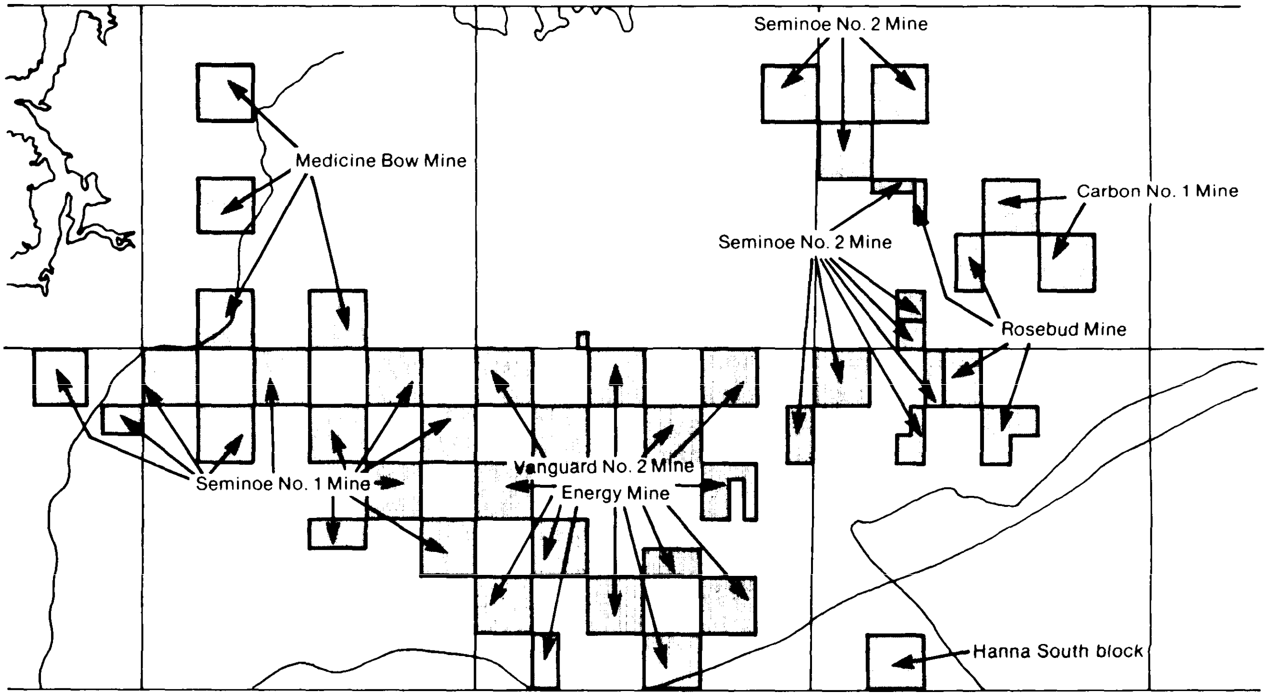
eral reserves. Orderly and efficient mining can be difficult where only part of the Federal coal reserves within the extended mine plan area are leased. These two patterns of reserve development are shown in figure 28, which illustrates patterns of Federal leaseholdings in southern Wyoming, and in figure 29, which illustrates patterns of Federal leaseholdings in the Wyoming portion of the Powder River basin.

Approximately 25 billion to 35 billion tons, about two-thirds of the Nation's lignite reserves, are found in the Fort Union region of North Dakota. The coal seams in this region seldom dip more than a few degrees. Typically, the North Dakota lignite operations are surface mines designed to produce 2 million or more tons of lignite per year. Although a few specialized or older smaller mines remain in operation, the trend recently has been toward large-scale operations.

Reclamation and environmental issues are expected to affect Federal coal development in the Powder River basin, southern Wyoming, and the Fort Union region, For example, at Colstrip, Mont., fugitive dust levels presently exceed ambient air standards and future mine expansion will have to address and minimize air quality impacts. In southern Wyoming, where the climate is more arid, fugitive dust problems may have to be addressed at some mines, However, air quality concerns are not likely to deter Federal coal production significantly over the next 10 years in either the Powder River basin or southern Wyoming. Air quality is an important issue in the Fort Union region of North Dakota where the possible lack of sulfur dioxide ($S0_2$) increments may delay development of some leased Federal coal. These issues are discussed in more detail in chapter 10,

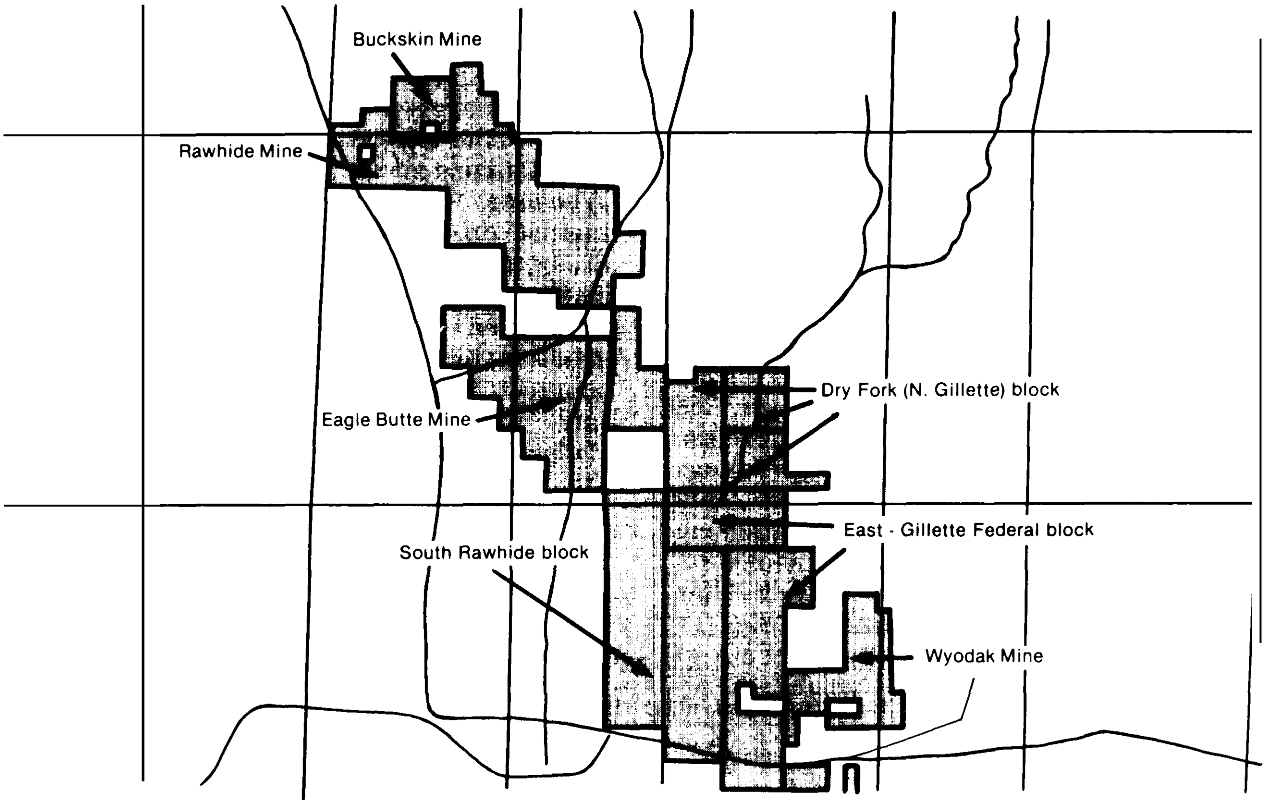
The availability of water and the impact of mining operations on water quality have not

Figure 28.— Federal Leases in the Hanna Basin, Southern Wyoming



SOURCE Off Ice of Technology Assessment.

Figure 29.—Federal Leases in the Powder River Basin, North of Gillette, Wyo.



SOURCE: Office of Technology Assessment.

generally been a major factor affecting coal mine development in the Powder River basin. However, such considerations could become important if onsite powerplants or synthetic fuels projects are extensively developed. Scarcity of water in the Gillette area of the Powder River basin, for example, justified the expense of constructing the first dry cooling tower in the United States at the Wyodak Power Plant. Competition for limited water supplies may ultimately affect the extent of coal mining in portions of southern Wyoming. In this area, mines need water for dust control and use in mining facilities and also for the irrigation of reclaimed lands.

Substantial quantities of topsoil, adequate rainfall, and a relatively flat terrain enhance the potential for successful reclamation in North Dakota. Nevertheless, reclamation efforts have not been uniformly successful in North Dakota. Mining in environmentally sensitive woody draws in the west-central region of the State has been delayed pending development of satisfactory reclamation plans, Reclamation efforts in North Dakota must also take into account sodic soil problems.

At present, Federal coal development in southern Wyoming and the Fort Union region affects no alluvial valley floors. In the Powder River basin, however, Federal coal production or expansion of Federal mine capacity could be affected in some cases if it is determined that adequate reclamation plans cannot be developed for alluvial valley floors, Of the 9.2 billion tons of Federal recoverable reserves under lease in the Powder River basin, approximately 700 million tons could be affected to some extent by alluvial valley floor considerations; less than 100 million tons of these may be prohibited from mining, however.

Although alluvial valley floors are not an important constraint on mine development in North Dakota, they are given careful consideration in mine permitting. Mining can be complicated in the Fort Union region because of large amounts of water that can seep into the mine pit. In cases where this seepage occurs through the highwall, there have been problems of instability and spoil pile slumping which cause inefficient and potentially dangerous mining conditions.

Concern about the protection of wildlife habitat has resulted in minimal prohibition to mining and production of Federal coal. In southern Wyoming, protection of raptor habitat has resulted in some changes in mining plans and has contributed to the loss of 5 million tons of reserves at one mine. Unless endangered species are found to reside on a proposed mine site, it is unlikely that significant amounts of recoverable reserves will be lost because of wildlife concerns.

Because most mines in the Powder River basin have large surface reserves, thick coal seams, and a low stripping ratio, Powder River basin coal is the cheapest coal to mine in the country. The capacity of a typical mine in the Powder River basin is larger than the capacity of most other surface mines located in the West and in other regions of the country, This high volume production and low production costs are well suited to long-term utility contracts. However, the heat content of Powder River basin coal is relatively low compared to coal produced in the Rocky Mountain coal province.

Electricity generation is the largest market for coal mined in Wyoming and Montana, with the main areas of demand in the South-Central and Midwest regions of the country. Demand for coal produced in Wyoming and Montana is expected to increase as demand for electricity increases in these regions. Conversions to coal-fired utility burners, particularly in the South-Central region, may further increase the demand for coal produced in the Powder River basin. Industrial demand for coal mined in the Powder River basin is expected to be relatively small over the next 10 years.

The availability, cost, and reliability of rail transportation to the Midwest and South-Central regions of the country are important factors in coal mine development in Wyoming and Montana. Transportation costs are already an important component of the delivered price of Wyoming and Montana coal, running as high as 70 percent in the Midwest (see table 28). Transportation costs are expected to rise still further over the next decade.

In general, leases in southern Wyoming and the Wyoming portion of the Powder River basin are closer to rail lines than leases in the Montana portion of the Powder River basin. Rail costs to the Midwest are lower for southern Wyoming coal than for Powder River basin coal; total delivered price on a per-Btu basis for southern Wyoming coal is competitive with Powder River basin coal in some areas, despite the higher mine-mouth cost of the southern Wyoming coal (see table 28).

Coal slurry pipelines could become an option for transporting coal from the Powder River basin over the next 10 years but development of slurry pipelines may be constrained by restrictions on water export. One slurry pipeline company, the Energy Transportation Systems, Inc. (ETSI) has obtained permission from Wyoming to export water. This pipeline is planned to have a capacity of 25 million tons per year. However, the State of Montana has decided that use of water for slurry pipelines is specifically not a beneficial use of water.

Lignite, which is mined in the Fort Union region, has a low-Btu value, high moisture content, and large concentrations of impurities. Consequently, the Federal coal mined in this region will generally be used close to the mine site. The characteristics of the lignite render its transportation both difficult and costly, requiring special hopper cars and special facilities for loading and unloading. Despite its poor quality, however, lignite has proved to be an acceptable fuel when used in properly designed, coal fired units. All powerplants currently planned or under construction in North Dakota will use lignite onsite.

Development Status of Federal Coal Leases in North Dakota, Montana, and Wyoming

There are 68 leases in 33 approved mine plans in the Federal coal regions of North Dakota, Montana, and Wyoming (table 48). These leases cover about 149,000 acres and contain 5.7 billion tons of recoverable reserves. Nearly 70 percent of the leases in currently approved mine plans in this three-State area (47 leases in 23 mine plans) are located in Wyoming. These Wyoming leases cover about 110,000 acres and include 4.7 billion tons of recoverable reserves. The Powder River basin of Wyoming contains 24 of these 47 leases in 12 mine plans on about 56,000 acres with 4.4 billion tons of recoverable reserves. Twelve leases in five approved mine plans are located in the Montana portion of the Powder River basin. These 12 leases cover over 29,000 acres and contain 0.8 billion tons of recoverable reserves.

Nine Leases are included in six pending mine plans in North Dakota and Wyoming. No leases are in pending mine plans in Montana. The five Wyoming leases in three pending mine plans will be analyzed with undeveloped leases.

Sixty leases not in mine plans are located in North Dakota, Montana, and Wyoming. The large majority of these undeveloped leases (47 leases, 26 blocks) are located in Wyoming. These Wyoming leases cover nearly 96,000 acres and contain 3.6 billion tons of

Table 48.—Acreage and Reserves Under Lease by Development Status

	Approved mine plans				Pending mine plans				No mine plans			
	Number Of leases	Number of plans	Acres	Recoverable reserves[a]	Number of leases	Number of plans	Acres	Recoverable reserves[a]	Number of leases	Number of blocks	Acres	Recoverable reserves[a]
North Dakota												
Fort Union	8	4	8,655	0.12	4	3	5,283	0.10	8	7	4,754	0.05
Total	8	4	8,655	0.12	4	3	5,283	0.10	8	7	4,754	0.05
Montana[b]												
Fort Union	**1**	**1**	**960**	**S**	**—**	**—**	**—**	**—**	**2**	**1**	**5,096**	**H**
Powder River basin	**12**	**5**	**29,252**	**<0.83**	**—**	**—**	**—**	**—**	**3**	**3**	**1,739**	**LM**
Total	13	6	30,212	0.83	–	–	–	–	5	4	6,835	0.37
Wyoming[c]												
Powder River basin	**24**	**12**	**55,681**	**4.4**	**4**	**2**	**9,599**	**0.53***	**30**	**16**	**67,185**	**3.4**
Hanna Field	**15**	**6**	**23,927**	**0.07**	**—**	**—**	**—**	**—**	**1**	**1**	**640**	
Rock Spring Field	**5**	**3**	**24,983**	**0.18**	**—**	**—**	**—**	**—**	**8**	**4**	**23,183**	**0.23****
Kemmerer Field	**3**	**2**	**5,602**	**S**	**1**	**1**	**1,408**	*****	**8**	**5**	**4,865**	**0.016**
Total	47	23	110,193	4.7	5	3	11,007	0.53	47	26	95,873	3.6
Totals	68	33	149,060	5.7	9	6	16,290	0.62	60	37	107,461	4.0

S = small reserves (zero to 30 million tons)
LM = low to medium reserves (30 million to 100 million tons)
HM = high to medium reserves (100 million to 180 million tons)
H = high reserves (over 180 million tons)

*Powder River basin reserves combined with Kemmerer Field reserves to preserve confidentiality.
**Hanna Field reserves combined with Rock Spring Field reserves to preserve confidentiality. Reserves for the Hanna Field lease are small

[a]In billions of tons.
[b]THREE SMALL LEASES IN THE BULL MOUNTAIN/YELLOWSTONE AREA ARE NOT LISTED IN THIS TABLE. THE LEASES COVER 240 ACRES AND HAVE VERY SMALL RESERVES. ONE LEASE IS IN A PRODUCING MINE. THE OTHER TWO ARE UNDEVELOPED LEASES.
[c]TWO SMALL LEASES IN THE BIGHORN BASIN ARE NOT LISTED IN THIS TABLE. THE LEASES COVER 200 ACRES, AND HAVE VERY SMALL RESERVES. BOTH ARE UNDEVELOPED.

SOURCE: Office of Technology Assessment.

recoverable reserves. Two-thirds of these leases (30 leases, 16 blocks) with 3.4 billion tons of recoverable reserves are located in the Powder River basin.

Leases With Approved Mine Plans and Leases in Pending Mine Plans*

Figure 30 shows the lessees' plans for capacity, total production, and production of Federal reserves from mines with Federal leases in North Dakota, Montana, and Wyoming. The dominance of the Powder River basin is apparent. Although coal production from Federal mines in each of these regions is expected to increase in the coming decade, the greatest increase is expected in the Powder River basin where, in 1986 total capacity and production of mines with Federal leases may be six times the total capacity and production of mines with Federal leases in southern Wyoming. Production of Federal reserves from these mines in the Powder River basin could be over 14 times that from Federal reserves in southern Wyoming in 1986. In 1991, the Powder River basin will continue to account for the largest capacity and production of coal from Federal mines in these three States and in all the Federal coal States.

Table 49 shows the acreage and recoverable reserves of Federal coal leases in approved mine plans in North Dakota, Montana, and Wyoming and pending mine plans in North Dakota. (The five leases in pending mine plans in Wyoming are not included in this table, because they are analyzed with undeveloped leases, below.) Total mine plan acres in this table refer to the total area permitted for mining as of early 1981. These data include Federal, State, and private surface areas used for mining activities and associated disturbances such as stockpiles, plant facilities, and buffer zones. Total mine plan acreage will change as mining operations expand to realize future production goals. The total mine plan acreage figures in table 49 do not include proposed amendments. However, amendments have already been submitted to the Office of Surface Mining for the expansion of mining activities at approximately 20 percent of the mines with Federal leases in Wyoming.

Federal lease acres refers to the surface acreage under which Federal coal is located. However, the Federal Government does not necessarily own all (or any) of the surface under which Federal coal lies. Thus, it is possible (and is indeed the case at the Caballo Mine in the Powder River basin) that the Federal Government could own no surface acreage in a mine plan even though most of the coal produced at the mine is extracted from Federal reserves. Moreover, not all the acreage of a Federal lease will necessarily be included in a mine plan.

Table 50 identifies the current and projected capacity and production, as reported by the lessees, for mines with Federal leases in North Dakota, Montana, and Wyoming. The portion of production that is expected from Federal reserves at these mines in the next 10 years is also included in table 50.

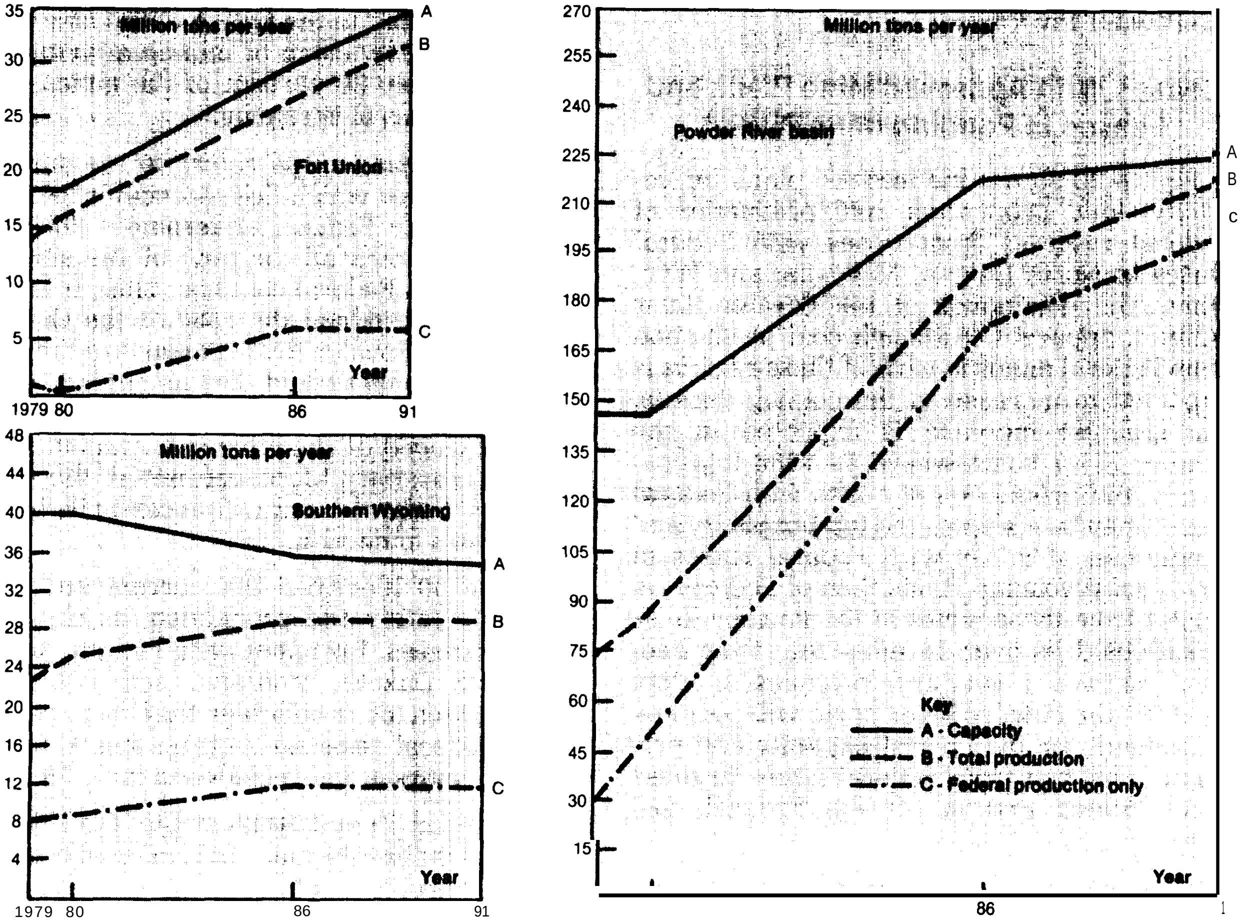
As tables 49 and 50 illustrate, the Powder River basin has the most Federal coal production, the greatest potential capacity, the most leased and permitted mine plan acreage, and the largest reserves of any of the major Federal coal regions studied in this report.

Powder River Basin

Twenty-four of the 36 leases in 12 of 17 approved mine plans in the Powder River basin are located in Wyoming; the remaining 12 leases in five approved mine plans are located in Montana. The large majority of reserves (over 80 percent) are located in the Wyoming portion of the Powder River basin as is the largest amount of recent and potential production. Production of coal from mines with Federal leases in the Wyoming section of the basin is expected to become more important during the next 10 years. The total capacity of mines with Federal leases in the

*Five leases in three pending mine plans in Wyoming are omitted from this section and are discussed in the section Undeveloped Leases, below.

Figure 30.—Lessee Projections of Capacity, Total Production, and Federal Production From Mines With Federal Leases: Fort Union Region, Powder River Basin, and Southern Wyoming
(leases in approved and pending mine plans only)[a]



[a]Five leases in three pending mine plans in Wyoming are not included In this figure They are considered with the undeveloped leases later in this chapter

SOURCE: Office of Technology Assessment.

Powder River basin is currently 3.7 times that of Federal mines in southern Wyoming and 8 times that of Federal mines in the Fort Union region.

The capacity of mines with Federal leases in the Powder River basin has not been fully used in recent years. In 1979, these mines could have produced 76 million tons more coal; in 1980, 60 million tons more coal. Mine capacity is expected to increase by nearly 50 percent between 1980 and 1986 (i.e., from 148 million to 220 million tons) and then remain relatively constant through 1991. This is because of the opening of several new large mines (e.g., Buckskin, Coal Creek, Rojo Caballos) and to the expansion scheduled for existing mines (e.g., Black Thunder, Eagle Butte, Rawhide). However, according to the production estimates of the lessees, the overcapacity of currently operating and permitted Federal mines in the Powder River basin will diminish to 15 percent in 1986 and to 3 percent in 1991.

Annual production from Federal reserves in the Powder River basin is becoming increasingly important, particularly in Wyoming. Federal reserves accounted for only 42 percent of total production from mines with

Table 49.—Summary of Mine Plan and Federal Lease Acreage and Recoverable Reserves: Approved and Pending Mine Plans in North Dakota, Montana, and Wyoming[a]

State/region	Number of leases	Number of mine plans	Total mine plan acres	Total Federal lease acres	Total mine plan reserves[b]			Federal mine plan reserves[b]			Total Federal lease reserves[b]		
					Underground[c]	Surface	Total	Underground[c]	Surface	Total	Underground[c]	Surface	Total
Approved													
North Dakota													
Fort Union	8	4	—	8,655	0	0.14	0.14	0	0.06	0.06	0	0.12	0.12
Montana													
Fort Union	1	1	—	960	0	s	s	0	s	s	o	s	s
Fort Union totals. . .	9	5	–	9,615	0	–	—	0	–	–	0	<0.15	<0.15
Montana													
Powder River basin ., ...	12	5	19,080	29,252	0	0.48	0.48	0	0.40	0.40	0	0.8	0.8
Wyoming													
Powder River basin	24	12	83,141	55,681	0	4.5	4.5	0	4.2	4.2	0	4.4	4.4
Powder River basin totals.	36	17	102,221	84,933	0	5.0	5.0	0	4.6	4.6	0	5.3	5.3
Southern Wyoming													
Hanna Field	15	6	57,037	23,927	LM	<0.2	-0.2	LM	LM	0.07	LM	LM	0.07
Rock Springs Field. ... ... , . .	5	3	66,227	24,983	LM	<0.4	0.4	Small	<0.18	0.18	Small	<0.18	0.18
Kemmerer Field . .	3	2	5,901	5,602	0	0.13	0.13	0	s	s	o	s	s
Southern Wyoming totals	23	11	129,165	54,512	LM	<0.7	0.7	LM	<0.3	0.3	LM	<0.3	0.3
Pending													
North Dakota													
Fort Union	4	3	–	5,283	Small	0.07	0.07	Small	0.02	0.02	Small	0.10	0.10

[a]THERE ARE TWO MINE PLANS WITH FEDERAL LEASES IN PRELIMINARY PERMIT REVIEW IN THE WYOMING POWDER RIVER BASIN, I.E. SOUTH RAWHIDE (1 LEASE) AND ANTELOPE (3 LEASES) AND ONE IN THE ROCK SPRINGS FIELD OF SOUTHERN WYOMING, I.E. , SOUTH HAYSTACK (1 LEASE) NO DECISION IS EXPECTED ON THESE PRELIMINARY REVIEWS UNTIL 1982 BECAUSE OF THE EARLY STAGES OF DEVELOPMENT OF THESE THREE MINE PLANS, DATA FOR THIS TABLE WERE UNAVAILABLE THESE LEASES ARE CONSIDERED IN THE FOLLOWING SECTION ON UNDEVELOPED LEASES

[b]In billions of tons.

[c]Underground mining occurs at the Vanguard #2 Mine in the Hanna Field. When strlppable reserves are depleted at this mine In 1984, underground operations will meet all contractual commitments even though underground reserves are small Underground mining also occurs at the Carbon #1 Mine in the Hanna Field The Stansbury Mine in the Rock Springs Field, closed early in 1981, was also an underground operation Stansbury may be reopened later in the decade

Key to reserve ratings:
S = small reserves (zero to 30 million tons)
LM = low to medium reserves (30 million to 100 million tons)
HM = high to medium reserves (100 million to 160 million tons)
H = high reserves (over 180 million tons)
NSR = no surface reserves

SOURCE Off Ice of Technology Assessment.

Federal leases in the basin in **1979.** By **1991,** Federal reserves will account for 92 percent of production from Federal mines averaged over the Powder River basin and almost 100 percent of production from Federal mines in the Wyoming section of the basin.

Southern Wyoming

Twenty-three Federal leases in eleven approved mine plans are located in southern Wyoming. These mine plans include over 129,000 permitted acres and contain 0.7 billion tons of recoverable reserves, of which only 0.3 billion are Federal. Recoverable reserves at three mines, Vanguard No. z, Carbon No. 1 and Stansbury,* are suitable for underground mining. The capacity of mines with Federal leases in southern Wyoming is expected to decrease 12 percent by the end of the decade, although production is expected to increase by 26 percent during this period. Utilization of capacity is expected to increase from 58 percent in 1979 to 83 percent in 1991. Federal reserves are expected to ac-

*Slansbury closed early in 1981 but is expected 10 reopen later this decade.

Table 50.—Federal Mine Capacity and Federal Mine Production Prospects: Approved and Pending Mine Plans in North Dakota; Approved Mine Plans in Montana and Wyoming[a]

	Number of mine plans with Federal leases	Number of Federal leases in these plans	1979[b] Federal mine capacity	1979[b] Actual Federal mine production	1979[b] Federal production only	1980[b] Federal mine capacity	1980[b] Actual Federal mine production	1980[b] Estimate of Federal production	1986[b] Projected Federal mine capacity	1986[b] Projected[e] Federal mine production	1986[b] Projected[e] Federal production	1991[b] Projected Federal mine capacity	1991[b] Projected[e] Federal mine production	1991[b] Projected[e] Federal production
North Dakota														
Fort Union(A)[c]	4	8	10	8.5	1.0	10	8.9	0.6	13	12	3	13	12	3
Fort Union(P)[d]	3	4	7	5.6	0	7	7.0	0	17	15	2	23	20	3
Montana Fort Union	1	1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fort Union totals	8	13	18	14	1.3	18	16	0.9	30	27	6	35	32	6
Montana Powder River Basin	5	12	36	27	8	36	25	10	52	46	29	52	49	31
Wyoming Powder River Basin	12	24	112	45	22	112	63	—f	169	144	142	175	170	170
Powder River Basin totals	17	36	148	72	30	148	88	–	220	191	171	226	219	201
Hanna Field	6	15	14	10.7	4	14	9.0	–	11	10	4	9	8	3
Rock Springs Field	3	5	19	7.2	4	19	10.4	—	18	13	7	19	15	7
Kemmerer Field	2	3	7	5.1	0.1	7	5.7	–	7	6	1	7	6	2
Southern Wyoming totals	11	23	40	23	8	40	25	—f	36	29	12	35	29	12

[a]Five leases in three pending mine plans in Wyoming are not included in this table. They are considered with the undeveloped leases in Table 53. There are no pending mine plans in Montana. One small mine in the Bull Mountain/Yellowstone region of Montana is not included in this table.
[b]All production and capacity estimates in millions of tons per year; totals may not add because of rounding. See second footnote on p. 114 for distinction between Federal mine and Federal production. Federal mine production includes Federal production.
[c]Approved mine plans.
[d]Pending mine plans.
[e]With few exceptions, these production pprotections are derived from lessees' mine plans.
[f]Total Federal coal production in Wyoming in 1980 was 33 million tons.

SOURCE: Office of Technology Assessment.

count for about 40 percent of production through 1991 in the Hanna Field; approximately 50 percent in the Rock Springs Field; and about 15 to 30 percent in the Kemmerer Field.

Fort Union Region

Nine leases in five approved mine plans are located in the Fort Union region of North Dakota and Montana. Eight of these leases in four approved mine plans located in North Dakota contain 0.12 billion tons of recoverable reserves. The one lease in an approved mine plan in Montana has small recoverable reserves.

In 1979, mine capacity for the North Dakota leases in approved and pending mine plans was 17 million tons per year; for the one Montana lease, only 300,000 tons per year. Annual production from these mines in 1979 was 14 million tons per year, of which about 1.3 million tons was from Federal reserves.

The contribution of Federal reserves to total production from mines with Federal leases in North Dakota is small because usually the Federal coal was leased in order to "fill out" a logical mining unit containing large amounts of non-Federal coal. Only 25 percent of the coal reserves in North Dakota are owned by the Federal Government—the lowest percentage of federally owned coal in the six major Federal coal States. Moreover, several Federal leases in North Dakota have either been mined out or are close to being mined out,

Most of the increase in total production and Federal production from Federal mines in North Dakota over the next decade is expected from mines currently in pending plans. By 1991 the capacity of mines with Federal leases in the Fort Union region is estimated at about 35 million tons per year. Total production could increase to 32 million tons per year, but production of Federal reserves will be a comparatively small proportion of this total (about 6 million tons).

Undeveloped Leases

Table 51 presents acreage and reserves information for the undeveloped leases in North Dakota, Montana, and Wyoming. The Wyoming portion of the Powder River basin contains 65 percent (nearly 77,000 acres) of the total acreage and contains over 85 percent (3,9 billion tons) of the recoverable reserves for the undeveloped leases located in these States. There are only about 80 million tons of underground recoverable reserves on undeveloped leases in these three States; all are located in southern Wyoming.

Assessing the Development Potential of Undeveloped Leases in North Dakota, Montana and Wyoming: Review of Property Characteristics

Environmental, transportation, and market factors were reviewed to assess the development potential of undeveloped leases in North Dakota, Montana, and Wyoming. However, before considering these factors, OTA reviewed information on the reserves, coal quality, and geologic features of these leases. This section summarizes the property characteristics of undeveloped leases in this three-State area. The review of the property characteristics of undeveloped leases emphasized the following four questions: 1) does the tract form a viable mining unit (i.e., is it compact and contiguous)? 2) does the tract have sufficient reserves to support an economical mine? 3) is the coal of suitable quality for current or potential markets (i. e., heat content

Table 51.—Acreage and Reserves of Undeveloped Leases:[a] North Dakota, Montana, and Wyoming

State/region	Total number of leases	Total number of lease blocks	Total Federal acres	Total[b] recoverable underground reserves	Total[b] recoverable surface reserves	Total[b] recoverable reserves
North Dakota	8	7	4,754	0	0.05	0.05
Fort Union	8	7	4,754	0	0.05	0.05
Montana	5	4	6,834	0	0.37	0.37
Fort Union	2	1	5,096	0	H	H
Powder River basin	3	3	1,739	0	LM	LM
Wyoming	52	29	106,880	0.08	4.1	4.1
Powder River basin	34	18	76,784	0	3.9	3.9
Hanna Field	1	1	640	0	S	S
Rock Springs Field	8	4	23,183	0.08	0.14	0.22
Kemmerer Field	9	6	6,273	very small	0.04	0.05
Totals	65	40	118,468	0.08	4.5	4.6

S = small reserves (zero to 30 million tons)
LM = low to medium reserves (30 million to 100 million tons)
HM = high to medium reserves (100 million to 180 million tons)
H = high reserves (over 180 million tons)
[a]INCLUDES FIVE LEASES IN THREE PENDING MINE PLANS IN WYOMING. SEE TABLE 48 FOR THE ACREAGE AND RESERVES OF THESE FIVE LEASES EXCLUDES FOUR SMALL LEASES, TWO IN WYOMING AND TWO IN MONTANA. SEE FOOTNOTES b AND c, TABLE 48.
[b]In billions of tons.

SOURCE: Office of Technology Assessment.

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not too low, sulfur and ash not too high)? and 4) are the coal seams sufficiently thick and, where surface mines are involved, is the ratio of overburden to seam thickness sufficiently low to be economically minable?

Powder River Basin and Southern Wyoming. —The following technical criteria were used in OTA's examination of the property characteristics of undeveloped leases in the Powder River basin and the coalfields of southern Wyoming.

There are three major uses for Western coal—offsite electric power generation, onsite electric power generation, and, potentially, synfuels production. For export steam coal in the Powder River basin and southern Wyoming, a mine needs to produce at least 1 million tons a year for a 30-year period. Thus, the minimum reserve requirement for a mine developed for export steam coal in these areas was set at 30 million tons.

Four million tons of annual production are generally required for 30 years (120 million tons of recoverable reserves) to supply an onsite electric generation plant (l,000 MW). Production of at least 6 million tons per year for 30 years (180 million tons of recoverable reserves) was set as the minimum requirement for the development of a mine for onsite synfuels production.

Because of high transportation costs, coal produced in these two regions for export out-of-State should have an average heat content of 8,000 Btu/lb for surface mines and 10,000 Btu/lb for underground mines. Coal with a lower heat content could be mined for onsite power generation or synthetic fuels production, but would be uneconomical to transport over any distance.

The 1970 and 1979 New Source Performance Standards (NSPS) for $S0_2$ were used as a basis for evaluating the sulfur content of coal in the Powder River basin and southern Wyoming. Generally, coal with less than 0.63 lb sulfur/million Btu will meet the NSPS without scrubbing, assuming 95 percent conversion of sulfur to SO_2. Sulfur content of less than 1.0 lb sulfur/million Btu will meet the 1979 NSPS requirement with partial scrubbing. Coal used onsite may have a higher sulfur level, but it should not exceed 2.0 lbs/million Btu in order to meet Wyoming's emission standard of 0.2 lb of $S0_2$ per million/Btu.

Ash is less critical than sulfur in the assessment of coal quality in Montana and Wyoming, but a high ash content can raise the cost per Btu of transporting coal to other States to an uneconomical level. Coal for export in the Powder River basin should have a maximum ash content of 10 percent; in southern Wyoming maximum ash content can be 12 percent since this coal usually has a higher heat content. Ash levels greater than 12 percent were considered acceptable for onsite conversion.

The seam thickness in existing mines in the Powder River basin ranges from 35 to 110 ft. Twenty ft was considered the minimum seam thickness for a developable property in the Powder River basin. The minimum seam thickness in southern Wyoming was set at 15 ft for surface mines and at 5 ft for underground mines.

Seam dip is not especially important in the Powder River basin since seams in this region are relatively flat. However, seam dip is an important factor in mine development in southern Wyoming where coal seams dip as much as 900. While surface mines can be developed with a seam dip up to 250, 13°, to 15° is considered the maximum seam dip for efficient coal recovery in underground mines.

Maximum average overburden thickness for coal mined in the Powder River basin is usually less than 130 ft. The maximum stripping ratio for this coal is usually 2.5. A maximum average overburden of 175 ft and a maximum average stripping ratio of 3.5 was considered acceptable for mines that will use coal onsite.

Fort Union Region.— Federal coal leases in the Fort Union region are rarely contiguous units or contiguous with one another. A single lease in the Fort Union region is often divided into several different tracts interspersed with fee coal. For this reason a company rarely acquires a Federal lease in North Dakota when it does not control the mining rights of the intervening coal property or lease sections. In addition, the minimum reserves required for mine development are rarely found in any one Federal coal lease. While this can and does occur in other States, in North Dakota it is the rule. Furthermore, variations in coal quality characteristics such as heat content are relatively unimportant in North Dakota because all the coal is of such quality that, in general, only development for use onsite or at a nearby facility is practical.

Limitations of Property Characteristics as a Measure of Development Potential.—Undeveloped leases with unfavorable property characteristics usually were found to have unfavorable development potential; similarly, leases with favorable property characteristics usually were found to have either favorable or uncertain development potential. However, in some cases other factors caused a different classification. Several illustrative examples are discussed below.

Lessee plans to incorporate the lease into an approved mine plan or existing mining operation.— In the Powder River basin, the Phillips Creek (1) lease block in Converse County, Wyo., has coal of low heat content and high ash content in thin seams. Nevertheless, it is adjacent to the Dave Johnston Mine which is scheduled to deplete its reserves in the late 1990's. The lease block was recently acquired by the Pacific Power & Light Co. (PPL) from SunEDCo and is likely to be integrated into the Dave Johnston logical mining unit. However, the Phillips (2) lease, recently acquired by the same lessee, and with similar poor property characteristics, is unlikely to be developed by itself and is unlikely to be integrated into an established mining operation.

Lessee plans to develop a synthetic fuels facility or onsite power generation.—Because of low heat content and high sulfur and ash, the Cherokee lease in southern Wyoming will probably not be developed to export coal to other States. However, the lease has sufficient reserves to support either an onsite synfuels project or electric generation plant. The site may eventually support both operations, since a synfuels project and a powerplant have been proposed by the lessee. The Cherokee lease, therefore, has favorable development potential contingent on the construction of a facility onsite to use the coal.

Lessee integrates the lease with non-Federal coal.—The two CX Ranch leases in the Montana portion of the Powder River basin both have small Federal reserves; without additional coal, neither of these leases would be likely to be developed. However, the lease held by Consolidation Coal Co. has been integrated with State and private fee coal already held by the company, and Consolidation is proposing an exchange of Indian coal for unleased Federal coal adjacent to the area. The transfer may be completed by the end of 1984. Because of these additional reserves, the lease has favorable development potential.

The other lease, held by Peter Kiewit Sons, Inc., also has been integrated with good quality fee coal and also has favorable development potential.

Other considerations.— Some undeveloped leases have unfavorable development potential even though they have excellent quality coal. For example, the Deadman lease includes some of the highest quality coal in the State of Wyoming; it has high heat content, low sulfur and ash, and adequate seam thickness. However, the Deadman lease lacks the reserve base needed to develop an economical new mining operation and is located in an area isolated from adequate transportation. Furthermore, underground mining operations required to develop this lease would be difficult because the seams on the lease dip as much as 250. For these reasons, the development potential of this lease is unfavorable despite high coal quality.

Results of Analysis of Development Potential

Table 52 summarizes the development potential of the 65 undeveloped leases (40 blocks) in North Dakota, Montana, and Wyoming. This total includes the 5 leases in pending mine plans in Wyoming which were analyzed as undeveloped leases. Thirty-eight leases (18 blocks) in this three-State area have favorable development potential. These leases contain 3.5 billion tons of recoverable reserves and cover over 69,000 acres. Eleven leases (eight blocks) in these States have uncertain development potential. These leases account for over 760 million tons of recoverable reserves and cover over 37,000 acres. Finally, 16 leases (14 blocks) in these States, covering over 11,000 acres have unfavorable development potential. However, the **310** million tons of recoverable reserves associated with these leases are less than 10 percent of the recoverable reserves contained on the 38 leases with favorable development prospects.

The Wyoming portion of the Powder River basin has the most reserves on undeveloped Federal coal leases in this area. The 3.9 billion tons of undeveloped recoverable Federal reserves in the Wyoming portion of the basin is nearly seven times larger than the combined undeveloped Federal reserves of southern Wyoming and the Fort Union region and about 40 times larger than the undeveloped Federal reserves in the Montana portion of the basin. Furthermore, less than 1 percent of the undeveloped reserves in the Wyoming portion of the Powder River basin have unfavorable development potential and over 80 percent have favorable development potential. The leases with unfavorable development potential in the Wyoming portion of the Powder River basin have poor property characteristics and little chance of being integrated with another coal property. The owners of the leases have given no indication that they will be developed. Two of the leases are authorized for trade under provisions of Public Law 95-554. * The undeveloped reserves in the Wyoming portion of the Powder River

*See ch. 9 for a discussion of exchanges.

Table 52.—Summary of Development Potential of Undeveloped Leases: North Dakota, Montana, and Wyoming[a]

	Favorable development potential				Uncertain development potential				Unfavorable development potential[a]			
State/region	Number Of leases	Number of lease blocks	Acres	Recoverable reserves[c]	Number of leases	Number of lease blocks	Acres	Recoverable reserves[c]	Number Of leases	Number of lease blocks	Acres	Recoverable reserves[c]
North Dakota	1	1	320	s	3	2	3,912	LM	4	4	522	S
Fort Union	1	1	320	s	3	2	3,912	LM	4	4	522	S
Montana	2	2	1,198	LM	1	1	541	LM	2	1	5,096	H
Fort Union	0	0	0	0	0	0	0	0	2	1	5,096	H
Powder River basin	2	2	1,198	LM	1	1	541	LM	0	0	0	0
Wyoming	35	15	67,627	3.5	7	5	33,425	0.67	10	9	5,828	S
Powder River[b] basin	24	10	43,690	3.2	6	4	32,178	0.66	4	4	916	S
Hanna Field	1	1	640	S	0	0	0	0	0	0	0	0
Rock Springs Field	5	2	18,951	H	0	0	0	0	3	2	4,232	S
Kemmerer field[b]	5	2	4,346	LM	1	1	1,247	S	3	3	680	S
Totals	38	18	69,145	3.5	11	8	37,878	0.76	16	14	11,446	0.31

[a]TWO SMALL UNDEVELOPED LEASES IN THE BIGHORN BASIN OF WYOMING AND Two SMALL UNDEVELOPED LEASES IN THE YELLOWSTONE/BULL MOUNTAIN AREA OF MONTANA HAVE BEEN OMITTED FROM THIS TABLE AND THE FOLLOWING DISCUSSION. THE LEASES HAVE VERY SMALL RESERVES AND UNFAVORABLE DEVELOPMENT POTENTIAL.

S = small reserves (zero to 30 million tons)
1 M = low to medium reserves (30 million to 100 million tons)
HM = high to medium reservs (100 million to 180 million tons)
H = high reserves (over 180 million tons)

[b]FIVE LEASES IN THREE PENDING MINE PLANS IN WYOMING (FOUR LEASES IN Two PENDING PLANS IN THE POWDER RIVER BASIN AND ONE LEASE IN THE KEMMERER FIELD) ARE INCLUDED IN THIS TABLE. ALL HAVE FAVORABLE DEVELOPMENT POTENTIAL. SEE TABLE 48 FOR THE ACREAGE AND RESERVES OF THESE LEASES.

[c]In bllions of tons

SOURCE: Office of Technology Assessment

basin represent a substantial pool of new coal production for the 1980's.

The three coalfields with Federal coal leases in southern Wyoming have 18 undeveloped leases (11 blocks), covering 30,000 acres and containing nearly 300 million tons of recoverable reserves. Less than 10 percent of these reserves, in six small leases with poor property characteristics, have unfavorable development potential.

Ten undeveloped leases are located in the Fort Union region. These leases cover 9,850 acres and contain over 0.3 billion tons of recoverable reserves. Two leases with unfavorable development potential in the Montana portion of the Fort Union region contain most of these reserves. Of the four leases with unfavorable development prospects in the North Dakota portion of the region, two were mined out before passage of the Surface Mining Control and Reclamation Act of 1977. Since no mine plan was submitted to the Office of Surface Mining they were classified as undeveloped. The lease with favorable development potential (located in the North Dakota portion of the Fort Union region) has very small reserves of leonardite, an oxidized form of lignite. Development of two of the three leases with uncertain development potential hinges on the availability of adequate transportation (see ch. 8).

Production Prospects for Undeveloped Leases With Favorable and Uncertain Development Potential

Table 53 summarizes the production prospects of undeveloped leases with favorable or uncertain development potential in North Dakota, Montana and Wyoming. Production from leases with unfavorable development potential is assumed to be zero through 1991.

Under favorable* market conditions, currently undeveloped leases in Wyoming, Montana, and North Dakota could produce nearly 78 million tons of coal in 1991. Nearly 65 million tons of this production, or over 80 per-

*See ch. 5 for a discussion of these conditions.

Table 53.—Summary of Production Prospects for Undeveloped Leases With Favorable or Uncertain Development Potential: North Dakota, Montana, and Wyoming

		Production prospects for 1986[a]				Production prospects for 1991[a]			
State/region	Leases/ lease blocks	Ranking[b] (number of leases/lease blocks)		Estimated mine capacity	Estimated production (millions of tons)	Ranking[b] (number of leases/lease blocks)		Estimated mine capacity	Estimated production (millions of tons)
North Dakota									
Fort Union	4/3	Favorable:	1/1	0.05	0.01	Favorable:	1/1	0.05	0.05
		Unfavorable:	3/2	0	0	Uncertain:	3/2	1.9	0 to 1.0
Montana									
Powder River basin	3/3	Uncertain:	1/1	7	0 to 1.6	Uncertain:	2/2	12	0 to 8.8
		Unfavorable:	2/2	4	0	Unfavorable:	1/1	0	0
Wyoming[c]									
Powder River basin	30/14	Favorable:	5/3	10.7	5.6 to 7.6	Favorable:	7/4	31	17 to 28
		Uncertain:	7/3	9	0 to 1.9	Uncertain:	8/4	38	0 to 28
		Unfavorable:	18/8	0	0	Unfavorable:	15/6	0	0
Hanna Field	1/1	Favorable:	1/1	0.6	0.4 to 0.6	Favorable:	1/1	0.6	0.3 to 0.6
Rock Springs Field	5/2	Favorable:	1/1	2	1.3 to 2.0	Favorable:	1/1	2	1.1 to 2.0
		Unfavorable:	4/1	0	0	Uncertain:	4/1	5	0 to 5.0
Kemmerer Field	6/3	Favorable:	5/2	3.5	2.2 to 3.5	Favorable:	5/2	4.5	2.6 to 4.5
		Unfavorable:	1/1	0	0	Unfavorable:	1/1	0	0

[a]Leases with unfavorable development potential are not included in this table because such leases necessarily have unfavorable production prospects for 1986 and 1991.

[b]Ranking refers to production prospects for 1986 or 1991. Some leases with favorable or uncertain development potential may have uncertainties surrounding their being in production by 1986 or 1991, or may be unlikely to be in production until after 1986 or 1991. Such leases have uncertain or unfavorable production prospects for 1986 or 1991.

[c]Figures include five leases in three pending mine plans: four leases in two pending mine plans in the Powder River basin and one lease in one pending mine plan in the Kemmerer Field.

SOURCE: Office of Technology Assessment.

cent, could come from the Powder River basin. Under weak market conditions, production from currently undeveloped leases in the three-State area is likely to be only about 21 million tons in 1991, with about 17 million tons (81 percent) coming from the Powder River basin.

The wide range of 17 million to 65 million tons in estimated production from Powder River basin undeveloped leases in 1991 is caused by demand uncertainty. Delivery of 17 million tons of coal in 1991 from presently undeveloped leases in the Powder River basin has been contracted for; markets would have to be developed for the rest. All leases with uncertain development potential in the Powder River basin have unfavorable production prospects for 1986 and 1991 (see ch. 7).

In southern Wyoming, production from 12 presently undeveloped leases is estimated to range between 4 million and 12 million tons by 1991. The lower production could be achieved by 1986; much of the remainder depends on the pace of development of a planned synfuels facility. Presently undeveloped leases will be the only source of new Federal mine capacity in southern Wyoming.

A Federal mine containing a small leonardite lease in North Dakota may be producing 50,000 tons per year by 1991, and one lease block in North Dakota with uncertain development potential because of transportation uncertainties may be producing up to 1 million tons per year by 1991.

Diligence

Diligent Development Analysis

The Mineral Leasing Act of 1920 provides that each Federal coal lease is held subject to the conditions of diligent development and continuous operation. In 1976, DOI issued regulations defining diligent development for Federal coal leases as actual production of coal in commercial quantities from the lease or from the logical mining unit (LMU) of which the lease is a part by June 1, 1986 or within ten years after the lease is issued, whichever is later. Leases that do not meet this minimum production requirement can be canceled. Under certain conditions, the period for producing the minimum amount for achievement of diligence can be extended for up to 5 years to June 1, 1991, for leases issued before passage of FCLAA.

Enforcement of DOI's diligent development requirements for pre-FCLAA leases is an important issue in the management of existing leases, not only because of the controversy involving the applicability of the regulations, but also because of the potential administrative requirements on DOI in handling requests for extensions or approvals of enlarged LMUS, and cancellations. Moreover, after 1986, new Federal leases cannot be issued to any lessee, including a pre-FCLAA lessee, who is holding a lease from which he has not produced coal in commercial quantities during the previous 10 years,

OTA made a rough comparison of its estimates of future production from Federal leases with DOI's diligent production requirements to determine: 1) how many leases are likely to meet diligence by 1986, and 2) assuming that extensions were granted in many cases under the existing guidelines, the likelihood for other leases meeting diligence by 1991. The following sections summarize briefly the results of OTA's diligence analysis. See chapter 9 for a description of the issues related to current diligent development regulations.

Comparison of Production From Federal Leases and Diligent Development Requirements

OTA compared the planned and estimated production from existing Federal leases with the minimum production requirements set by the 1976 DOI regulations defining diligent development for pre-FCLAA leases. The analysis covered the 502 leases in the Southern Rocky Mountain and Northern Great Plains regions including about 30 post-FCLAA leases issued as production maintenance, hardship, or bypass leases associated with active mines. * Almost all of these post-FCLAA leases will meet diligence as part of the larger mining operations,

OTA used mine plan data and information from mine operators and Government agencies. Each approved or pending mine plan or each undeveloped lease block was considered to be an approximate logical mining operation. (The term approximate logical mining operation was used so as not to confuse mine plan and lease block units with designated or approved LMUS as defined by DOI regulations.) In assessing a lessee's prospects for meeting diligence, OTA used the Federal mine production estimates presented earlier, In deriving these production estimates, OTA considered many variables that could, in turn, affect the lessee's ability to meet diligence, such as the amount and quality of reserves, mine type, transportation availability, and present and projected coal demand (see ch. 2 of this report for further discussion of the methodology used in reaching production estimates).

In conducting this analysis, OTA made the following assumptions:

1. The mining operations will meet the mine plan production schedules or, if no mine plan is available, the mining operations will meet OTA's estimated production schedule. OTA estimated the earliest feasible year for commercial production for leases without plans.
2. The reserves and production from the approximate logical mining operations (either the total mine plan area or the Federal lease block) were used in assessing prospects for meeting diligence. Mines were presumed to meet diligence for all Federal leases in the unit if they produced at least 2½ percent of the total mine plan reserves by 1986 or 1991. (Without detailed information on the mining sequence and geometry for each mine, OTA was not able to calculate compliance on a lease by lease basis).
3. All leases with planned production and those undeveloped leases with favorable or uncertain development prospects that are likely to start producing in 10 years were assumed to receive extensions of the diligence period to 1991 if they did not produce enough to meet diligence by 1986. Under current diligence guidelines, some mines, particularly small- and medium-sized underground operations producing under 2 million tons per year, might have difficulty qualifying for extensions. Nevertheless, it was assumed for purposes of this analysis that they would be able to negotiate an extension. OTA estimates that the number of new mines and leases that are likely to be producing by 1991 and that could not qualify for an extension under a broad interpretation of the diligence guidelines is very small,

*See the Oklahoma section at the end of this chapter for a discussion of diligence prospects for Oklahoma leases.

The results of OTA's analysis for leases in the six major Western Federal coal States are described in the following sections.

Diligent Development in Colorado, New Mexico, and Utah

Southern Rocky Mountain region States (Colorado, New Mexico, and Utah) have 360 Federal coal leases. Over 60 percent (221 leases) of the leases in this region are included in currently approved or pending mine plans. Of the remaining 139 leases without mine plans, OTA's analysis identified 96 leases that potentially could be producing by

1991. The results of OTA's diligence analysis are summarized in table 54 and figure 31. The analysis shows that by 1986, all 113 of the leases in approved mine plans, 22 leases in pending mine plans and one undeveloped lease will probably have satisfied the production requirements for diligence. By 1991 another 110 leases could possibly meet diligence, assuming that the lessees receive extensions to the diligence period. A total of 246 leases, (68 percent of the leases) with 73 percent of the Federal lease reserves in the Southern Rocky Mountain region could meet, or surpass, the production requirements for diligence by 1991.

The percentages of leases and reserves in each diligence category are relatively evenly distributed for the region as a whole (see fig. 31), however, there is much less correspondence between reserves and leases meeting diligence when these percentages are calculated on a State basis, as shown in figure 32.

In Colorado, about 80 percent of the leases and 93 percent of the lease reserves could possibly meet diligence; however, half of the reserves contained in only 26 percent of the leases are uncertain to meet diligence because of uncertainties in the pace and scale of proposed development. The 19 percent of the leases in Colorado that are unlikely to meet diligence contain only 7 percent of the Federal lease reserves.

In New Mexico, nine leases, 31 percent of the leases in the State, are unlikely to meet diligence. These leases, however, contain less than 1 percent of the Federal lease reserves. Thus, in New Mexico, 69 percent of the leases with over 99 percent of Federal reserves under lease are expected to meet diligence.

In Utah, about 40 percent of the leases in the State and 44 percent of the lease reserves are unlikely to meet diligence by 1991. Most of the lease reserves (1.4 billion tons) in Utah that will not meet diligence are contained in 61 leases on the Kaiparowits Plateau that could be producing by 1991 but which are unlikely to do so and, in any event, will not have produced enough to meet diligence by 1991. Most of the leases and reserves in active, proposed, or potential new mines in central Utah (95 leases—roughly 46 percent of leases and reserves in the State) will probably achieve diligence by 1991.

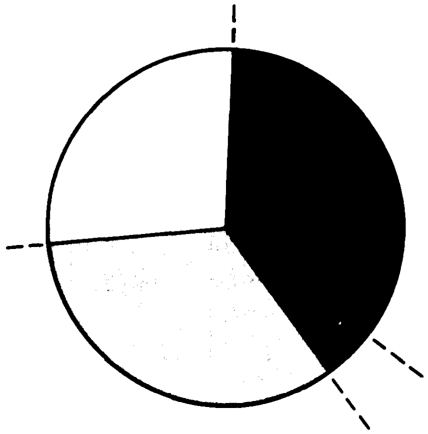
Table 54.—Analysis of Prospects for Meeting Diligent Development Requirements by 1986 or 1991: Federal Leases, Mining Units, and Recoverable Reserves in Colorado, New Mexico, and Utah
(all reserves in millions of tons)

				Likely to achieve diligence by 1986			Likely to achieve diligence by 1991			Uncertain to achieve diligence by 1991			Unlikely to achieve diligence by 1991		
State	Number of leases	Number of mining units	Recoverable reserves	Number of leases	Number of mining units	Recoverable reserves	Number of leases	Number of mining units	Recoverable reserves	Number of leases	Number of mining units	Recoverable reserves	Number of leases	Number of mining units	Recoverable reserves
Colorado	127	66	2,234	64	25	871	6	3	71	33	19	1,133	24	19	157
Approved plans	54	19	724	54	19	724	0	0	0	0	0	0	0	0	0
Pending plans	21	11	455	9	5	142	6	3	71	5	2	241	1	1	0
No plans	52	36	1,055	1	1	6	0	0	0	28	17	892	23	18	157
New Mexico	29	15	447	17	4	314	1	1	38	2	2	93	9	8	2
Approved plans	9	2	169	9	2	169	0	0	0	0	0	0	0	0	0
Pending plans	9	3	183	8	2	145	1	1	38	0	0	0	0	0	0
No plans	11	10	95	0	0	0	0	0	0	2	2	93	9	8	2
Utah	204	56	3,253	55	17	835	8	4	206	60	12	773	81	23	1,439
Approved plans	50	14	792	50	14	792	0	0	0	0	0	0	0	0	0
Pending plans	78	11	1,270	5	3	42	8	4	206	29	2	351	36	2	671
No plans	76	31	1,191	0	0	0	0	0	0	31	10	423	45	21	768
Total region	360	137	5,934	136	46	2,020	15	8	315	95	33	2,000	114	50	1,598
Approved plans	113	35	1,685	113	35	1,685	0	0	0	0	0	0	0	0	0
Pending plans	108	25	1,907	22	10	329	15	8	315	34	4	597	37	3	671
No plans	139	77	2,341	1	1	6	0	0	0	61	29	1,408	77	47	927

NOTE: Reserves columns may not add to totals because of independent rounding.

SOURCE: Office of Technology Assessment.

Figure 31.— Diligent Development Summary for the Southern Rocky Mountain Region (percent of reserves)



Key	Number of leases	Percent of leases	Reserves[a]	Percent of reserves
Likely to meet diligence by 1986	136	36	2.0	34
Likely to meet diligence by 1991	15	4	0.3	5
Uncertain to meet diligence by 1991	95	26	2.0	34
Unlikely to meet diligence by 1991	114	32	1.6	27

[a]Billions of tons.

SOURCE: Office of Technology Assessment

Leases That Are Likely To Meet Diligence by 1986

In the Southern Rocky Mountain States, **136** leases with a total of **2** billion tons of Federal reserves—about 34 percent of the Federal reserves under lease in the region— are likely to have met diligence by 1986. All of the mines are expected to meet continuous operations requirements and to be mined out within 40 years at planned production rates.

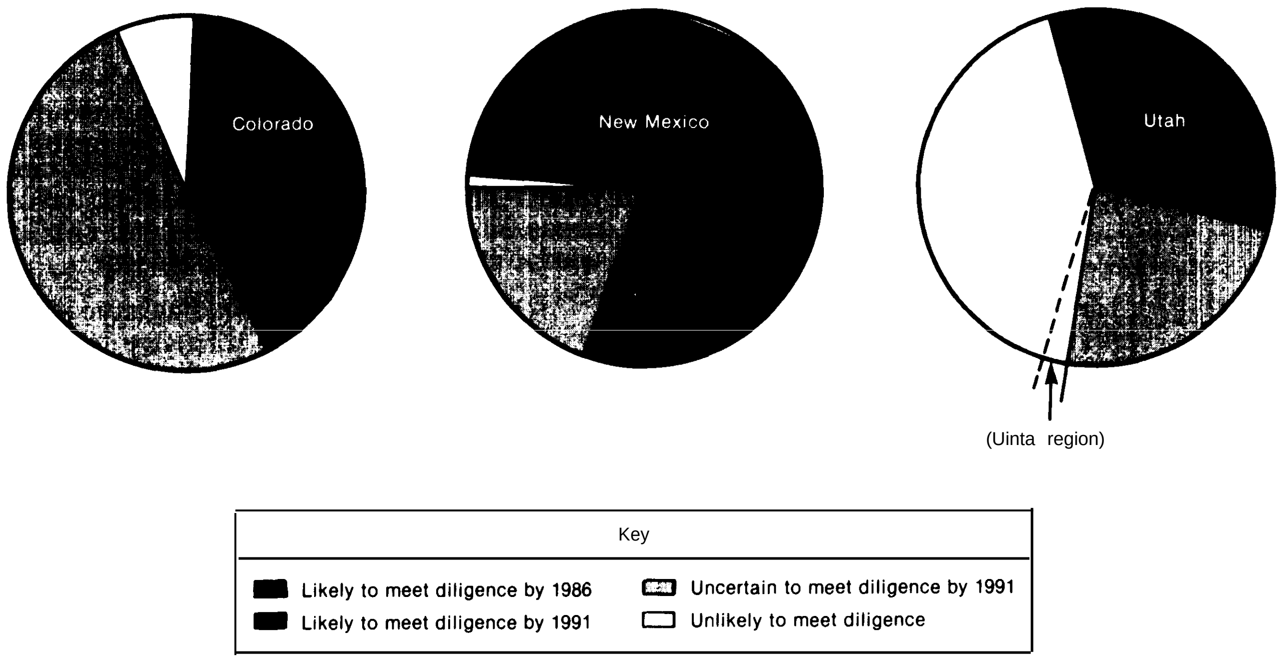
According to projected production schedules contained in the mine plans, all of the 113 leases included or associated with the 35 mines with approved mining plans will have met diligence for the total mine plan reserves by June 1, 1986. Many, if not most, of these mines have already produced this amount and many of the individual leases have, in fact, already produced enough to meet diligence. In those cases where leases have not produced the minimum amounts by 1986, the lessees could either request extensions or approval of enlarged LMUs combining both currently producing and nonproducing mine areas so that aggregate production can be used to meet the diligence requirement.

Another 22 leases in 10 pending mine plans are also likely to achieve diligence by 1986 according to mine plan production schedules. One currently undeveloped lease in Colorado is expected to begin production before 1986 and thus, will meet diligence. It is possible that other undeveloped leases could achieve diligence by 1986 by inclusion with DOI approval in adjacent active mining units owned by other lessees through assignment or operating agreements. This would involve fewer than 10 leases in the Southern Rocky Mountain region because of the requirement that all areas in an approved LMU must be contiguous.

Leases That Are Likely To Meet Diligence by 1991

By 1991, 15 more leases in eight mines with a total of 315 million tons of Federal lease reserves are expected to meet diligence requirements. These eight mines, including six leases in Colorado, one in New Mexico, and eight in Utah, represent 4 percent of the leases and 5 percent of Federal coal reserves in the region. All of these leases are in proposed mine plans currently under review. At least three mines are not scheduled to begin commercial production until 1986 or later. The eight mines include two small mines that are being reopened on previously mined leases, one new, large surface mine, and one mine that would combine surface and underground recovery methods. Another mine is a captive operation that would supply a new powerplant that has been delayed, and still one other has been suggested by proponents as one of the suppliers for a proposed coal gasification plant in Utah. The remaining two

Figure 32.- Diligent Development Summary for Federal Lease Reserves in Colorado, New Mexico, and Utah[a]



[a]See table 54 for amount of reserves.

SOURCE: Office of Technology Assessment.

mines are underground operations that will sell to utilities and industrial users.

Leases That Are Uncertain To Meet Diligence by 1991

OTA found that 95 leases in 35 approximate logical mining operations with about 2 billion tons of recoverable Federal reserves may not meet diligence requirements by 1991. Roughly 26 percent of the leases and 34 percent of the leased reserves in the Southern Rocky Mountain region could possibly achieve diligence by 1991; however, OTA found that these leases face some uncertainties regarding the pace or scale of proposed mining activities or in defining the LMU reserves. There are several reasons why some of these leases might not meet diligence: The date of initial production for some mines is uncertain because of delays in construction of associated electric powerplants or transportation systems. For several lease tracts with very large underground reserves in multiple seams, it is difficult to predict how many seams will eventually be included in the LMU reserves, since that determination will, in part, depend on the sequence of mining. Perhaps the greatest uncertainty is that the development plans of several lessees with large tracts of good quality minable reserves have not yet been announced. Production from captive mines that are planned as replacement capacity for existing operations is dependent on exhaustion of the economically recoverable reserves in existing mines. In some cases, the new captive mines are not contiguous with the existing operations, so they could not be combined with producing mines to meet diligence under current law.

Utah has 60 leases that are uncertain to meet diligence by 1991 including 28 leases in the proposed Alton surface mine with over 200 million tons of recoverable Federal reserves. The Alton Mine alone contains one quarter of all the leases and 30 percent of the reserves that are uncertain to meet diligence in the three-State area. The difficulties in Alton's proposed development plans are discussed earlier in the chapter and in the Utah appendix.

Colorado has 33 leases in 18 units that might not meet diligence, including two pending mine plans. One of these, Arco's Mt. Gunnison Mine, has a large amount of recoverable reserves in multiple seams, It is possible that the logical mining unit reserves could be defined by the U.S. Geological Survey as less than the total reserves by including only the seams commonly mined in the region. If so, the mine could meet diligence by 1991, and perhaps, even by 1986, since at least one lease in the mine has already produced coal,

Leases That Are Unlikely To Meet Diligence by 1991

Nearly one-third of the leases in the Southern Rocky Mountain States, 114 leases, with 1.6 billion tons of Federal reserves in 60 mining units, are unlikely to achieve diligent development. These include 37 leases that are in three proposed new mine plans—one small mine in Colorado and two mine complexes on the Kaiparowits Plateau in Southwestern Utah. Sixty-eight leases that are unlikely to meet diligence by 1991 are located in southwestern Utah. A total of 61 Kaiparowits leases in six blocks with 1.4 billion tons of reserves have some potential for development according to OTA's analysis, But even if the lessees began production by 1987 (probably the earliest feasible date), it is unlikely that they would be able to produce enough to meet diligence by 1991 because of the large amount of reserves involved. Moreover, it is unlikely that a new coal transportation system connecting Southwestern Utah with potential markets will be operational by 1991. The remaining 53 leases in the three-State region are unlikely to meet diligence because they are unlikely to be mined in the next decade. These nonproducing leases include many abandoned small mines and other leases that do not have enough good quality minable reserves to sustain viable independent mining operations and are not located adjacent to other active mines.

Diligent Development in North Dakota, Montana, and Wyoming

The results of the analysis on diligent development are summarized in table 55 for the coal regions of Wyoming, Montana, and North Dakota. Figure 33 summarizes the results for the Powder River basin, The first diligence requirement (production of 21/z percent of LMU recoverable reserves by 1986/ 1991) is the only one summarized in the table; with few exceptions, LMUs which are likely to meet this requirement appear likely to meet the additional requirement of continuous operation and appear likely to be mined out in 40 years.

The diligent development analysis for Wyoming, Montana, and North Dakota has reached the following conclusions:

1, Over 60 percent of the leases containing nearly 70 percent of the reserves under Federal lease in these three States are likely to either meet diligence in 1986 or in 1991,
2. For the Powder River basin, demand for coal is the dominant factor in whether leases containing about 1.2 billion tons of recoverable reserves will meet diligence by 1991.
3. Over 90 percent of the 1.5 billion tons of recoverable reserves contained in leases unlikely to achieve diligence by 1991 in the Powder River basin are suitable only for onsite synfuels development; and nearly 40 percent (0.6 billion tons) are suitable only for in situ gasification, assuming that technology is developed.
4 For southern Wyoming, leases containing most of the reserves should meet diligence by 1986 under expected market conditions, The principal uncertainty in whether leases containing essentially all of the reserves will meet diligence by 1991 is the pace of development of a synfuels project.

Table 55.—Diligent Development Summary

State/region	Total number of leases/ lease blocks	Total Federal lease recover- able reserves (billions of tons)	Likely to achieve diligence by 1986	Likely to achieve diligence by 1991	Uncertain whether will achieve diligence by 1991	Unlikely to achieve diligence by 1991: Favorable or uncertain development potential	Unlikely to achieve diligence by 1991: Unfavorable development potential
North Dakota Fort Union	20/14	about 0.6[b]	about 0.2[b] (12/7)[c]	S (1/1)	LM (3/2)	—	S (2/2)
Montana Fort Union	3/2	—[b]	—[b] (1/1)	—	—	—	H (2/1)
Total Fort Union	23/16	about 0.6[b]	about 0.2[b] (13/8)[c]	S (1/1)	LM (3/2)	—	H (4/3)
Montana - Yellowstone & Bull Mountain	3/3	S	S (1/1)	—	—	—	S (2/2)
Montana Powder River basin	15/8	0.9	0.8 (12/5)	—	<0.1 (2/2)	<0.1 (1/1)	—
Wyoming Powder River basin	58/30	8.3	4.0 (27/13)	1.7 (8/4)	1.2 (8/4)	1.5 (1 1/5)	S (4/4)
Total Powder River basin	73/38	9.2	4.8 (39/18)	1.7 (8/4)	1.2 (10/6)	1.5 (12/6)	S (4/4)
Wyoming Big Horn basin	2/2	S	—	—	—	—	S (2/2)
Wyoming Hanna Field	16/7	0.07	0.07 (16/7)	—	—	—	—
Wyoming Rock Springs Field	13/7	0.4	>0.2 (5/3)	<0.2 (1/1)	<0.2 (4/1)	—	S (3/2)
Wyoming Kemmerer Field	12/8	0.06	>0.03 (4/3)	<0.03 (4/1)	—	S (1/1)	S (3/3)
Total Southern Wyoming	41/22	0.5	>0.3 (25/13)	<0.2 (5/2)	<0.2 (4/1)	S (1/1)	S (6/5)

Key to table:
1) All reserves are in billions of tons.
2) All reserves are Federal reserves under lease; LMU reserves, if they include non-Federal coal are larger.
3) "Likely (uncertain, unlikely) to achieve diligence by 1986 (1991)" refers to likelihood that 2½ percent of LMU reserves will be produced by 1986 (1991).
4) In columns 4 through 8, the upper number in each row is Federal reserves under lease; e.g., in the Montana portion of the Powder river basin, 0.8 billion tons of Federal reserves under lease are likely to meet diligence by 1986.
5) In columns 4 through 8, the lower set of numbers in each row is number of leases/number of lease blocks; e.g., in the Montana portion of the Powder River basin, 12 leases in five lease blocks are likely to meet diligence by 1986.

[a]These leases generally have poor development potential because of small reserves, low coal(quality and difficult mining conditions,
[b]Reserves in the Montana and North Dakota portions of the Fort Union region have been combined to preserve confidentiality.
[c]In addition, two leases were mined out before the passage of SMCRA. Because no mine plans were filed for these leases they were classed as undeveloped. Because no further production will occur from the leases, they have unfavorable development potential. However, because their reserves have been mined out, they have met diligence already.

S = small reserves (zero to 30 million tons)
LM = low to medium reserves (30 million to 100 million tons)
HM = high to medium reserves (100 million to 180 million tons)
H = high reserves (over 160 million tons)

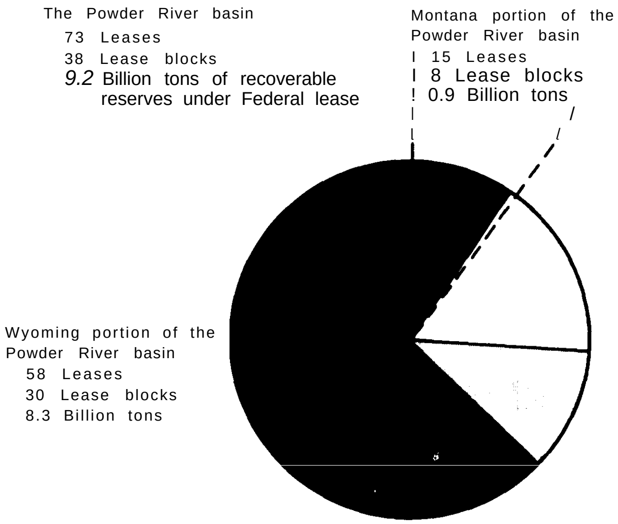
SOURCE: Office of Technology Assessment.

5. In the Fort Union region, all leases in approved and pending mine plans (with about 40 percent of the Federal reserves under lease in the region) are likely to meet diligence by 1986. However, only one very small undeveloped lease is likely to meet diligence even by 1991. Adequate transportation constitutes an uncertainty in whether two other leases will meet diligence by 1991.

Powder River Basin

As table 55 and figure 33 indicate, there are 73 leases in 38 lease blocks in the Powder River basin of Wyoming and Montana. Federal reserves under lease total 9.2 billion tons in the Powder River basin, of which 10 percent, or 900 million tons, are in the Montana portion. Seventy percent of the recoverable reserves under lease in the Powder River basin, or 6.5 billion tons, are likely to meet

Figure 33.— Diligent Development Summary for the Powder River Basin



Key	Reserves*	Percent of reserves
Likely to achieve diligence by 1986:	4.8	52%
Likely to achieve diligence by 1991:	1.7	18%
Uncertain whether will achieve diligence by 1991:	1.2	13%
Unlikely to achieve diligence by 1991:	1.5	16%

*Billions of tons.

SOURCE: Office of Technology Assessment.

diligence by 1986 or 1991. Thirteen percent, or 1.2 billion tons, are uncertain to achieve diligence by 1991 and 16 percent, or 1.5 billion tons, are unlikely to achieve diligence by 1991,

With two exceptions, the 18 lease blocks in the Powder River basin likely to achieve diligence by 1986 are associated with producing mines or are in approved mine plans. With one exception, all these lease blocks presently have contracts to deliver coal by 1986 or earlier. * Of the four lease blocks** likely to achieve diligence by 1991 but not by 1986, only South Rawhide does not presently have contracts for coal delivery before 1991. (Contracts are one of the criteria for granting diligence extensions).

The six lease blocks*** which are uncertain to achieve diligence by 1991 are all undeveloped; none of them presently has contracts for 1991. However, all the lease blocks have favorable development potential, and the lessees are working to develop their properties. Applications for extensions to diligence are expected to be filed for all of these blocks. Five of the six lease blocks are being planned as large surface mines, with capacities of 5 million tons per year or more, and would thus probably qualify for a diligence extension under the second (large mine) extension criterion. The sixth has a planned capacity of 4 million tons per year. However, the level of demand for Powder River basin coal is an important factor in their achieving diligence. If demand in 1991 is at the OTA high demand scenario level of 275 million tons per year, all of these lease blocks would likely meet diligence by 1991. However, if demand in 1991 is at the OTA low demand scenario level of 163 million tons per year, it is possible that none of these lease blocks will even go into production by 1991. (See ch. 7 for a description of the OTA high and low demand scenarios for Powder River basin coal.)

Six undeveloped lease blocks are unlikely to achieve diligence by 1991 even though they do not have unfavorable development potential. Production on four of these (Lake deSmet, Bass Trust, Belco, Gulf [l&z)) is contingent on synfuels development; for three of the four, production is contingent on in situ gasification development. Although little development activity has occurred on the fifth

*PPL is conductng a feasibility study to determine whether or not its Philllps Creek (1) leases should be integrated with the Dave Johnston Mine. According to a company spokesman, the leases are likely to be added to the mine, in which case, even though the leases themselves are unlikely to be mined until 1991 or later, they would meet diligence as part of the logical mining unit. North Antelope Coal Co, 's North Antelope lease does not yet have an approved mine plan but has a contract for 1984 delivery of coal.

**South Rawhide, Rochelle, Antelope, Rojo Caballos. In the case of South Rawhide. the lessee may blend its coal with the output from the existing Rawhide and Caballo Mines, reducing production at these two mines, if contracts cannot be obtained for South Rawhide itself. Diligence could then be achieved for all three mines: for Rawhide and Caballo by 1986: for South Rawhide by 1991.

***Dry Fork, East Gillette Federal, N. Rochelle, CX Ranch (Consol), CX Ranch (PKS), Wildcat.

(East Wyodak), the lessee (Peabody) has strongly stated its intent to develop the property. The sixth lease, Pearl, is in Montana. The lessee, Shell, spent considerable sums on development, including the preparation of an environmental impact statement, before suspending activity. Shell declares it will resume development once markets strengthen. All six are expected to file for diligence extensions. Finally, four undeveloped lease blocks with unfavorable development potential are unlikely to meet diligence.

Southern Wyoming

As table 55 states, there are a total of 41 leases in 22 lease blocks in the three coalfields of southern Wyoming. These leases contain over 500 million tons of recoverable reserves. Leases containing over 300 million tons of reserves are likely to achieve diligence by 1986 and several mines are likely to meet diligence by 1991. The lease block whose achievement of diligence is uncertain for 1991 is being planned for synfuels.

Development Potential and Production Prospects of Federal Coal Leases in Oklahoma

There are 46 Federal coal leases located in the Oklahoma portion of the Western Interior coal region; the region also includes the States of Arkansas, Kansas, Missouri, and Iowa. There are no Federal coal leases in the latter four States. Total coal production in Oklahoma in 1979 was 5 million tons, or 40 percent of total Western Interior production and over three times the total production of the State a decade ago. However, Federal reserves accounted for only 0.3 million tons of Oklahoma production in 1979.

Approximately 80 percent of the leased Federal coal in Oklahoma is of high metallurgical quality that is used primarily to produce coke for domestic steel production. Virtually all of the increase in Oklahoma coal production over the last 10 years has been noncoking coal. Although metallurgical grade coal can be blended with steam coal to generate electricity, it is unlikely that any new mines with Federal leases in Oklahoma will be developed to sell metallurgical quality coal primarily for blending for steam-electric generation. Weak demand is expected for metallurgical quality coal over the next 10 years. Captive mining operations, where the parent company produces steel or cement, and sales to foreign buyers appear to be the main source for Federal coal development in Oklahoma throughout the 1980's.

Status and Production Prospects of Leases in Approved Mine Plans in Oklahoma

There are seven leases in five approved mine plans in Oklahoma (see table 56). One of the seven leases was relinquished in 1980 because of the increase in royalty at the time of readjustment. Production on another lease has been interrupted because of labor disputes. The reserves remaining on this lease can support less than 5 years of commercial production. The remaining five leases in approved mine plans or associated with operating mines are currently producing coal or are scheduled to produce coal in the near future. However, only two of these leases in one mine plan are expected to produce coal continuously over the next 10 years. These two leases are likely to meet diligence by 1986 or 1991. Of the remaining three leases in approved mine plans, the reserves on one are expected to be depleted by 1984, and the reserves on the other two by 1986.

Status and Development Potential of Undeveloped Leases and Leases in Pending Mine Plans in Oklahoma

Thirty-eight leases (20 blocks) of the 46 leases in Oklahoma are not included in mine

Table 56.—Status and Development Potential of Undeveloped Leases in Oklahoma

Status of leases
Approved mine plans:
7 leases
5 mine plans
8,668 acres
6 million tons recoverable reserves
Underground: 5.4 million tons
Surface: 0.6 million tons
Pending mine plans:
1 lease
1 mine plan
680 acres
Small underground recoverable reserves
No mine plans:
38 leases
20 lease blocks
64,698 acres
179 million tons recoverable reserves
Underground: 169 million tons
Surface: 10 million tons
Development prospects: undeveloped leases
Uncertain development prospects:
23 leases
7 lease blocks
38,334 acres
104 million tons recoverable reserves
Unfavorable development prospects:
15 leases
13 lease blocks
26,360 acres
75 million tons recoverable reserves

SOURCE. Office of Technology Assessment,

plans (table 56). None of these leases are expected to be brought into commercial production by 1991. The production prospects for the one lease included in a pending mine plan are also unfavorable during this period, although the owner of Federal and fee coal now being mined near this property has expressed interest in acquiring this lease.

Over **90** percent of the recoverable reserves on undeveloped leases are underground reserves. Twenty-five of these leases (8 blocks) have uncertain development potential for 1991; the remaining undeveloped leases have unfavorable development potential for 1991. There are three main reasons for the unfavorable production prospects of these leases: 1) a depressed metallurgical coal market, 2) difficult and costly underground mining conditions, and 3) a high Federal royalty relative to royalties charged for fee coal in the State.

Chapter 7

The Powder River Basin
“A Case Study”

Contents

List of Tables

List of Figures

CHAPTER 7

The Powder River Basin: A Case Study

As the preceding chapter has shown, the Powder River basin of Wyoming and Montana contains the largest pool of undeveloped leased Federal coal reserves with favorable development potential in the United States. Furthermore, the production of Federal reserves from the Powder River basin now accounts for about half of all Federal coal production in the country. Because of the important role of this region in Federal coal production, this chapter examines the Powder River basin in more detail, The chapter includes a mine-by-mine examination of the Federal reserves scheduled to be produced over the next 10 years from currently operating or permitted mines, an analysis of the production prospects of each undeveloped lease and preference right lease application (PRLA) in this region, a discussion of the role of non-Federal mines in Powder River basin coal production, a consideration of demand for Powder River basin coal in the post-1990 period, and an examination of the different points of view on the large-scale new leasing of Federal coal scheduled for the Powder River basin in 1982.

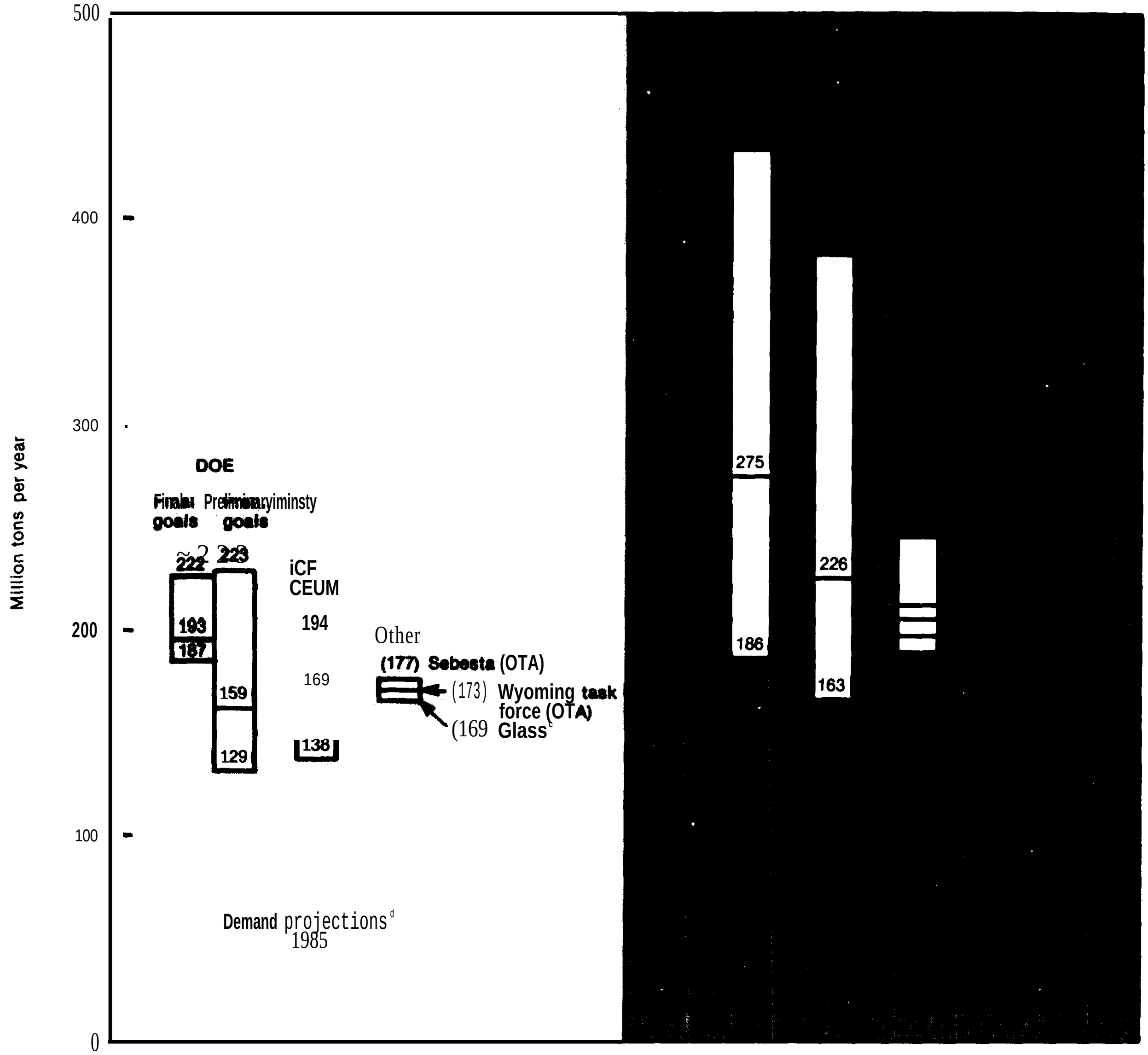
Two Demand Scenarios for the Powder River Basin

In order to evaluate the production prospects of Federal leases in the Powder River basin, it is necessary to identify the likely demand for Powder River basin coal over the next 10 years. In this analysis, OTA used a high demand scenario and a low demand scenario developed for the Powder River basin case study. This section considers a range of demand forecasts for Powder River basin coal, arrives at a "most likely range" of demand for 1985 and 1990, and examines the assumptions about high and low demand used in the analysis of Federal coal production prospects in this chapter.

Figure 34 summarizes several recent demand forecasts for Powder River basin coal for 1985 and 1990.[1] The Department of Energy (DOE) and ICF, Inc.'s CEUM (Coal Electric Utility Model) use basically the same computer model but vary a number of input assumptions (e.g., the overall growth rate of electricity demand in the United States) to arrive at three projections each for 1985 and 1990: low, midlevel (or base), and high. The Silverman forecasts (made for 1990 but not for 1985) are computer projections based on a series of different assumptions about electric demand in the market area for Northern Great Plains coal, the share of that demand to be met by coal, and the fraction of that share to be met by Northern Great Plains coal. The Sebesta and Glass projections are each based on a detailed examination of utility plans and

[1]These demand farecasts are:
1. DOE: Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995 [Washington. D. C.: DOE, Aug. 7, 1980.) See also: Analysis and Critique of the Department of Energy's August 7, 1980 Report Entitled: "Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995. prepared for the Rocky Mountain Energy Co. (Washington. D. C.: ICF Inc., October 1980).
2. DOE: The 1980 Biennia] Update of National and Regional coal Production Goals for 1985, 1990, and 1995 (Washington D. C.: DOE,]anuarv 1981.)
3. ICF CEUM: Forecasts and Sensitivity Analyses of Western Coal Production, prepared for Rocky Mountain Energy Co. (Washington, D. C.: ICF, Inc., November 1980).
4. Sebesta: Demand for Wyoming Coal 1980-1991 Based Upon Projected Utility Coal Market and Demand for Montana Coall 1980-1991 Based Upon Projected Utility Market (Washington, D. C.: OTA, October 1980).
5. Wyoming task force: Result of deliberations of the OTA Wyoming task force: Cheyenne, Wyo., October 1980).
6. Glass: Wyoming Coal Production and Summary of Coal Contracts (Laramie, Wyo.: Wyoming Geological Survey, 1980).
7. Silverman: Preliminary Results from A. Silverman. University of Montana, Missoula. Private communication to OTA. Work is funded by OSM.

Figure 34.—Powder River Basin Demand Projections[a]



[a] See footnote on p. 169 for citations.
[b] Calculated by adding Sebesta's figure for the Montana portion of the Powder River basin (66 mmt/yr) to Glass' figure for the Wyoming portion (133 mmtlyr).
[c] Calculated by adding Sebeata's figure for the Montana portion of the Powder River basin (49 mmt/yr) to Glass' figure for the Wyoming portion (120 mmt/yr).
[d] For 1965 all projections assume zero demand for synfuels and for export to foreign countries from the Powder River basin. For 1990, see the text for a discussion of synfuels and foreign export demand.

contracts in the Powder River basin market area. The Wyoming task force estimate was reached after a review of the DOE, Sebesta, and Glass projections. Figure 34 also shows the DOE final production goals. The DOE final production goals and their relation to the preliminary DOE projections and to other demand forecasts are discussed in chapter 5.

Demand Projections for 1985

For 1985, demand projections range from 129 million tons per year (the DOE low) to 223 million tons per year (the DOE high). ICF projections range from 138 million tons per year to 194 million tons per year; these figures assume that there will be zero demand for Powder River basin coal for synfuels or for export to foreign countries.

Although the demand projections for 1985 span a wide range, they cluster in a much narrower range. The range of 138 million tons per year to 177 million tons per year includes the ICF low, the DOE preliminary and ICF mid, and the Glass, Sebesta, and Wyoming task force projections. This range excludes only the ICF and DOE preliminary low and high projections and the DOE final production goals.

Two other projections, not shown on figure 34, were also examined: the National Electric Reliability Council (NERC)[2] projections for total U.S. utility* coal requirements and the long-term forecast of the National Coal Association (NCA).[3] NERC arrives at an electrical demand growth rate of 3.7 percent annually and a total domestic steam coal requirement of 684 million tons in 1985. NCA assumes an electrical demand growth rate of 3.5 percent annually and projects total domestic steam coal demand in 1985 of 727 million tons in its midlevel projection. By comparison, ICF assumes an electrical demand growth rate of 3.5 percent annually; its midlevel projection is for 717 million tons of total domestic steam coal demand in 1985.

'Electric Power Supply and Demand, *1981-1990* for the Regional *Reliability* Councils *of NERC:* National Electric Reliability y Council: July 1981. The NERC figures do not explicitly project demand for Powder River basin coal and must be interpreted using assumptions about the extent of the Powder River basin market area and the market share of Powder River basin coal within the assumed market area. Therefore, NERC projections are not shown in figure 34.

'Because 95 percent of Powder River basin coal is purchased by utilities, total utility demand is a good measure of demand for Powder River basin coal in 1985.

'National Coal Association, NCA Long Term Forecast (Washington, D. C.: NCA, March 1981].

In the NERC projections, the anticipated demand in 1985 for Western steam coal (excluding lignite) in the market area for Powder River basin coal is about 205 million tons. However, other coal competes in this market area (see fig. 20). Assuming that the Powder River basin share of this market in 1985 is the same as in 1979, i.e., 65 percent, and that 95 percent of the Powder River basin coal will continue to go to the utility market, the NERC figures lead to a demand estimate of 140 million tons in 1985 for Powder River basin coal, However, Powder River basin coal could capture a larger share of Western steam coal demand in its market area in 1985 than in 1979,

OTA High and Low Demand Scenarios: 1985

OTA selected the Sebesta projection of 177 million tons per year for its high demand scenario for 1985. The Sebesta projection exceeds both the DOE preliminary and ICF midlevel projections, the NERC projections as interpreted above, and the projections of the Wyoming State Geological Survey (Glass, 1980). The Wyoming task force estimated 1985 demand to be between the Glass and Sebesta estimates.

OTA selected the ICF low projection of 138 million tons per year for its low demand scenario for 1985, This figure is lower than presently contracted Powder River basin production for 1985 (about 160 million tons per year) and allows analysis of the implications of a "worst case" scenario on development and diligence.

Demand Projections for 1990

For 1990, the projections shown in figure 34 vary widely, and the clustering of projections, although marked, offers less reliable guidance than for 1985. Projections range from 163 million tons per year (the ICF low) to 438 million tons per year (the DOE preliminary high), but the range of 163 million tons per year to 275 million tons per year includes all but the DOE preliminary and ICF high projections and the DOE mid and high final production goals.

For 1990, the projections of Sebesta and Silverman in figure 34 include only demand for steam coal. However, the ICF, DOE, and Wyoming task force projections include demand for coal for synfuel, for export to foreign countries, and for industrial use. The ICF midlevel projection includes an estimate of about 10 million tons for synfuels from Montana and Wyoming and a total demand of 8 million tons of subbituminous low sulfur coal for foreign export; it is unclear from the ICF report, however, how much of this 8 million tons is projected to come from the Powder River basin. The DOE midlevel preliminary forecast assumes about 30 million tons of coal from Montana and Wyoming for synfuels in 1990, and the DOE final production goals assume about 45 million tons of coal from these two States for synfuels. For comparison, the ICF base (midlevel) projection estimates a total demand throughout the country of less than 50 million tons of coal for synfuels in 1990; the NCA "most likely" projection is 38 million tons. The DOE midlevel preliminary forecast estimates that about 100 million tons of coal will be used for synfuels production in the United States in 1990; the DOE final production goals assume about 200 million tons.

The Wyoming task force rated one synfuels property in the Powder River basin as having favorable production prospects for 1991—the Rochelle leaseblock with production projected at 6 million tons per year for 1991. * Other synfuels properties in the Powder River basin were judged by the task force as unlikely to be producing by 1991. This projection is in agreement with the ICF projection of 10 million tons per year from all of Wyoming and Montana, as another property, Cherokee, may come into production for synfuels in southern Wyoming.

NERC projections, which include only estimates of electric utility demand for coal, are not shown in figure 34 for reasons explained in footnote 2 on p. 171. The NERC figure of 881 million tons for total U.S. utility coal demand in 1990 is comparable to the ICF midlevel number of 862 million tons, but is lower than the DOE preliminary midlevel number of 906 million tons, NCA's most likely projection of 935 million tons, and the DOE final midlevel production goal of 994 million tons. If the Powder River basin captures the same share of the market for Western steam coal in 1990 as in 1979, (i. e., 65 percent,) NERC figures translate to a demand of approximately 180 million tons for steam coal. Using the NERC estimated demand for all coal in the Powder River basin market area as the base, not just demand for Western coal, demand for Powder River basin steam coal in 1990 (assuming a 37 percent market share) would be about 170 million tons. Adding demand for industrial coal, synfuels, and foreign export, NERC projections translate to demand for Powder River basin coal in 1990 of about Zoo million tons, assuming the Powder River basin market share of Western coal and of all coal remains the same in 1990 as in 1979.

The Powder River basin share of the steam coal market may expand over the next decade. Assuming all new Western steam coal demand is for Powder River basin coal in the Powder River basin market area, but that the old demand for Western steam coal retains its 1979 split between Powder River basin and non-Powder River basin coal, NERC projections translate to a demand estimate for Powder River basin coal in 1990 of approximately 255 million tons for all uses. * * NERC projections, interpreted as described above, give a range of demand for Powder River basin coal in 1990 of about 200 million to about 255 million tons; these calculations suggest that the DOE preliminary midlevel goals are high. * * *

*The 1991 production prospects of the Rochelle lease block have become less favorable since the Wyoming task force meeting in October 1980, because of the withdrawal of two of the partners in the Panhandle Eastern Wycoal Gas Project, to which Rochelle's coal is contracted.

* *Including demand for industrial uses (5 percent addition to utility demand), synfuels and foreign export (about 10 million tons per year).

* * *The same calculations using NERC's projections for utility Western coal demand published 1 year earlier, in July 1980, lead to a demand range of 235 million to 305 million Ions for

OTA High and Low Demand Scenarios: 1990

For 1990, OTA selected the DOE preliminary midlevel forecast of 275 million tons per year for its high demand scenario, and the ICF projection of 163 million tons per year for its low demand scenario. The Wyoming task force projection of 206 million tons per year, representing the estimate of informed regional opinion, falls slightly below the average of these two demand levels. The high scenario level of 275 million tons per year is 33 percent above the Wyoming task force estimate, and the low scenario level of 163 million tons per year is 79 percent of the Wyoming task force estimate. OTA's selected low projection is lower than present contracts for 1990 delivery of Powder River basin coal (186 million tons per year) and thus allows analysis of a "worst case" for development and diligence,

Production Under OTA's Two Demand Scenarios

The next two sections examine the production prospects of all Federal coal leases in the Powder River basin for 1986 and 1991. The first of these sections focuses on the leases included in producing mines or approved mine plans; the second on undeveloped leases. This section describes the approach used by OTA to allocate production under the high and low demand scenarios.

In its two demand scenarios, OTA allocated potential production among:

1. operating and permitted Federal mines;
2. leases with no mine plans* (undeveloped leases) but with favorable development potential; and
3. non-Federal mines.

Powder River basin coal in 1990. The difference between the demands derived from NERC 1980 and 1981 projections is caused by the fact that in 1981 NERC projected 50 million Ions less 1990 demand for Western coal than it did in 1980.

*There are two mines in preliminary permit review in the Powder River basin (South Rawhide and Antelope). Because of the early stages of development of these mine plans, these leases were analyzed with the undeveloped leases.

Under the high demand scenario, demand for Powder River basin coal in 1985 and 1990 is above present contracts for those years. Thus, for all three categories of coal production, present contracts for 1985 and 1990 are assumed to be met in full under the high demand scenario. Under the low demand scenario, demand for Powder River basin coal in 1985 is about 85 percent of present contracts for 1985, and about 90 percent of present contracts for 1990. Thus, under the high demand scenario, all Federal and non-Federal mines and all undeveloped leases with contracts are assumed to be producing at or above the current contract level for those years; under the low demand scenario, they are assumed to be producing at about 85 to 90 percent of the current contract level for those years.

For both 1985 and 1990, OTA selected the ICF low demand projections for its low demand scenarios. For each of these years, under the low demand scenario, no undeveloped leases without current contracts go into production. With the exception of three lease blocks (Antelope, North Antelope, and Rochelle), the undeveloped leases in the Powder River basin do not yet have contracts. Under the high demand scenario, many undeveloped leases would likely go into production by 1990 because demand under this scenario requires considerably more production than the sum of current contracts for future delivery of coal. The difference between demand and contracts is allocated among currently operating and permitted Federal mines, non-Federal mines, and undeveloped leases with favorable production prospects. No production is allocated to leases that, for technical or economic reasons, are unlikely to be brought into production by 1990.

A share of the demand increase is assigned by formula to each Federal mine or undeveloped lease block likely to be producing in 1985 or 1990, with only its projected capacity and its contracts (if any) entering the calculation, Allocation by formula is arbitrary. Some lessees will be more successful than others in competing for new coal contracts. Production will be higher from some mines than OTA estimates indicate, and lower from others. In the following section, OTA's estimates of production from operating and permitted Federal mines plans under the high and low demand scenarios are compared with the lessees' own estimates.

Federal Leases in Approved Mine Plans and Operating Mines in the Powder River Basin

This section assesses the production prospects for Federal coal leases in approved mine plans and operating mines in the Powder River basin. Tables 57 and 58 summarize technical and production data for each operating or permitted mine with Federal coal reserves in the Powder River basin. Together, these tables provide an overview of recent Federal mine capacity and production in the basin and expected developments in the coming decade.

Table 57 presents the following information for each mine in the Powder River basin with Federal reserves:

- lessee;
- number of Federal leases in the mine plan;
- range of recoverable reserves;
- permitted mine plan and Federal lease acreage;
- date of first coal shipments;

Table 57.—Powder River Basin Federal Mine Statistics

Mine name	Lessee[c]	Number of Federal leases	Federal[a] lease reserves	Acreage: Total permitted mine plan acreage	Acreage: Federal lease acreage	First coal shipped	Cumulative production 1976-1979	Production 1979	Remaining mine life
			(billion tons)				(million tons)	(million tons)	
(Montana)									
Rosebud	Western Energy Co.	5	HM	6,198	8,227	1920's	41.3	11.7	40 years
Big Sky	Peabody Coal Co.	1	LM	2,351	4,307	1969	9.3	2.5	38 years
Spring Creek	Spring Creek Coal Co.	1	L	3,016	2,347	1980	0.0	0.0	25 years
West Decker	Decker Coal Co.	4	HM	3,137	4,961	1972	55.7	7.1	21 years
East Decker	Decker Coal Co.	1	L	4,378	9,410	1978	5.9	5.9	27 plus years
Montana totals		12	0.8	19,080	29,252		112	27.2	
(Wyoming)									
Buckskin	Shell Oil Co.	1	LM	1,467	600	1981	0.0	0.0	16 years
Rawhide	Carter Mining Co.	1	L	7,393	5,697	1977	7.2	3.6	26 years
Eagle Butte	AMAX Coal Co.	1	L	4,304	3,520	1978	4.0	3.7	37 years
Wyodak	Wyodak Resources	3	HM	3,240	1,880	1922	6.3	2.4	43 years
Cabal lo	Carter Mining Co.	2	L	10,040	5,360	1979	1.4	1.3	44 years
Belle Ayr	AMAX Coal Co.	2	L	6,280	2,401	1973	53.8	15.0	19 years
Rojo Caballos	Mobil Oil Corp.	2	L	5,815	3,959	1983	0.0	0.0	27 years
Cordero	Sunoco Energy Dev. Co.	1	L	8,232	6,560	1976	9.8	3.8	26 years
Coal Creek	Atlantic Richfield Co.	1	L	9,545	5,806	1981	0.0	0.0	35 years
Jacobs Ranch	Kerr-McGee Coal Co.	2	L	4,959	4,352	1978	6.5	4.7	22 years
Black Thunder	Thunder Basin Coal Co.	2	L	7,560	5,864	1977	10.3	6.2	38 years
Dave Johnston	Pacific Power & Light Co	6	LM	14,305	9,662	1958	13.1	3.8	16 years
Wyoming totals		24	4.4	83,140	55,680		112	44.5	
Powder River basin totals:		36	5.3	102,220	84,932		225	71.7	

[a]Non-Federal reserves in logical mining units with these Federal lease reserves will add approximately 0.3 billion tons of recoverable reserves in both Montana and in Wyoming to the above totals (approximately 0.6 billion tons in all would be added to the above Powder River basin lease total).
[b]As reported by the lessees in their mine plans.
[c]See the OTA *Working Lease List*, app. B, for a listing of both parent Companies and subsidiaries.

Key to reserve ratings:
S = small reserves (zero to 30 million tons)
LM = low to medium reserves (30 million to 100 million tons)
HM = high to medium reserves (100 million to 180 million tons)
H = high reserves (over 180 million tons)

SOURCE: Office of Technology Assessment,

Table 58.—Powder River Basin Federal Mine Production, Capacity, and Contracts
(millions of tons per year)

Mine name	1980 mine design capacity	Production 1980	1986 mine design capacity	OTA estimated production-1986 demand scenario H	L	Contracts for 1986	Lessees' estimates of production-1986	1991 mine design capacity	OTA estimated production-1991 demand scenario H	L	Contracts for 1991	Lessees' estimates of production-1991
Montana												
Rosebud	14.2	10.4	19.6	19.5	16.3	19.4	19.4	19.8	19.8	17.5	198	19.8
Big Sky.	4.6	3.0	4.6	4.6	3.9	4,6	4.6	4.6	4.6	4.1	4.6	4 6
Spring Creek	0.2	01	10.0	7.6	5.9	7.0	7.6	10	9.2	6,2	7.0	10,1
West Decker	10,4	5.6	10,4	7.5	5.6	6.7	8.0	10.4	9 4	5 9	6 7	8.0
East Decker.	67	5.6	6.7	6.8	5.6	6.7	6.6	6.7	6.9	5.9	6.7	6 6
Montana totals	36	24.7	52	46	37	44	46	52	50	40	45	49
Wyoming												
Buckskin .,	0	0	6.2	6.2	5.2	6.2	6,2	6.2	6.2	5.5	6.2	6.2
Rawhide and Caballo . . .	12+4	6.4	24+ 12	20.4	13.5	16.0	31.0	24+ 12	30.7	14.2	16.0	360
Eagle Butte and Belle Ayr	14+21	24.5	25+ 11	33.7	27.8	33.0	33.0	25+ 1 l[a]	35.2	29.2	33.0	320
Wyodak	3	2.6	5	3 4	2.5	3.0	3.0	5	4.9	4.0	4,5	4 5
Rojo Caballos	0	0	9	4.5	2.7	2.6	9.0	15	12.5	5.0	5.6	15.0
Cordero	24	6.5	24	13,9	9.3	11.0	16.0	24	20.5	9,7	11.0	24.0
Coal Creek. .	0	0	12	6.4	4,0	4.8	9.8	12	101	4.2	4.8	12
Jacobs Ranch	16	8.2	16	13.6	11.1	13.2	15.6	16	15.3	11.7	13.2	156
Black Thunder.	14	10.5	20.5	17.4	13.9	16.5	17.0	20.5	19,4	14.6	16.5	20.5
Dave Johnston	3.8	3.8	3.8	3.7	3.1	3,7	3.7	3.6	3.6	3 3	37	3 7
Wyoming totals	112	62.5	169	123	93	110	144	175	159	101	115	170
Powder River basin totals.	148	87.2	220	169	130	154	191	226	209	141	159	219

[a]This capacity estimate based on remaining reserves.

SOURCE: Office of Technology Assessment

- recent production levels; and
- remaining mine life.

Table 58 summarizes information on capacity, production, and contracts for this decade. Mine design capacity and production are presented for 1980. Capacity figures for 1986 and 1991 are then followed by estimated production for each of these years under the high and low demand scenarios discussed in the preceding section, The amount of coal already contracted for 1986 and 1991 is listed next, along with the production estimated by each lessee. Contract information and company estimates of production are taken from lessee mine plans submitted to the Office of Surface Mining (OSM) or from communications with the lessees.

Size of Federal Mines in the Powder River Basin

Acreage: There are over 100,000 permitted mine plan acres for mines with Federal leases in the Powder River basin; 85,000 of these acres contain Federal reserves. Eighty percent of the permitted acreage is located in the Wyoming section of the basin, Not all of the Federal lease acreage associated with Federal mines is necessarily included in the permitted mine plan. In the Montana portion of the Powder River basin, for example, the five Federal leases associated with the Rosebud Mine cover 8,227 acres but only 75 percent of this acreage is permitted in the mine plan; the total acreage permitted in the mine plan at the East Decker Mine is less than 4,400 acres although the four Federal leases associated with this mine cover approximately 9,400 acres,

Lease acreage is important for gaging potential environmental impacts, but it is not always a good indicator of mine capacity or production potential. The Dave Johnston Mine, for example, has a small capacity (3.8 million tons per year) compared to other mines in the basin even though it includes the largest total Federal lease acres (9,662) and the greatest number of mine plan acres (14,305) in the basin. This mine has been in production since 1958. At present, mining is limited to two seams, which average about 45 ft in thickness and are captive to a powerplant that can use only 3.8 million tons per year.

Reserves: About 90 percent of the nearly 6 billion tons of recoverable reserves associated with approved mine plans or operating mines with Federal leases in the Powder River basin are Federal reserves. As table 57 shows, the Federal lease reserves associated with these approved mine plans and mining operations are generally large (over 180 million tons). Only three of these mines have Federal lease reserves of less than 100 million tons.

Mine Life: Mines with Federal leases in the Powder River basin have substantial production potential manifested by the mine life remaining for these properties. Estimates for remaining mine life in table 57 are taken from the lessees' mine plans. Mine life estimations are calculated by dividing the remaining recoverable reserves by the lessees' long term annual production plans. Should production fall below the lessees' estimates, then mine life would be extended. This could happen in a number of cases if demand for Powder River basin coal in 1990 turns out to be close to the estimates made by the Wyoming task force (see fig. 34) and does not subsequently increase rapidly in the 1990's. Mine life could also be extended if a lessee obtains additional reserves.

Most of the mines with Federal leases in the Powder River basin that opened in the late 1970's, or are still under construction, are expected to remain in production for at least 25 years. Only two mines (East Decker in Montana and Buckskin in Wyoming) will have a capacity of less than 10 million tons per year by 1991. The two mines that opened in the 1920's, Rosebud in Montana and Wyodal in Wyoming, are scheduled to remain in production for another 40 years. The Dave Johnston Mine, which opened in the late 1950's, has 16 years expected mine life (3.8 million tons per year capacity); the Big Sky Mine, which opened in 1969, has 38 years of mine life remaining (4.6 million tons per year capacity).

Trends in Mine Capacity and Production

Most of the 17 mines with Federal leases in the Powder River basin are currently operating below capacity. These mines produced 87 million tons in 1980, 61 million tons less than their combined design capacity of 148 million tons. The design capacity of these mines is expected to increase by 50 percent in this decade from 148 million tons per year in 1980 to 226 million tons per year in 1991. The magnitude of this increase in capacity is illustrated by a comparison of the Belle Ayr Mine in Wyoming with several of the newer mines in the basin. Belle Ayr has achieved the highest annual production of coal in the United States since 1977. However, Belle Ayr's current capacity (21 million tons per year) is scheduled to be surpassed by three new mines in the basin by 1986: Eagle Butte (25 million tons per year), Rawhide (24 million tons per year), and Cordero (24 million tons per year). Production at Belle Ayr is expected to decrease from its present high level.

Demand will dictate whether or not the design capacity of mines with Federal leases in the Powder River basin will be fully used over the next 10 years. Under OTA's low demand scenario, substantial overcapacity of these mines will continue and capacity utilization will not move much beyond 60 percent in either 1986 or 1991. * Under OTA's high demand scenario, production at these mines would reach 77 percent of capacity in 1986 and 92 percent of capacity in 1991. According to the lessees' estimates of production, capacity utilization will be 87 percent in 1986 and 97 percent in 1991. Contracts have been secured for 70 percent of capacity for both 1986 and 1991.

*I! is possible that not all of this capacity would be developed if markets for Powder River basin coal were weak. The potential for continued overcapacity in the Powder River basin is increased when the undeveloped lease blocks are considered in the next section,

Expansion of New Federal Mines in the Powder River Basin

Of the 17 mines with Federal leases in the Powder River basin, 11 are relatively new, i.e., have opened since 1976 or will open early in this decade. These new mines now account for over 90 million tons of capacity and are scheduled to reach a total capacity of over 165 million tons per year by 1986, and over 170 million tons per year by 1991.

New mines with Federal leases in the Powder River basin have generally followed the same development pattern, reaching a large capacity and high levels of production within a decade after they open. By 1986, according to the lessees' production plans, most of the 11 new Federal mines in the Powder River basin will be producing at least 75 percent of capacity. By 1991, according to the lessees' production plans, nearly all of these new mines will be producing at, or nearly at, full capacity. Each of these new mines has a contractual commitment for production through 1991. In some cases these contracts represent a substantial amount of capacity.

Several of these new Federal mines illustrate the rapid expansion of Federal mine capacity and production in the Powder River basin. For example, the Eagle Butte Mine in Campbell County, produced 3.7 million tons in 1979 after opening in 1978. By 1986, Eagle Butte is likely to be the largest coal mine with Federal leases in the United States with a capacity of 25 million tons per year and production of 23.8 million tons per year needed to fill its contract obligations. Only Federal reserves will be mined at Eagle Butte after 1985. AMAX has contracts for 90 percent of the reserves planned for production at both its Eagle Butte and Belle Ayr mines. Coal from these mines is marketed jointly.

The Black Thunder Mine in Campbell County, Wyo., is another example of rapid expansion of Federal mine capacity and production in the Powder River basin. This mine, which opened in 1977, is scheduled to achieve a capacity of 20.5 million tons per year by late 1981. Production of Federal reserves should begin at Black Thunder in 1981 and, by 1984, Federal reserves will account for all production. Black Thunder has approximately 80 percent of capacity contracted through 1991.

The Rawhide Mine in Campbell County, which also opened in 1977, showed low cumulative production (7.2 million tons per year) in the 1976-79 period. However, the lessee expects to be producing at full capacity at a rate of 24 million tons per year by 1986, although new contracts to achieve this level have yet to be signed. This capacity should be available in 1985, 8 years after the first coal was shipped from the mine. The lessee, Carter Mining Co., markets coal jointly from its Rawhide and Caballo mines and has contracts for 16 million tons per year beginning in 1984. Only Federal reserves will be produced at these mines.

Importance of Federal Reserves

Over the next 10 years, the proportion of Federal reserves that will be recovered at these mines will increase substantially. Of the 11 new Federal mines in the Powder River basin, three (Rawhide, Eagle Butte, and Caballo) were producing no Federal reserves in 1979. However, by 1986, each of these three new mines will produce only from Federal reserves.

The growing importance of Federal reserves in the Powder River basin is illustrated in table 59. In 1979, Federal reserves accounted for 42 percent of the total production of coal from mines with Federal leases in the Powder River basin. By 1986, according to lessee mine plans, 90 percent of the coal produced from these mines will be from Federal reserves. This percentage is expected to hold for 1991. *

*Note that the estimated percentage of Federal production differs little between 1986 and 1991 and among the three production estimates. However, the production of non-Federal reserves will decrease substantially in the early 1980's, from 42 million tons per year in 1979 to 20 million tons per year in 1986 (according to lessee estimates) while, at the same time, the production of Federal reserves will be increasing substantially.

Table 59.—Estimates of Federal Portion of Federal Mine Production in the Powder River Basin[a]

1979 actual production (million tons per year)		1986 estimated production (million tons per year)			1991 estimated production (million tons per year)		
Total: 72	OTA high demand scenario[c]	Total: 169	Federal: 150	% Federal: 89%	Total: 209	Federal: 189	% Federal: 90%
Federal: 30	OTA low demand scenario[c]	Total: 130	Federal: 116	% Federal: 89%	Total: 141	Federal: 125	°/0 Federal: 89°/0
°/0 Federal: 42°/0	Lessee estimates[b,c]	Total: 191	Federal: 171	% Federal: 90%	Total: 219	Federal: 201	°/0 Federal: %? °/o

[a]Federal mines in currently approved mine plans only.
[b]Lessee estimates are taken from the mine plans.
[c]For 1986 and 1991, in the Montana portion of the powder River basin, the Federal portion of Federal mine production is estimated to be approximately 65 percent in all three estimates; in the Wyoming portion, the Federal portion is estimated to be over 97 percent.

SOURCE: Office of Technology Assessment

Nonfederal Mines in the Powder River Basin

Five mines with no Federal reserves in the Powder River basin (two in Montana and three in Wyoming) were responsible for 11.7 million tons of coal production in 1980. These five mines had a combined capacity of nearly 20 million tons per year compared to 148 million tons per year of total Federal mine capacity in the basin. Table 60 compares the capacity of currently operating and permitted Federal mines with non-Federal mines that have favorable production prospects. Scheduled capacity for these mines is presented for 1986 and 1991. The total non-Federal share of capacity in the basin is unlikely to go beyond 12 percent in 1986 and 16 percent in 1991.

Table 61 presents information on the capacity and contracts for non-Federal mines in the Powder River basin that are likely to be in production by either 1986 or 1991. While the combined capacity of 12 non-Federal mines in the Powder River basin could increase substantially during this decade—to 29 million tons per year in 1986 and 44 million tons per year in 1991—only three of these mines

Table 60.—Capacity in the Powder River Basin: Federal and Non-Federal Mines

	1980 (million tons per year)	1986[a] (million tons per year)	1991[a] (million tons per year)
Montana			
Federal mines	36	52	52
Non-Federal mines	11	13	30
Total	47	65	81
Wyoming			
Federal mines	112	169	175
Non-Federal mines , . . .	9	16	14
Total	121	184	189
Powder River basin totals			
Federal mines	148	220	226
Non-Federal mines , . . .	20	29	44
Total , ... , ...	188	249	270

[a]Does not include potential capacity from undeveloped Federal leases. See table 63

SOURCE: Office of Technology Assessment.

Table 61.— Non-Federal Mine Development in the Powder River Basin, 1986-91

	1986		1991	
Likely by 1991	Capacity	Contracts	Capacity	Contracts
Montana:				
Absaloka[a]	10.5	5.1	10.5 (15)[c]	5.1
Brophy No. 2	0.2	0	0.2	0
Montco	2.0	0	9.0 (12)[c]	0
Young's Creek	—	—	8.0	0
Coal Creek[a]	0.2	0	0.2	0
Bull Mountain	0.5	0	2.0	0
Totals	13.4	5.1	29.9	5.1
Wyoming:				
Bighorn[a]	3.0	3.0	3.0	3.0
Dutchman	1.0	0	1.0	0
Welch No. 1	. 1.0	0	1.0	0
Wymo[b]	4.0	2.0	4	2.0
Fort Union[a]	1.5	0	0	0
Clovis Point[a]	5.0	0	5.0	0
Totals	15.5	5.0	14.0	5.0
Grand totals	28.9	10.1	43.9	10.1

[a]Producing in 1980. Total capacity of mines producing in 1980 is 20 million tons per year.
[b]Contracts for captive production for utilities. The capacity shown here could probably not be sustained much beyond 1991 without new leasing of Federal coal.
[c]Potential capacity in the 1990's.

SOURCE: Office of Technology Assessment.

now have contracts for a total of 10.1 million tons per year for 1991.

Estimated Cumulative Production Under OTA's High and Low Demand Scenarios for the Powder River Basin 1976=91

Table 62 presents information on the cumulative production of mines with Federal leases under OTA's high and low demand scenarios. Cumulative production from these mines in the basin from 1980-91 under the high demand scenario (1,916 million tons) is 30 percent more than that projected under the low demand scenario (1,480 million tons).

In the 1976-79 period, the cumulative production of mines with Federal leases in the Wyoming and Montana sections of the Powder River basin were almost identical. However, mines with Federal leases in the Wyoming section of the basin, with their larger reserves, will dominate coal production in this decade. Most of this new production will come from the nine new mines discussed above. The Eagle Butte Mine, for example, shipped its first coal in 1978 and produced only 4 million tons between 1976-79; however, under OTA's high demand scenario, this mine would produce 95 million tons between 1980-86, and 110 million tons between 1987-91. The Cordero Mine, which opened in 1976, also has the potential for high cumulative growth from 1980 to 1991; from 9.8 million tons in the 1976-79 period to 61,4 million tons in 1980-86 and 72.4 million tons in 1987-91. Similar increases could occur at the other new mines in the basin. Some increased production will also come from the expansion of older mines.

Table 62.—OTA Estimated Cumulative Production[a] Under High and Low Demand Scenarios for the Powder River Basin: 1976-91 (millions of tons)

	Cumulative production 1976-79	Estimated cumulative production 1980-86	Estimated cumulative production 1987-91	Estimated cumulative production 1980-91
Montana portion of the Powder River basin.	112	H -272 L -232	H -243 L -194	H - 514 L - 425
Wyoming portion of the Powder River basin.	112	H -677 L -561	H -726 L -493	H -1402 L -1054
Total Powder River basin	225	H -948 L -793	H -968 L -687	H -1916 L -1480

[a]For operating and permitted mines with Federal leases. See table 57, powder *River Basin Federal Mine* Statistics. Potential production from undeveloped leases is not Included in these tables

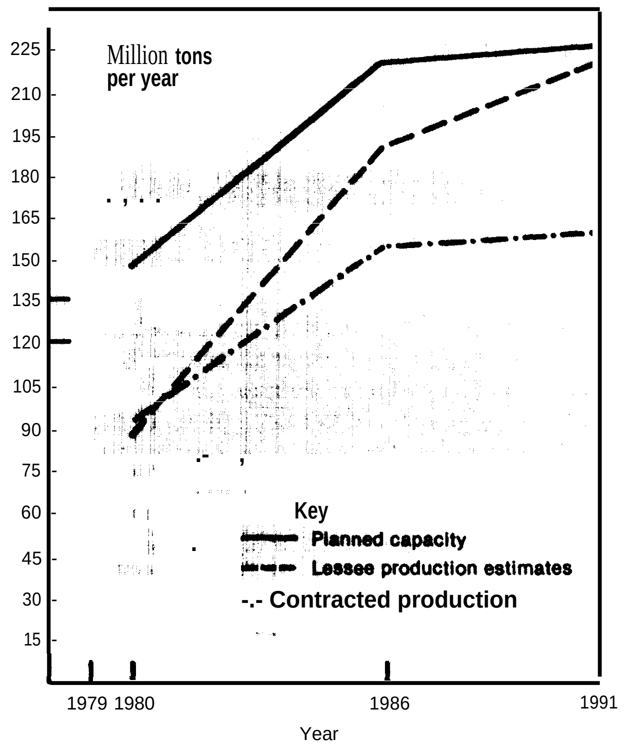
SOURCE: Office of Technology Assessment

Lessee Production Plans and OTA High= Low Demand Scenario Projections: A Summary Comparison

Figures 35 and 36 present a graphic comparison of the production estimates of the lessees with those under OTA's high and low demand scenarios presented in table 58. The lessees' estimated production for 1986 is 23 percent (36 million tons) more than production currently under contract for that year;

Figure 35.— Lessee Production Estimates

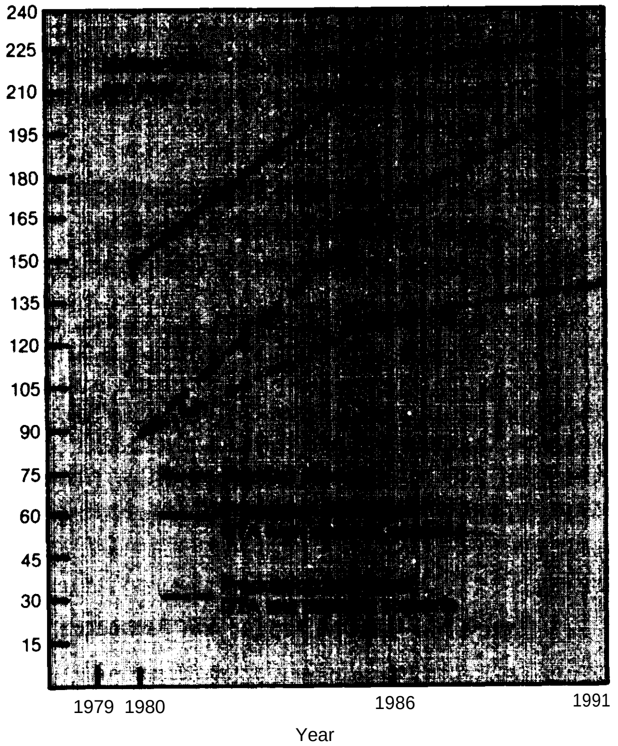
For operating and permitted mines with Federal leases (see table 58)



SOURCE: Office of Technology Assessment.

Figure 36.—Production Estimates: OTA High and Low Demand Scenarios

For operating and permitted mines with Federal leases (see table 58)



SOURCE: Office of Technology Assessment.

for 1991 their estimated production is 38 percent (60 million tons) more than coal currently under contract for 1991.

OTA's estimates of production under the high demand scenario in 1991 are only 10 million tons less than the production estimates of the lessees, however, OTA's production estimates under the low demand scenario are substantially lower than those of the lessees. For 1991, the difference between the two projections is 78 million tons. OTA's estimates under the low demand scenario closely parallel production already under contract.

Development Potential and Production Prospects of Undeveloped Leases in the Powder River Basin

The preceding section examined the production prospects of operating and permitted mines with Federal leases in the Powder River basin for 1986 and 1991. The discussion focused on the design capacity, total production, and production of Federal reserves from these mines over the next 10 years. This section examines the production prospects of the 21 undeveloped lease blocks (37 leases) in the Powder River basin under OTA's high and low demand scenarios. The production estimates for each of these leases are based on OTA's review of their development potential, the plans of the lessees, and other considerations likely to affect production,

The potential capacity that these leases could add to the Powder River basin is significant, totaling 81 million tons per year by the end of this decade. Under OTA's high demand scenario these leases could produce 11 million tons in 1986; under the low demand scenario, 5.6 million tons. In 1991, under the high demand scenario, these leases could produce 65 million tons per year; their production would only be 17 million tons in 1991 under the low demand scenario. However, as table 63 shows, 11 undeveloped lease blocks (20 leases) of the 21 undeveloped lease blocks (36 leases) in the Powder River basin have unfavorable production prospects over the next

Table 63.—Production Prospects for Undeveloped Leases: Powder River Coal Basin

Development potential	Lessee[4]	Number of Leases	Location by county[1]	Acres	Capacity[2] (million tons)	Reserves (billion tons)	Production prospects[3] 1986	Production prospects[3] 1991
Leases with favorable development potential								
Antelope	Resource Development Co.	3	Converse	4,817	8.0 (12.0)	L	Favorable(a)	Favorable
N. Antelope	N. Antelope Coal	1	Campbell	320	5.0	S	Favorable(a)	Favorable
South Rawhide	Carter Mining	1	Campbell	4,782	12.0	L	Favorable(b)	Favorable
Rochelle	Peabody Coal	2	Campbell	8,821	6.0 (11.0)	L	Unfavorable	Favorable(e)
Dry Fork	Cities Service	3	Campbell	3,580	8.0 (15.0)	L	Uncertain	Uncertain
E. Gilette Fed.(h)	Kerr-McGee Co.	3	Campbell	4,343	15.0	L	Uncertain	Uncertain
N. Rochelle	Shell Oil Co.	1	Campbell	2,000	8.0	L	Uncertain	Uncertain
CX Ranch	Consolidation Coal	1	Big Horn, Mt	674	8.0	S	Uncertain	Uncertain
CX Ranch	Peter Kiewit Sons, Inc.	1	Big Horn, Mt	524	4.0	S	Unfavorable	Uncertain
Wildcat	Gulf Oil Co.	1	Campbell	1,571	7.0 (10.0)	L	Unfavorable	Uncertain(e,g)
Lake DeSmet(e)	Texaco	5	Johnson	9,417	— (20.0)	L	Unfavorable	Unfavorable(e,g)
Phillips Creek (l)(c)	PPL	4	Converse	4,039	—	S	Unfavorable	Unfavorable
Totals		26		44,888	81 (120)	3.3		
Leases with uncertain development potential								
Bass Trust(f)	R.D. Bass Trust Estate	1	Sheridan	20,701	–	L	Unfavorable	Unfavorable
Belco(f,h)	Belco Petroleum	1	Johnson	4,551	—	L	Unfavorable	Unfavorable
Gulf (1) & (2)(f)	Gulf Oil Corp.	3	Sheridan	4,366	—	HM	Unfavorable	Unfavorable
East Wyodak(d)	Peabody Coal	1	Campbell	2,560	— (7.0)	LM	Unfavorable	Unfavorable(e,g)
Pearl	Shell Oil Corp.	1	Big Horn, Mt	541	– (2.0)	LM	Unfavorable	Unfavorable
Totals		7		32,719	– (9.0)	0.7		
Leases with unfavorable development potential								
Armstrong(h)	Big Horn Coal	1	Sheridan	80	–	S	Unfavorable	Unfavorable
Blue Diamond	Wyodak Resources	1	Campbell	40	—	s	Unfavorable	Unfavorable
Gulf (3)(h)	Gulf Oil Corp.	1	Campbell	756	–	S	Unfavorable	Unfavorable
Phillips Creek (2)	PPL	1	Converse	40	–	s	Unfavorable	Unfavorable
Totals		4		916	–	<0.01		

[1]Counties are in Wyoming unless otherwise noted
[2]Numbers without parentheses show capacities for 1991, numbers in parentheses indicate capacities after 1991
[3]Where footnote appears under "development potential" it is relevant to the development of the lease. Footnotes under "production prospects" are relevant to production prospects only.
[4]See the Working Lease List, app. B, for a listing of both parent companies and subsidiaries

Key to production prospects
(a) coal already under contract
(b) coal may be combined with contracted production of another mine owned by the same company
(c) plans to incorporate into existing mine plan
(d) may be Incorporated with PRLA to form LMU
(e) production contingent on synfuel development
(f) production dependent on in situ gasification
(g) production contingent on onsite steam electric plant
(h) may be traded under provisions of Public Law 95-554

Key to reserve ranking
S = small reserves (zero to 30 million tons)
LM = low to mediem reserves (30 million to 100 million tons)
HM = high to medium reserves (100 million to 180 million tons)
L = large *reserves (over* 180 million tons)

SOURCE Off Ice of Technology Assessment

10 years even under favorable market conditions.

Undeveloped Leases With Favorable Development Potential

Four undeveloped lease blocks (7 leases)—Antelope, North Antelope, South Rawhide and Rochelle—in the Powder River basin with favorable development potential have favorable production prospects for 1991. These lease blocks cover 18,740 acres; three contain relatively large reserves.

Only one of these lease blocks, Rochelle, is not likely to be producing under OTA's low demand scenario in 1986. Production at the Rochelle lease is contingent on the pace of development at the Panhandle Eastern Gasification plant in Douglas, to which 500 million tons of Rochelle's reserves have been committed. Panhandle's plans called for production in 1986, using coal at a rate of about 6 million tons per year with an additional 1 million to 2 million tons per year possibly going to an associated steam/electric plant. DOE has funded a feasibility study on the Panhandle

Eastern project but production prospects for the Rochelle lease are unfavorable for 1986 because of the time required for the development of a synthetic fuels project. However, by 1991 the Rochelle lease is assumed to produce 6 million tons of coal under both the high and low demand scenarios. *

The South Rawhide lease, although without contracts, would begin production in 1985 and expand to 9 million tons per year by 1991 under the high demand scenario. If no contracts are obtained for this property, the lessee (Carter Mining Co.) may mine coal at South Rawhide to blend with the coal produced at the company's Rawhide and Caballo mines for which contracts have already been secured. If this occurs, production at the Rawhide and Caballo mines would be reduced proportionately.

Coal from the North Antelope lease will be shipped to Middle South Utilities in Arkansas, a group of several utilities scheduled to begin operation in 1984. Using company projections for this lease, OTA has estimated that approximately 4.5 million tons per year will be produced under the low demand scenario and 5 million tons per year under the high demand scenario in 1991 unless construction of the plants is delayed. Mining operations at North Antelope will include reserves from the Rochelle lease.

All planned production from the Antelope lease is also contracted through 1991; thus, production prospects for both 1986 and 1991 for this lease are favorable. The lessee plans to produce 5.6 million tons per year by 1990 and increase production to 12 million tons per year by 1993.

Four lease blocks (eight leases) with favorable development potential, covering 10,696 acres, have uncertain production prospects for both 1986 and 1991. Thus, under OTA's high demand scenario these lease blocks could be producing by 1991; however, their prospects for production are unfavorable through 1991 under the low demand scenario. Three of these lease blocks—Dry Fork, East Gillette Federal, and North Rochelle—have substantial reserves and favorable property characteristics. The CX Ranch lease, held by Consolidation Coal Co., has small Federal reserves with otherwise favorable property characteristics and is associated with significant amounts of non-Federal coal.

The Dry Fork lease block, held by Cities Service Co., could produce 0.4 million tons per year by 1986 and 5.9 million tons per year by 1991 under the high demand scenario. Six hundred forty acres of State coal could possibly be included in mining operations. There are no contracts for coal from the lease at this time.

According to the Western Coal Planning Assistance Project, coal produced on the East Gillette Federal lease block (which could produce 11 million tons in 1991 under the OTA high demand scenario) will be delivered to four utilities in Arkansas, Louisiana, and Oklahoma. Parts of two of the three leases at East Gillette Federal are included in exchange negotiations authorized under Public Law 95-554, but the exchanges would not affect the viability of the mining operation. (See ch. 9 for a discussion of exchanges.)

North Rochelle's production could reach 5.9 million tons per year by 1991 under the high demand scenario. The lessee, Shell Oil Co., plans to apply for a mining permit by 1984 and is currently conducting mine feasibility and environmental studies. It appears likely that sales of the coal on the lease will be directed to steam/electric use, at least in the near term, though none of the coal has yet been sold. Another option for Shell is to use the coal to meet contract obligations at Shell's Buckskin Mine, where the status of some recoverable reserves is uncertain because of alluvial valley floor considerations. Development for synfuels is also a possibility for the 1990's.

Consolidation Coal's CX Ranch could begin production before 1986; capacity could be 8

*The 1991 production prospects of the Rochelle lease block have become less favorable recently because of the withdrawal of two of the partners in the Panhandle Eastern WyCoal Gas Project.

million tons per year by 1991. Federal coal has been integrated with State and fee coal already held by the lessee. Although markets for the coal have yet to be identified, the lessee is exploring both steam/electric and synthetic fuels markets. Environmental studies are underway and the lessee plans to submit a mine permit application in 1981. Under the high demand scenario, in 1991 Consolidation's CX Ranch lease could produce close to 6 million tons per year. *

Both the CX Ranch lease, held by Peter Kiewit Sons, Inc., and Gulf Oil's Wildcat lease have unfavorable production prospects for 1986. Either lease could be producing by 1991 under the high demand scenario but neither is likely to be producing by 1986 even under the high demand scenario.

Production from Gulf Oil's Wildcat lease could reach 5 million tons per year by 1991 with much of this tonnage expected to be used for onsite power generation. The lessee has developed a preliminary mine plan that may be submitted within the next few years, However, development of this lease block may be more difficult and costly than the development of most other leases in Campbell County because the geology of the coal seams is very complex. The CX Ranch lease could have a capacity of 4 million tons per year and produce close to 3 million tons per year by 1991; however, none of the coal on the lease has yet been sold.

Two lease blocks (9 leases) with favorable development potential—one contingent on synfuels, (Lake DeSmet) the other contingent on integration into an existing mine (Phillips Creek (l))—have unfavorable production prospects for both 1986 and 1991. Thus, these leases are not likely to go into production by 1991 even under the high demand scenario. Lake DeSmet has large reserves, Phillips Creek small reserves. The Phillips Creek block, recently acquired by the Pacific Power & Light Co. is expected to be incorporated into the Dave Johnston Mine. Even if this occurs, mining of the lease would probably not take place until after 1991,

Although four of the five Lake DeSmet leases are not contiguous, the lessee owns all of the intervening non-Federal coal. Production from this lease depends on the development of synfuels. The lessee submitted a joint application to DOE for a feasibility study with Transwestern Coal Gasification Co. However, this study was not funded. No commitments or contracts for development of the coal have yet been obtained.

Undeveloped Leases With Uncertain Development Potential

Five lease blocks (7 leases) in the Powder River basin—Bass Trust, Belco, Gulf (l&2), East Wyodak, and Pearl—have uncertain development potential. These leases contain **32,719** acres and have sizable reserves. Each lease has unfavorable production prospects for both 1986 and 1991. It is unlikely, therefore, that these leases would go into production by 1991 even under OTA's high demand scenario.

The production prospects of the Bass Trust, Belco, and Gulf (l&2) lease blocks are contingent on the development of in situ gasification, which is not likely to proceed before the 1990s. The Bass Trust lease, the largest Federal coal lease ever issued, has poor coal quality, thin seams and a high stripping ratio. Similarly, the Gulf (l&2) lease block does not appear to be commercially minable by conventional techniques because of a high stripping ratio. To date, the lessee has not filed applications to DOE for pilot plant development, and no other plans for development were identified for the near term. The Belco lease is authorized for trade under the provisions of Public Law 95-554.

The reserves on the East Wyodak lease might support an onsite coal conversion plant if integrated with 640 acres of contiguous State coal held by the lessee, but stripping ratios are probably too high to develop a mine for export markets. In addition, the lessee also holds a block of PRLAs on land adjacent

*See ch. 10 for a discussion of the alluvial valley floor situation at the CX Ranch leases.

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to East Wyodak. The lessee has expressed serious intention to bring these reserves into production when more favorable market conditions prevail.

A final environmental impact statement (EIS) was submitted on the Pearl lease after the lessee (Shell Oil Co.) had conducted a comprehensive planning assessment. In spite of such an investment of time and resources, development of this property has been postponed. The amount of lease reserves is marginal and the stripping ratios high. Furthermore, the lease reserves are located in two blocks separated by unleased Federal coal.

Undeveloped Leases With Unfavorable Development Potential

Four leases—Armstrong, Blue Diamond, Gulf (3) and Phillips Creek (2)—have unfavorable development potential and thus unfavorable production prospects, even under strong market conditions. These leases have small reserves, poor property characteristics, and little chance of being integrated with another coal property to form a logical mining unit. The owners of these leases have given no indication that they will be developed. The Armstrong and Gulf (3) leases are authorized for trade under the provisions of Public Law 95-554.

Development Potential and Production Prospects of PRLAs in the Powder River Basin

There are 58 PRLAs in the Powder River basin covering a total of 95,228 acres and including recoverable reserves ranging from less than 30 million tons to over 180 million tons. Table 64 presents information on the development potential and production prospects of these 58 PRLAs that are grouped into 19 blocks using the criteria of contiguity and common ownership applied to undeveloped leases. Acreage and reserve ratings are also presented for each block. 1994 is the key year for which to assess the production prospects of PRLAs because the stated policy of the Department of the Interior (DOI) is to process all outstanding PRLAs by December 1, 1984 (43 CFR 3430.3-l(a)). If this schedule is met, diligence requirements for all PRLAs will have to be met by 1994 at the latest. *

None of the PRLA blocks with large recoverable reserves appears to have favorable development potential. The three PRLA blocks with favorable development potential cannot contribute substantially to the capacity of mines with Federal leases in the Powder River basin because of their small reserves. The PRLA blocks that might increase Federal mine capacity substantially in the basin—Peabody (P4), and Consol (1) and (2)—have uncertain development potential and production prospects.

*These leases will he subject to post -FCLAA diligence requirements.

PRLAs With Favorable Development Potential

Only three PRLA blocks (four PRLAs) of the 19 PRLA blocks (58 PRLAs) in the Wyoming portion of the Powder River basin have favorable development potential. None of these blocks would add substantially to the capacity of Federal mines in the Powder River basin. Because of their small size and small recoverable reserves (each with less than 30 million tons), these three PRLA blocks would not have favorable development potential if their incorporation into producing mines or approved mine plans did not seem likely by 1994.

The Peabody (P2) PRLA, may be incorporated into Carter Mining Co.'s Caballo Mine because it is located within the boundaries of the mine area. The Weld-Jenkins (5) PRLA, with only 80 acres, could be integrated into

Table 64.— Production Prospects for PRLAs: Powder River Coal Basin

Development prospects	Owner/parent company	Number of PRLAs	County	Acreage	Reserves (millions of tons)	Production prospects (1994)
PRLAs *with* favorable *development potential:*						
Peabody (P2)	Peabody Coal Co.	1	Campbell	520	S	Favorable (a)
Weld-Jenk~ns (5)	Weld-Jenkins	1	Campbell	80	S	Favorable (a)
North Antelope (1)	North Antelope Coal	2	Campbell	240	S	Favorable (a)
Totals		4		840	15	
PRLAs *with uncertain* development potential						
Peabody (P4)	Peabody Coal Co.	1	Converse	835	LM (4.0)[4]	Uncertain (b,c)
Consol (1)	Consolidation Coal Co.	3	Campbell	5,610	L (7.0)	Uncertain (b,c)
Consol (2)	Consolidation Coal Co.	2	Campbell	4,534	L (8.5)	Uncertain (b,c)
North Antelope (2)	North Antelope Coal	2	Campbell & Converse	1,240	s	Uncertain (d)
Arco (1)	ARCO	1	Campbell	357	s	Uncertain (d)
Arco (2)	ARCO	2	Campbell	240	s	Uncertain (d)
Peabody (P3)	Peabody Coal Co.	4	Campbell	2,200	LM	Uncertain (d)
Western Fuels (1) (Stevens North)	Western Fuels Assoc.	3	Converse	8,864	HM[1]	Uncertain (d)
Dixie (2)	Dixie Natural Resources	1	Converse	2,276	LM	Uncertain (c,e)
Thunderbird	El Paso Coal Co.	12	Campbell & Johnson	23,928	S[2], L[3]	Unfavorable (f)
Weld-Jenkins (l-4)	Weld-Jenkins	13	Campbell & Johnson	28,496	NSR	Unfavorable (f)
Totals		44		78,580	1,400	
PRLAs with unfavorable development potential						
Consol (3)	Consolidation Coal Co.	2	Campbell	3,640	LM	Unfavorable
Dixie (1)	Dixie Natural Resources	1	Converse	800	NSR	Unfavorable
Peabody (Pi)	Peabody Coal Co.	4	Campbell	3,388	S	Unfavorable
Peabody (P5) (Dull Center)	Peabody Coal Co.	2	Converse	3,628	S	Unfavorable
Western Fuels (2)	Western Fuels Assoc.	1	Converse	4,352	NSR	Unfavorable (f)
Totals		10		15,808	127	

Key to production prospects.
a = favorable if Integrated into existing LMU (in which case production of total LMU will count toward diligence requirements)
b = production contingent on onsite development (synfuels and/or steam)
c = possible procedural irregularities and/or overlapping mining claims.
d = favorable if issueed (possible procedural irregularities and/or overlapping mining claims) *and* if integrated into existing LMU.
e = possibility exists for local Industrial use of the coal
f = possibilities exist for in situ gasification.

Key to reserve ratings:
S = small reserves (zero to 30 million tons)
LM = low to medium reserves (30 million to 100 million tons)
HM = high to medium reserves (100 million to 180 million tons)
L = large reserves (over 180 million tons)
NSR = no surface reserves

[1]Reserves with stripping ratio less than 3.5 are probably small.
[2]Small surface reserves.
[3]Large underground reserves.
[4]Numbers in parentheses indicates potential mine capacity, if lease is issued.

SOURCE Office of Technology Assessment

SunEDCo's Cordero Mine. The North Antelope (1) PRLA will likely be developed with Peabody's North Antelope lease. Peabody has contractual commitments on the North Antelope lease with System Fuels for 180 million tons of coal beginning in 1985.

PRLAs With Uncertain Development Potential

Eleven PRLA bocks (44 PRLAs) covering 78,580 acres have uncertain development potential. Because of their limited reserves, the development of the North Antelope (z), Arco (1), Arco (2), and Peabody (P3) PRLA blocks is contingent on their being integrated with mines already in production. Development of the Western Fuels (1) PRLA is contingent on integration into the Dave Johnston Mine, This PRLA block has thin seams, a high stripping ratio, and the coal is of low heat content. Procedural irregularities may impede the processing of these PRLAs and their issuance as leases. The Dixie (2) PRLA would have had unfavorable development potential because of small reserves, thin seams, and low heat content of the coal but there is evidence of plans to develop the lease for local industrial use.

The production of coal from the Peabody (P4), Consol (l), and Consol (2) PRLAs is contingent on onsite development. The reserves associated with the Peabody (P4) block could support an onsite steam electric plant but are insufficient to support a synfuels project. Both the Consol (1) and Consol (2) blocks could support either an onsite steam/electric plant or an onsite synfuels plant. The issuance of leases on all three blocks maybe impeded by overlapping mining claims and/or possible procedural irregularities. These PRLA blocks might produce coal if the electrical growth rate and/or demand for synthetic fuels is higher than suggested by several estimates. Consequently, even if these PRLAs are issued as leases, their production prospects would be uncertain for 1994.

The Thunderbird and Weld-Jenkins (1-4) PRLA blocks also have uncertain development potential because their production prospects are contingent on in situ gasification, a technology that is not likely to be commercially viable by 1984. *

PRLAs With Unfavorable Development Potential

Five PRLA blocks (10 PRLAs) have unfavorable development potential. Four of these PRLA blocks have small reserves. The fifth block, Consol (3) PRLA has unfavorable development potential because it is separated into four noncontiguous blocks by unleased Federal coal.

* Preference right lease applicants must demonstrate the existence of commercial quantities of coal before a lease can be issued. Technology for in situ gasification would have to advance to the point of reasonably expected commercial viability by 1984 (the deadline for processing PRLAs) for coal reserves that are suitable only for in situ gasification to meet the commercial quantities test. This is unlikely, given the current experimental nature of this technology in the United States.

Comparison of Demand and Supply Projections for the Powder River Basin

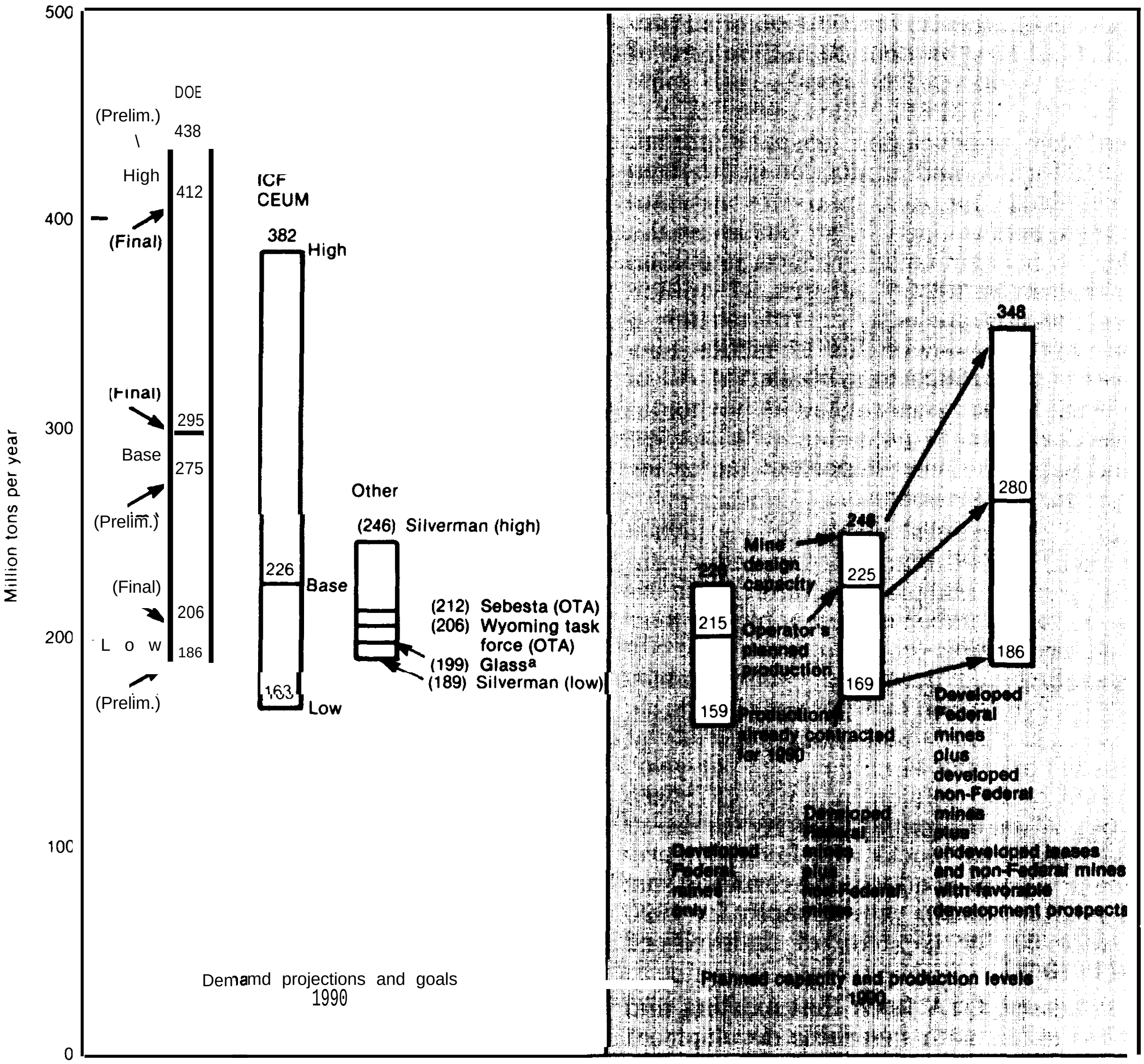
As shown in figure 37 and discussed earlier in this section, most demand projections for Powder River basin coal for 1990 range between 163 million tons per year and 275 million tons per year. The Wyoming task force projected a demand for 206 million tons per year by 1990 for coal produced in the Powder River basin. Production projections for Powder River basin coal can also span a wide range, from existing contracts with developed mines to full utilization of the mine design capacity of existing and planned mines. Figure 37 compares planned production and capacity for 1990 with demand estimates for 1990.

It should be recalled that the estimates of potential production developed in this chapter are not forecasts of the coal that would be produced at a given price or a given demand. They are estimates of the total amount of coal that could be produced from operating Federal mines and from those Federal leases that have characteristics comparable to operating mines in the same region. Coal from these leases would thus be likely to have mining costs competitive with costs at currently operating mines in the same area. If the demand for Federal coal does not increase to the levels of potential production, then not all the Federal leases that could technically and economically be developed will go into production.

The existing contracts for delivery of Powder River basin coal in 1990 from operating Federal and non-Federal mines total 169 million tons (see tables 58 and 61). An additional 17 million tons has also been contracted for 1990 from three undeveloped lease blocks (Antelope, North Antelope, and Rochelle), of which 6 million tons is for synfuels (Rochelle). Thus, there is a total of 186 million tons per year of Powder River basin coal already contracted for 1990.

The planned production of the lessees for 1990 is larger than presently contracted pro-

Figure 37.—Comparisons of Powder River Basin Demand Projections With Planned Capacity and Production Levels for 1990



[a]Calculated by adding Sebesta's figure for the Montana portion of the Powder River Basin (88 mmt) to Glass' figure for the Wyoming portion (133 mmt)

References

ICF: CEUM: Coal Electric Utility Model Forecasts and Sensivity Analyses of Western Coal Production, prepared for Rocky Mountain Energy Co (Washington, D.C : ICF Inc., November 1980)

Sebesta: *Demand for Wyoming Coal 1980-1991 Based Upon Projected Utility Coal Market and Demand for Montana Coal 1980.1991 Based Upon Projected* Utility *Market* (Washington, DC.: OTA, October 1980).

Wyoming task force: Result of deliberations of the OTA Wyoming task force, Cheyenne, Wyo., October 1980.

Silverman: Preliminary results from A. Silverman, University of Montana, Missoula, Private communication to OTA,

Glass: *Wyoming Coal Product/on and Summary of* Coal *Contracts* (Laramie, Wyo.: Wyoming Geological Survey, 1980)

DOE: *Preliminary National and Regional Coal Product/on* Goals *for 1985, 1990, and 1995* (Washington, O. C.: DOE, Aug. 7, 1980). See also: *Analysis and Critique of the Department of Energy's August 7, 1980 Report Entitled: "Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995,* prepared for the Rocky Mountain Energy Co. (Washington, D. C,: ICF Inc., October 1980).

DOE: The 1980 Biennial Update of National and Regional Coal Production Goals for 1985, 1990 and 1995 (Washington, D. C.: DOE, January 1981).

duction for 1990. For operating and permitted Federal mines, the sum of the lessees' planned production for 1990 is about 215 million tons. (See table 58 for 1991 planned production.*) At least another 10 million tons of production is planned by non-Federal mine operators (see table 61). When potential production from undeveloped leases is added, the figure for planned production in the Powder River basin for 1990 increases substantially. Ten undeveloped lease blocks in the Powder River basin could produce 55 million tons per year by 1990.** Of this, 17 million tons per year is presently contracted for; 6 million tons per year of this 17 million tons per year is committed to synfuels. *** All of these lease blocks were ranked as having favorable development potential, with market demand being the most important factor for their production prospects.

Most of the lessees' plans call for higher production in 1990 than what is under contract at present, and planned mine design capacity is, in a number of cases, higher than planned production. Planned mine capacity for operating and permitted Federal mines for 1990 is 226 million tons per year (see table 58). Planned mine capacity for non-Federal mines adds another 44 million tons per year, for a sum of 271 million tons per year (see table 61). When estimated capacity for the 10 undeveloped lease blocks with favorable production prospects is added, the resulting sum is 348 million tons per year capacity for 1990 (see table 63 for capacity of undeveloped leases in 1991).

In summary, OTA finds that existing and proposed mines with favorable development potential in the Powder River basin could sustain production of 348 million tons per year in 1990, provided the demand existed; only 6 million tons per year of this production is committed to synfuels development. This figure is substantially larger than most demand projections: over 25-percent higher than the DOE midlevel projection, over 50-percent higher than the ICF midlevel projection; nearly 70-percent higher than the Wyoming task force projection; and 75-percent higher than the projection of the Wyoming Geological Survey.

There are several reasons to suppose that the DOE midlevel projection is outside of the "most likely" range. (See discussion surrounding fig. 34.) A more reasonable "likely high" figure is the ICF base case of 226 million tons per year. Similarly, the ICF low projection of 163 million tons per year, which is less than present contracts for Powder River basin coal, is probably outside of the "most likely" range. Assuming that the "most likely" demand range is from 199 million tons per year (Glass; Wyoming Geological Survey) to 226 million tons per year (ICF base case), then potential mine capacity in the Powder River basin in 1990 may be from 122 million tons per year (over 50 percent) to 149 million tons per year (75 percent) above demand.

Potential Coal Mine Capacity in the Powder River Basin in the 1990's

The earlier sections of this chapter have discussed capacity, production and demand in the Powder River basin up to 1991. This section briefly examines the additional capacity that might be developed in the 1990's. Only capacity that can be sustained without additional leasing of Federal coal is included.

Table 65 lists all Federal and non-Federal coal properties that might produce in the 1990's and the capacity levels that their presently held reserves could support. For those coal properties likely to be in production by 1991, a total of about 26 million tons per year capacity over 1991 capacity could be added in the 1990's as follows:

- zero from Federal mines in currently approved mine plans (compare with table 59);
- about 7 million tons per year from non-Federal mines (compare with table 61);

*Note that these tables refer to 1991 production; the numbers in the text above refer to 1990 production, which is slightly less.

** Antelope, North Antelope, South Rawhide, Rochelle, Dry Fork, E. Gillette Federal, N. Rochelle, CX Ranch (Consol), CX Ranch (PKS), Wildcat. The 1990 production is 10 million tons less than potential production in 1991.

***Peabody Coal Co. 's Rochelle lease block production is contracted to the Panhandle Eastern project.

Table 65.—Planned and Possible Mine Capacities in the Powder River Basin Beyond 1991[a]

Operating and permitted Federal mines and undeveloped Federal leases with favorable production prospects for 1991		Undeveloped leases with unfavorable production prospects for 1991 and PRLAs		Non-Federal mines[b]	
Name	Capacity	Name	Capacity	Name	Capacity
All operating and permitted Federal mines	226			With favorable production prospects for 1991	51
Undeveloped Federal leases		Leases		Likely to come into production after 1991	
Antelope	12	Lake de Smet[c]	20	Mobil (Johnson Co.)[c]	11
North Antelope	5	East Wyodak[c]	7	Whitney[d]	1
South Rawhide	12	Pearl[e]	2	Absaloka (II) (Mt)	10
Rochelle	11	Total (leases)	29	Tanner Creek[f]	24
Dry Fork	15			Tongue River II (Mt)[g]	10
East Gillette Federal	15	PRLAs		Tongue River III (Mt)[g]	10
North Rochelle	8	Consol (1)[c]	7	Dominy (Mt)	8
Wildcat[c]	10	Consol (2)[c]	8.5	Bear Tooth (Mt)	2
CX Ranch (Consol) (Mt)	8	Peabody (P4)[c]	4	Total	127
CX Ranch (PKS) (Mt)	4	Total (PRLAs)	20		
Total	326	Total leases plus PRLAs	49		

[a]see tables 58, 81, 63, and 84 for 1991 capacities. (Mt) means mine or lease is in Montana.

[b]In Wyoming, capacities of proposed mines that are not associated with existing Federal lease from various sources (primarily Coal Age, 1981, DOE, 1979, and DOE, 1981) total about 67 million tons. However, closer evaluation of these mine proposals indicates that about 40 million tons of this capacity depends on new leasing of Federal coal and that in several other instances listed capacities exceed the sustainable levels of production when the mine reserves are considered. Mines listed here are only those mines and potential levels of production that could reasonably be expected to occur without new leasing of Federal coal. Capacities listed here were developed in consultation with Gary Glass, Wyoming Geological Survey, Laramie (phone conversation, May 18, 1981).

[c]Production is contingent on onsite development for power generation and/or synthetic fuels.

development at this site is unlikely because of problems with alluvial valley floors, but reserves may qualify for exchange for unleased Federal Coal under provisions in the Surface Mining Control and Reclamation Act of 1977.

[e]High stripping ratios and noncontinuous reserves give this lease unfavorable production prospects in 1991, but the lessee, Shell, has developed a mine plan and wants to keep options open for possible development at a later date. Undeveloped leases with unfavorable development potential are not listed here

[f]Shell has an option to lease reserves in the Tanner Creek area on the Crow reservation, provided Shell Can find a market for the Coal,

[g]Development of the Montco and Tongue River mines in Montana is contingent on construction of the Tongue River Railroad. All these mines could also be affected by the Tongue River unsuitability petition. A larger list of nonfederal mine capacities in Montana (i.e., mine proposals not associated with existing Federal leases) compiled from various sources (see sources for table 86 and table A.3.1, vol. II Wyoming task force report) total about 84.4 million tons, excluding the Fort Union region.

SOURCE: Coal Age, 1981, "New Coal Mine Development and Expansion Survey 1980-1989," Coal *Age,* February 1981. Department of Energy, 1979 *Western Coal Development Morritoring System: A Survey of Coal Mine Capacity in the West,* DOE/TIC-10249 (Washington, DC.: DOE, April 1979). Department of Energy, 1981 *Western Coal Survey A Survey of Coal Minig* Capacity *in the West,* DOE/RA-0045/1 (Washington, D. C.: DOE, January 1981). Western Coal Planning Assistance Project, 1979 *Fact Book for Western Coal/Energy Development,* prepared for Missouri River Basin Commission (Billings, Mont.: Mountain West Research, Inc.).

and

- about 19 million tons per year from undeveloped leases (compare with table 63).

For those coal properties unlikely to be in production by 1991, a total of about 125 million tons per year of capacity could perhaps be put in place in the 1990's as follows:

- about 29 million tons per year from three undeveloped leases (compare with table 63);
- about 20 million tons per year from three PRLAs (compare with table 64); and
- about 76 million tons per year from non-Federal mines.

Therefore, an increase of about 150 million tons per year of mine design capacity over 1991 capacity could perhaps become available in the Powder River basin in the 1990's without additional leasing of Federal coal, giving a possible total post-1990 capacity of about 500 million tons per year. This amount should be considered an upper limit rather than a likely value of post-1990 capacity without additional leasing of Federal coal. About 70 million tons would be suitable only for onsite development for synfuels or power generation.

For the post-1990 period, demand projections become very uncertain. The DOE preliminary midlevel production goals, the ICF CEUM midlevel production forecast and the DOE midlevel final production goals for 1995 for the Powder River basin are 382, 306, and 491 million tons per year, respectively. The DOE final production goal, 491 million tons per year, reflects several policies about increased coal use, notably a very large demand for coal for synfuels, that cause the number to be higher than other forecasts. Although all demand projections past 1990 should be regarded as very uncertain, the lower numbers above are, as of now, more likely to be realized.

Implications for New Leasing

Because of the predominance of Federal coal reserves in the West, the decisions of DOI on the quantity, location, and timing of coal leasing are important not only to the Nation in terms of energy availability, but to the region with regard to regional and community development, revenues, and environmental disturbance, There are two distinct philosophies advanced to govern the leasing of Federal coal: 1) a free market approach based on the theory that demand for leases should regulate the rate of leasing, and that the Federal Government should offer leases for development to the extent the market can absorb; and (z) an approach that emphasizes leasing coal at a rate that will ensure that coal production can meet the anticipated demand after considering possible errors in demand projections and delays that might occur in developing the leased reserves. The objective of the second approach is to offer enough coal to meet the projected supply-demand estimates, allowing a moderate margin in excess to meet contingencies for delayed development, underestimates in demand or unforeseen constraints on production. DOI has adopted both of these philosophies at various times in the past,

Because of the leadtime required from the acquisition of reserves to full production, the decisions on the amount, type, and location of coal to be offered for leasing must be made more than a decade in advance. Leasing targets have been based on projected estimates of coal demand, projected estimates of industry's production capacity, environmental considerations, and the potential impacts on the social and economic structure of the coal regions. Because leasing targets are based on forecasts and projections, which in turn rely on assumptions and estimates of production factors and projected demands, there are significant uncertainties in setting the quantities and timing of leasing targets. Experience suggests that supply-demand forecasts are subject to significant errors when extended beyond 5 years, and uncertainties become substantial in projections beyond a decade. (See ch. 5, Markets, for a discussion of these factors.)

Some of the uncertainties that may influence the supply and demand for Western coal during this decade are: Will electricity demand growth remain at current low levels? How rapidly will foreign exports of Western coal grow during next two decades? How rapidly and to what extent will the conversion from oil and gas to coal take place? To what extent will rising transportation costs restrict the market areas for Western coal? Will synthetic fuels development place substantial demands on the Western coal region? To what extent will the mandatory scrubbing requirements of the Clean Air Act restrict demand for Western coal? Will there be unforeseen delays in mine development and the attainment of full production capacity?

Both those who advocate large-scale renewed leasing of Federal coal lands and those who oppose renewed large-scale leasing as being unnecessary at this time use supply-demand projections and the potential of current leased reserves as arguments to support their respective positions. The disagreements between these two groups are based on:

1. differences in what constitute reasonable projections of demand for Western coal;
z. differences in estimates of the time required for bringing a mine into produc-

tion at full capacity;

3. differences over the acceptable levels of leased reserve inventories needed by an operator to ensure competiveness; and
4. differences concerning the safety margins in leased reserves needed to meet contingencies for higher-than-predicted demands or to meet shortfalls in supplies from other regions.

Many industry representatives discount the efficacy of leasing targets altogether. They subscribe to the philosophy that public resources should be freely available to the private sector for development in accordance with the demands of the marketplace. As one spokesman for this philosophy puts it, “the level of leasing can be safely left to those who can be punished economically by errors in judgment and rewarded by sound forward thinking.<’ However, industry agrees that reasonable performance standards and environmental protection standards are necessary to prevent irreversible damage to the environment and the socioeconomic structure of the communities.

Background

Under the leasing program adopted by the Carter administration, coal leasing targets are established in a three-part process: DOI, which has primary responsibility for administering the coal leasing program on Federal lands, uses DOE regional coal production goals as a point of departure. Preliminary leasing targets established by DOI are then reviewed by Regional Coal Teams, which adjust the target based on public comments and the position of the affected States represented on the team. The Secretary of the Interior than approves a specific coal leasing target after reviewing the options presented in a Secretarial Issue Document (SID). The Secretary may select one of the suggested options or substitute one of his own.

DOI has changed its basis for determining leasing targets several times with respect to DOE regional coal production goals. DOI originally used the 1987 medium production goals increased by 25 percent for contingencies. Subsequently, DOI adopted DOE’s midlevel production goals for 1990 but these were later supplanted for the powder River basin by the 1990 high production goals. DOI is currently considering deemphasizing the DOE’s production goals, and using them as just one factor in lease sale planning. In place of total reliance on these production goals, DOI may adopt an approach that would allow primarily the market demand for leases to determine when and where and a t what level lease sales would be held. In order to simplify and expedite the leasing process, consideration is also being given to revising the planning process to defer the determination of mining suitability and other land use planning functions until after leasing. DOI is considering working towards having an inventory of reserves under lease that could support levels two to four times anticipated production, similar to the customary practices of the industry.

In making the decision to use the 1990 high production goals of DOE for the Powder River basin lease sale, DOI acknowledges that currently planned production will exceed demand through 1990. The new Federal coal management program was implemented in June 1979, and will not be fully operational until 1984 at the earliest. one lease sale was held in January 1981, in the Green River-Hams Fork region. Other regions selected for early leasing include:

1. the Powder River basin:
2. Uinta-Southwestern Utah: and
3. Southern Appalachia.

The lease sale in the Powder River basin is scheduled for early 1982. Since the decision to hold start-up lease sales was announced, some have expressed doubts about the necessity of the 1982 sale in the Powder River basin to meet reasonably anticipated demand in the 1990’s given the leases outstanding, available private coal reserves and industry’s present overcapacity in the Powder River basin.

OTA estimated that presently operating and proposed new mines in the Powder River basin, both Federal and non-Federal, would have a total mine design capacity of 350 million tons of coal annually by 1990. (See fig. 37 and tables 58, 61, and 63.) This contrasts with OTA's "most likely" demand for Powder River basin coal, which was estimated to be between 200 million tons and 226 million tons in 1990. (See this chapter, pp. 171-173 and ch. 5, pp. 100-108.) DOE's interim midlevel production goal for 1990 is 275 million tons per year—significantly higher than OTA's "most likely" range. DOE's final midlevel production goal is even higher—295 million tons. The final high level production goal for 1990, which is the basis for the Powder River basin coal sale, is 412 million tons per year.

On June 25, 1981, DOI announced that it had selected a coal leasing target of 1.4 billion to 1.5 billion tons of reserves for the Powder River basin to be considered along with alternative levels analyzed in the regional EIS. This target was recommended by the regional coal team; however, at the time the target was announced, the Assistant Secretary for Land and Water Resources commented that:

> I am apprehensive about setting a leasing target that is too low, that would hinder operation of the market, and that would result in an insufficient amount of coal being leased to satisfy the demand for reserves in the region.[4]

The Secretary of the Interior, at the time he makes the final determination on the Powder River basin lease sale, could decide to lease up to 2.5 billion tons of reserves in the region. Currently leased coal reserves in the Powder River basin total 9.2 billion tons.

Existing leases in the Powder River basin include over one-half of the 16.5 billion tons of Federal coal reserves presently leased. With the additional leases scheduled for 1982, the Powder River basin has become the focus for debate over the timing, pace, and extent of Federal coal leasing needed to meet the future energy demands of the Nation.

Those opposed to renewed leasing in the Powder River basin cite the potential for overcapacity in the early 1990's as the main reason why large-scale leasing scheduled for 1982 should be deferred until, perhaps, 1985. * But given the necessary leadtime to develop a large new mine and reach full production, new leases sold in 1985 could not confidently be expected to reach full capacity until 1995. By 1995, the excess capacity probable in the early 1990's may have been substantially reduced and possibly have disappeared. Estimates of potential capacity and demand in the post-1990 period are considerably less reliable than similar estimates for 1990. An additional 155 million tons per year of capacity over the 350 million tons per year of capacity cited above could perhaps become available in the post-1990 period from some undeveloped Federal leases, PRLAs and new non-Federal mines (see table 65).

About 70 million tons per year of the additional post-1990 capacity would be suitable only for onsite development for synfuels or steam electric use because of low coal quality. Therefore, the 155 million tons per year should be considered an upper limit rather than a likely value of additional post-1990 capacity without additional leasing of Federal coal. For the post-1990 period, demand projections are very uncertain.

The ICF CEUM[5] midlevel production forecast, the DOE preliminary midlevel production goals, and the DOE midlevel final production goals for 1995 for the Powder River basin are 306, 382, and 491 million tons per year, respectively. The DOE final production goal, 491 million tons per year, reflects several policies about increased coal use, e.g., coal for synfuels, that cause the forecast to be higher than others. Although all demand projections past 1990 should be regarded as very uncertain, the lower numbers above are, as of now, more likely to be realized,

[4]Department of the Interior, News Release, June 25, 1981.

*The debate focuses on large-scale leasing. Leasing in special circumstances, e.g., to maintain production or to avoid bypassing a small area of Federal coal that could not subsequently be economically mined, engenders far less controversy.

[5]Coal Electric Utility Model Forecasts and Sensitivity Analyses of Western Coal Production, prepared for Rocky Mountain Energy Co. (Washington, D, C.: ICF, Inc., November 1980).

The pros and cons of the proposed Federal leasing schedule are discussed in the following sections, using the Powder River basin as a case example.

The Case in Support of Large-Scale Leasing in the Near Future

Proponents of "start-up" leasing and full-scale leasing programs in the near future cite four basic reasons for their position:

1. to be able to compensate for the contingencies of increased demand or shortfalls in supply;
2. to ensure competition;
3. to provide additional reserves for production in the post-1990s to accommodate the 10 year (or longer) leadtimes needed to achieve full production;* and
4. to allow entry of operators not now active in the Powder River basin for equity and to stimulate competition.**

Proponents of immediate Federal leasing contend that leasing targets should be geared to allow margins for unanticipated increases in demand or unforseen shortfalls in production because of the failure of some planned capacity to come on line. For example, if only 6 out of the 17 undeveloped properties contributing to the 350 million tons per year of capacity in 1990 should fail to be developed, capacity in that year could be reduced by as much as 60 million tons per year, to 290 million tons per year. Moreover, the "most likely" demand range for Powder River basin coal in 1990 of 200 million to 225 million tons per year implies a midrange estimate based upon judgments of reasonable expectations.

*Eslimates of the time required after lease sale to achieve full production for a large surface mine range from under 10 years to more than 15 years. The upper range reflects a conservative view of the time needed to scale up to full production after production has commenced: the lower range arises in part from the belief that permitting times will become shorter as mine operators and Government regulators alike develop more familiarity y with the permitting process.

**There are 38 lease blocks in the Powder River basin containing 73 leases. There are 19 lessees: 11 oil companies. 3 utilities, Peabody Holding Co., and four others (see app. B, OTA Working Lease List),

The 1990 demand for Powder River basin coal could be somewhat higher than OTA's "most likely estimate"' if several events were to occur:

- if electrical demand grew faster than anticipated;
- if boiler conversions from oil and gas to coal occurred more rapidly than expected;
- if synthetic fuels development came online faster than projected;
- if foreign export of coal grew more rapidly than anticipated; or
- if Powder River basin coal captured an even larger share of the domestic market than anticipated.

Leasing proponents claim that underleasing would have a substantial impact on the coal markets and would drive up market-clearing prices and force shifts in production to other regions. However, opponents of leasing consider it improbable that coal demand will increase significantly beyond the "most likely" demand projections. They further hold that even if demand increased somewhat or some shortfalls in production developed, these would not be large and the capacity and resources in other regions, including Midwestern coal, could easily make up the difference.

Currently operating Federal and non-Federal mines in the Powder River basin have a planned capacity of 246 million tons per year in 1990. (See tables 58 and 61 (including footnote a) and fig. 37.) Most of the currently operating Federal mines would be operating in 1991 at or near full design capacity. Any demand for Powder River basin coal over the 246 million tons per year level would have to be met by presently undeveloped Federal leases and undeveloped non-Federal coal properties. Some proponents of immediately renewed leasing do not consider the potential of the undeveloped leased lands as certain enough to provide a secure safety margin of production in 1990 in light of the leadtime required from lease sale to full production, A second consideration advanced in support of additional Federal coal leasing in the powder River basin is the potential for stimulating competition within the coal industry. Both the Department of Justice (DOJ) and the General Accounting Office (GAO), in reports issued in 1980, criticized the setting of lease targets as being inefficient and potentially anticompetitive because targets attempt to match the amount of Federal coal leased to the amount required to meet given projected demand. * DOJ'S report concludes that a target leasing system unduly supplants the marketplace as the allocator of coal resources. The report presents two solutions: 1) abandon the setting of targets, and begin leasing on demand, or 2) set lease targets at a level far in excess of the more modest leasing targets used earlier. DOJ has previously contended that doubling or tripling the current targets would be necessary to provide a reasonable margin for error and to promote competition. DOJ also recommends the reevaluation of leasing targets to determine whether it would be preferable simply to lease what industry desires. DOI is currently considering deemphasizing leasing targets in favor of the free market approach as suggested by DOJ. Moreover, the adoption by DOI of DOE high production goals for 1990 for the Powder River basin is consistent with DOJ's second recommendation to provide liberal targets much larger than the one to one production-demand ratios used for lease planning earlier.

However, opponents of near-term large-scale leasing in the Powder River basin contend that the excess in potential capacity in the Powder River basin could ultimately lead to a decrease in competition within the region. Most of the current leaseholders in the Powder River basin are large companies that can afford to take short-term losses; smaller leaseholders or new entrants who may not have large amounts of capital might find it difficult to compete in this situation. This factor is also a cause of concern to some smaller companies that nevertheless support early leasing in the Powder River basin.

DOE has recently analyzed Federal coal leasing activities. One important factor DOE considered was the effect of leasing on the conditions for entry into the coal industry. Insofar as easy entry into the industry affects prices and output as a result of stimulating potential competition from new entrants, it is an important factor in assessing the competitiveness of the industry. For regions such as the Powder River basin, where future mining will depend in large part on the availability of Federal coal, the DOE report found that severe limitations on the availability of Federal coal for lease could create an artificially high barrier to entry as well as shifting substantial market power to present industry participants, In general, new leasing is one method of improving entry conditions, and increasing the number of producers. However, the extent to which the lease sale scheduled for the Powder River basin is likely to increase the number of lessees is unclear because: 1) some present lessees might have an advantage over new entrants in assembling large minable tracts because of their existing leases; 2) other present lessees with large reserves in the Powder River basin might not care to increase their holdings; and 3) the number of tracts to be offered for lease is not yet known.

The third factor cited by those advocating immediate renewed leasing of Federal coal is the need for creating a pool of reserves well in advance of planned production to allow for strategic planning by the industry and to accommodate the 10-year (or longer) leadtime from lease sale to full production.

For flexibility, industry prefers to operate on a reserve base that could support two to four times the anticipated production. Also, industry contends that any leasing targets should be geared to meet the maximum possible demand for coal that could occur within a 15- to 20-year planning horizon. Leasing opponents, on the other hand, believe that such long-range planning and reserve pools are not necessary. They contend that if demand is monitored closely, then leases can be offered when demand trends suggest the need will develop in 10 years or so.

*U.S. Department of Justice, Antitrust Division, Competition in the Coal Industry, November 1980; U.S. General Accounting Office, A Shortfall in Leasing Coal From Federal Lands: What Effect on National Energy Goals? EMD 80-87, Aug. 22, 1980.

If DOI were to eliminate leasing targets as the determining factor in its coal lease planning in favor of a market-oriented program for leasing on demand, the market response still may not result in leasing of reserves that could support production substantially in excess of demand ("overleasing"). Moreover, proponents of a liberal leasing policy or leasing on demand claim that overleasing would not lead to production of coal in excess of demand. The proponents reason that if markets do not exist, the lands would not be developed and therefore socioeconomic impacts and environmental impacts because of additional leasing would not occur.

Those opposing the 1982 Powder River basin lease sale admit that demand uncertainties must be considered in coal leasing planning, but they reject many of the projected demand scenarios as being "extreme assumptions, For example, the DOE final midlevel production goal of 295 million tons per year for the Powder River basin in 1990 includes about 35 million tons per year for synfuels feedstock; this is unlikely to be achieved. A more likely number is under 10 million tons per year in 1990, To remedy the uncertainties in long-range demand forecasts and attempt to bring targets closer to "reasonable" demand expectations, a tracking system has been suggested to improve the accuracy of demand projections as DOI moves closer to coal leasing target dates. Demand projections depend on a number of assumptions concerning electrical growth rate, transportation costs, and other factors. If in 1982 or 1983 the actual electrical growth rate or transportation costs differ significantly from those used to bracket the likely demand range earlier, then the likely range of demand for a given year could be modified with increasing confidence.

The prospect of leasing on demand or using liberal leasing targets raises the question of speculation. Unlike the situation during the previous era of liberal leasing, actual production requirements for diligent development now exist in the Federal Coal Leasing Amendments Act and regulations. * If the demand for Western coal does not increase as rapidly as liberal leasing proponents generally assume, the diligent development requirements could act as a damper on acquiring leases purely for speculation.

Opponents of a liberalized leasing program claim that Federal "overleasing" would reduce the revenues from private, State, and Indian coal because of the predominance of Federal coal in the region and the pressures that this coal would place on the local markets. They also claim that "overleaping"" would depress the bids on new leases to the point where the public would not receive a fair return for its resources.

The Case for Postponing Leasing

Those opposing renewed Federal coal leasing in 1982 in the Powder River basin cite three reasons for deferring the lease schedule:

1. the currently operating Federal and non-Federal mines, plus the good quality properties being actively developed and the PRLAs that may be developed in the future will provide substantially more capacity than will be needed between 1990 and 1995:
2. slower leasing is needed to allow sufficient time for adequate planning for leasing by DOI; and
3. slower leasing would better match the capability of 'the State, regional, and local governments to deal with the socioeconomic impacts of development,

Regarding existing and planned overcapacity, those who favor reconsideration and delay of the 1982 leasing schedule in the Powder River basin cite the finding that the capacity of currently operating mines combined with potential capacity from undeveloped Federal and non-Federal properties that

*1)01 is considering various proposals to presen t to I) OF; to liberalize the diligence requirements for leases issued prior to August 1976.

have favorable development potential could reach 350 million tons per year in 1990. This would be 125 million tons per year more than OTA's estimate of the "most likely" 1990 demand for Powder River basin coal. Even if only 11 out of the 17 undeveloped coal properties were developed, total design capacity would still be 290 million tons per year. Opponents of renewed Federal leasing in 1982 point out that this tonnage substantially exceeds OTA's likely estimate of 200 million to 225 million tons per year.

If leasing of Federal coal were deferred until 1985, the newly leased properties would not be producing at design capacity until about 1995. As discussed above, available demand projections for 1995 are highly uncertain, and range from 306 million to 491 million tons per year. At this time, the lower portion of this range appears more likely. Leasing opponents consider the overcapacity to be sufficient to provide adequate coal to meet demand through 1995 because they believe DOE's targets reflect unrealizable policy objectives. The difficulty in making sound projections beyond 1990 precludes a definitive resolution of the disagreement on supply-demand between the perceptions of the proponents and opponents of additional leasing in the Powder River basin in 1982.

The prospects for significant production from the PRLAs in the 1990's are more speculative. Processing PRLAs will not be completed until 1984. * Until the rights of the applicants are determined, there will be little definitive information about ownership, quantity of coal or quality of the resource. Although the full extent of reserves within the PRLAs is not known with certainty, it is estimated that between 35 million and 60 million tons of coal per year may be minable from such lands throughout the West by 1994. Although PRLAs may contribute to future production, it is unlikely that they will add much production within the next 15 years; their contribution to production capacity in the Powder River basin will probably be limited to about 20 million tons per year or less. (See tables 64 and 65.)

*See ch. 9 for a discussion of PRLAs.

Opponents of the 1982 leasing schedule also contend that a delay to 1984 or beyond would allow more time for DOI to prepare environmental baseline studies and permit detailed consideration of the unsuitability criteria that could possible disqualify some proposed lease blocks. However, recent developments within DOI suggest that under proposed changes in the Federal coal leasing program unsuitability criteria would not be considered in processing PRLAs, and a number of criteria of unsuitability that were applied in the prelease tract selection stage would be deferred until later in the process, e.g., the mine permit stage. Furthermore, it has also been suggested that fewer prelease determinations of the resource base and mining conditions be made and that other planning features be dealt with by the lessee after leasing rather than before. However, both the General Accounting Office[6] and the American Mining Congress[7] have criticized DOI for using inadequate data for land use planning on lease sales.

Those advocating a delay of the 1982 sale also claim that the transitional sale scheduled for the Powder River basin was accelerated to show that coal leasing could resume quickly after the leasing moratorium was lifted and the new Federal coal management program was formulated. Because of this, they suggest, insufficient consideration was given to competitive factors in the selection of leasing tracts. Citing the DOJ report on competition in the coal industry that criticized the leasing program for giving inadequate attention to the pattern of leasing and how existing ownership may influence the competitiveness of upcoming lease sales, opponents of immediate leasing claim that deferral of the 1982 lease sale would permit more time for considering the implication of leasing patterns on competition,

[6]Mapping Problems May Undermine Plans for New Federal Coal Leasing, U.S. General Accounting Office, Dec. 12, 1980.

[7]Charles F. Cook, Vice President, American Mining Congress, "AMC's Recommendations 10 Secretary Watt on Reform of Interior Regulations,'" memorandum, Feb. 17, 1981.

Opponents to the 1982 lease sale in the Powder River basin also feel that the large sale will bias the land-use planning process toward mineral development at the expense of other Federal resources and make it more difficult for Federal surface management agencies to apply effectively the principles of multiple-use and sustained yield to manage public resources,

Finally, opponents of the 1982 lease sale in the Powder River basin claim that by deferring the lease sale until 1984, State, county, and local governments could have time to meet the needs of expanded coal development and plan for the socioeconomic impacts that will result, Federal coal leasing decisions in the Powder River basin can have significant impacts on the local communities and the entire region, Many of the socioeconomic impacts of Federal resource development must be dealt with by State, county, and local governments.

Because of the importance of Federal lands within the basin. the decisions of DOI with regard to coal development will determine, to a large extent, the future of the region, the character of the economy and lifestyle of its residents. Whether the economic growth and social change that will accompany development of Federal coal resources is desirable or undesirable in the context of local and county planning objectives, the Federal Government, according to those opposing accelerated leasing, is obligated to carefully plan and coordinate coal leasing with the capabilities and objectives of the residents of the basin.

Another factor in Federal leasing decisions in the broader sense is to ensure that the benefits and negative impacts of resource development are distributed equitably among the various regions of the country. All of these reasons, according to those favoring delay, can be considered and balanced if sufficient time is given to planning, analysis, and seeking a balance in approaching Federal coal leasing among all coal-producing regions.

CHAPTER 8
Transportation

Contents

List of Tables

List of Figures

CHAPTER 8
Transportation

The existing transportation network in the West was generally adequate to move coal production from Federal leases and private tracts in 1980, although a number of specific bottlenecks have been identified, It will be asked to carry greatly increased quantities of coal in the future. The key link in this network is rail haulage, which handled about 61 percent of Western coal production in 1979 and is likely to originate even more in 1990. Most Federal coal leases are and will be served by rail. The principal constraint that may materialize in moving future production of leased coal to its markets is the willingness of the railroads to invest sufficient capital in time to satisfy demand for increased rail service from all shippers, including Federal coal. The mine-to-market transportation costs of Western coal range from about 10 to over 70 percent of delivered fuel costs and constitute an important factor in developing future demand.

Western coal is mined at a considerable distance from most of the ultimate demand it serves, usually electric utility demand, and is used in very large quantities at low unit cost. Coal production therefore creates a substantial requirement for inexpensive bulk transportation services, Western coal now represents perhaps one-third of all the freight moved in its principal market area.

Utilities are the chief consumers of coal. In 1979 they converted 90 percent of all Western coal production to electricity (table 66). New utility projects are subject to long-term planning, ideally for their entire useful lives. Coal supply, transportation, generating plant siting, and electric transmission are all coordinated, arranged, and fixed. The availability and cost of different modes of transportation will influence the final choices, and thereby shape the future market and transportation network for western coal,

The two most important ways of moving Western coal in 1979 were by rail and wire. Railroads originated* 61 percent of all Western coal production in 1979 (table 66). Most of this coal traveled more than 750 miles, and some was delivered to customers by water, Utilities can also choose to burn coal in nearby or mine-mouth generating plants and distribute the electricity to distant customers through high-voltage transmission wires, In 1979, 36 percent of all western coal production was hauled short distances by truck, tramway, etc., to local generating plants (table 66). Some of this power was consumed locally, but a substantial amount was transmitted over hundreds of miles,

Three major long-distance transportation corridors exist for Federal coal. powder River basin coal flows east by rail to utilities in the middle and upper Midwest. Some of this coal has penetrated Indiana, western Kentucky, and Ohio markets via the Ohio River (see ch, 5; fig. 26.) A second corridor flows from the basin south into Arkansas and Texas. This coal has been shipped entirely by rail, although a coal slurry pipeline is projected to carry 25 million tons per year from the basin to Arkansas on completion in the late 1980's. The third corridor originates in the tri-State area of New Mexico, western Colorado, and Utah. It moves west into Nevada and California. Coal traffic from the northern Rockies west to Oregon and Washington is beginning to increase. Another corridor from Colorado and Utah to southern California may emerge if an export market for Western coal develops in Asia.

Other transport modes will not soon challenge the railroad's dominant position in the transportation of Western coal. Economic and technical considerations restrict the transmission of electricity over distances much beyond 500 miles. However, higher

* Rail-originated coal includes: 1) coal hauled exclusively by rail; 2) coal that is transferred to river haulage; and 3) coal transferred for shipment on the Great Lakes.

Table 66.—Distribution of Coals (bituminous, subbituminous, and lignite) Produced in the Western United States During Calendar Year 1979 (thousands of tons)

	District of origin								
Method of movement[a] consumer use	Western Interior coal province[b]	Colorado and New Mexico[c]	Arizona, California, and New Mexico[d]	Idaho and Wyoming	Utah	North and South Dakota	Montana, Alaska, Oregon, and Washington	Western subtotal	U. S. total
United States									
Electric utilities	33,933	14,659	22,582	68,529	7,098	13,361	36,768	196,930	549,774
Coke plants	170	3,362	—	—	943	—	—	4,475	76,971
Other industrial	3,866	1,457	2,265	3,148	2,492	1,531	482	15,241	67,140
Retail.	89	66	1	188	182	47	99	672	1,908
Miscellaneous	18	19	2	5	37	38	706	825	66,771
Total[f]	38,076	19,563	24,850	71,871	10,753	14,977	38,055	218,145	762,564
United States all-rail									
Electric utilities	3,473	10,519	10,745	50,323	2,071	4,951	22,159	104,241	287,950
Coke plants	170	3,362	·	—	943	–	—	4,475	46,033
Other industrial	1,145	1,346	2,252	3,009	1,735	1,300	421	11,208	37,707
Retail sales	8	28	—	119	30	31	99	315	729
Total	4,797	15,255	12,998	53,451	4,778	6,282	22,678	120,239	372,420
River and ex-river									
Electric utilities	177	—	—	4,930	981	–	1,616	7,704	91,100
Coke plants	—	—	—	—	—	—	—	—	18,989
Other industrial	183	1	—	—	—	—	—	184	2,650
Retail sales	—	—	—	—	—	—	—	—	31
Total	360	1	—	4,930	981	–	1,616	7,888	112,771
Great Lakes									
Electric utilities	—	—	—	—	—	—	5,413	5,413	
Coke plants	—	—	—	—	—	—	—	—	
Other industrial	—	—	—	6	—	—	45	51	
Retail sales	—	—	—	4	—	—	—	4	
Total	—	—	—	10	—	—	5,459	5,469	20,919
Tidewater	—	—	—	—	—	—	—	—	4,881
Truck									
Electric utilities	9,272	4,140	5,622	5,158	2,186	3,746	—	30,124	78,005
Coke plants	—	—	—	—	—	—	—	—	3,674
Other industrial	1,278	109	13	134	758	26	16	2,334	21,862
Retail sales	80	38	1	65	152	16	—	352	1,107
Total	10,631	4,287	5,636	5,357	3,096	3,788	16	32,811	104,649
Tramway, conveyor and private railroad									
Electric utilities	21,012	—	6,214	8,118	1,860	4,664	7,580	49,448	77,875
Coke plants	—	—	—	—	—	—	—	—	1,081
Other industrial	1,259	—	—	—	—	206	—	1,465	1,465
Retail sales	—	—	—	—	—	—	—	—	—
Total	22,271	—	6,214	8,118	1,860	4,870	7,580	50,913	80,422

[a] Data may not add because of rounding.
[b] This province includes all of Kansas, Missouri, Texas, and Oklahoma counties of Coal, Craig, Latimer, Muskagee, Okmulgee, Pitt.sburg, Rogus, Tulsa, and Wagoner.
[c] Includes all of Colorado, and those counties in New Mexico not listed in footnote d.
[d] Includes all of Arizona and California, and the following counties in New Mexico: Grant, Lincoln, McKinley, Rio Arriba, Sandoval, San Juan, San Miguel, Sante Fe, and Socorro.
[e] Miscellaneous includes railroad fuel, Great Lakes vessel fuel, Great Lakes commercial docks, coal used at mines and sales to employees, and destinations and Consumer use not revealable, and exports.
[f] Includes exports.

SOURCE: Data taken from U.S. Department of Energy, *Bituminous and Subbituminous Coal and Lignite Distribution Calendar Year 1979* (Washington, D. C.: DOE, Apr. 21, 1980), table 1, pp. 7-11.

voltage transmission lines could increase the economic shipping distance of mine-mouth power, and bulk power is likely to be "wheeled" to more distant consumers in the future. Coal slurry pipelines can compete with railroads over some routes but all the projects presently proposed would carry less than half the coal railroads carry now.

Current Transportation Patterns for Western Coal

The distribution of Western coal production in 1979 between end uses and means of transportation is presented in table 66, Electric utilities consumed 9O percent of all Western coal (197 million tons). Of that amount, 104 million tons—or 53 percent of the utility-consumed coal—was hauled by rail; 4 percent by river; 3 percent via the Great Lakes; 15 percent by truck; and 25 percent by tramway, conveyor, or private railroad. Most of the utility-consumed coal that was moved by rail, river, and Great Lakes traveled at least 750 miles. The coal described as transported by water had to travel 500 miles or more by rail to reach a connecting point. The longest all-rail hauls are about 1,800 miles. Coal burned in mine-mouth plants and short-haul coal is typically moved by conveyor, truck, or private railroad. Much of the electricity produced by this locally burned coal is shipped by wire over distances up to several hundred miles. Coke plants used only 2 percent of the West's coal production in 1979, and all of that was hauled by rail. Other industrials consumed about 7 percent of Western coal, almost three-quarters of which was moved by rail, Fewer than 1 million tons was sold as a retail product or used for miscellaneous purposes. Railroads moved 55 percent of Western coal output exclusively, and connected with water for an additional 6 percent.

Table 67 presents origin and destination data for Western coal production in 1979 by district of origin and State of destination. In this table, destination means where the coal was consumed, not where resulting electricity may have been consumed. Thirty States consumed Western coal in 1979. Table 68 displays dependence on Western coal for each of the 30 States. The degree of dependence not surprisingly was related to the distance from the Western coalfields: the further the consumer market, the less dependency on Western coal. Western coal's penetration into Ohio, Indiana, and Illinois has been related to sulfur-emission standards, which make Western low-sulfur coal attractive despite the distance and the cost. This market should continue for older plants, but new source performance standards (1979) may make local coals more attractive to utilities in these States.

Table 69 ranks these 30 States according to how much Western coal each consumed in 1979, Texas was by far the largest consumer; more than half of its consumption was mined locally and shipped a short distance. However, the powder River basin shipped about 11.6 million tons to Texas by rail. Most of the 16 million tons that Wyoming consumed was mined locally, for customers such as mine-mouth plants, All of Illinois' 15,2 million tons was shipped by rail, most of it from Wyoming and Montana. Most of Minnesota's 12.8 million tons was hauled by rail from Montana. Kansas, Iowa, and Nebraska tapped the powder River basin via rail for their coal. North Dakota used mostly locally mined coals. Colorado and Arizona consumed local coals hauled by rail. Little coal moved west to the Pacific rim.

Table 67.—Distribution of Coals (bituminous, subbituminous, and lignite) Produced in the Western United States in Calendar Year 1979 by District of Origin and Method of Movement (tonnage in thousands of tons)

				District of origin						
Geographic division, State of destination	Total shipped to receiving State	Total originating from Western Coal District (and percent of State total)[a]		Percent from Western Interior coal province	Percent from Colorado and New Mexico[c]	Percent from Arizona, California, and New Mexico[d]	Percent from Idaho and Wyoming	Percent from Utah	Percent from North and South Dakota	Percent from Montana, Alaska, Oregon, and Washington
Ohio	72,804	3,835	(5%)							
River		5%					5			
Indiana	52,320	5,000	(9.6%)							
Rail		7.7%			2.3		2.3	0.5		2.4
River		1.9%						1.9[e]		
Illinois	42,719	15,297	(36%)							
Rail		35.7%		Neg	4.1		15.4	0.4		15.7
River		0.1 %		0.1						
Michigan	32,385	4,353	(13.4%)							
Great Lakes		13.4%								13.4
Wisconsin	15,192	5,546	(36.5%)							
Rail		31.5%					17.5			14
River		4.8%								4.8
Truck		0.1		0.1						
Minnesota	14,225	12,786	(90%)							
Rail		77.3%		Neg	Neg		Neg		9.2	68
River		4.6%		0.2						4.4
Great Lakes		7.8%					Neg			7.8
Truck		0.2%		0.1						Neg
Iowa	13,571	9,382	(69%)							
Rail		61 %		3.4	4.5		52	Neg		0.8
River		5.7%					3.8			1.8
Truck		2.3%		2.3						
Missouri	24,356	9,339	(38%)							
Rail		22.9%		9.8	3.7	1.1	8.3	Neg		
Truck		10.5%		10.5						
Tramway, etc.		4.9%		4.9						
North Dakota	11,050	11,049	(1 00%)							
Rail		21.6%					Neg		21.6	
Truck		34.3 %							34.3	
Tramway, etc.		44%							44	
South Dakota	2,912	2,911	(100%)							
Rail		94.7%			0.2		5.8		89	
Truck		5.3%					5.3			
Nebraska	4,929	4,929	(1OO%)							
Rail		100%		Neg	8.4		86	5.6		Neg
Kansas	9,640	9,634	(99.9%)							
Rail		83%		6.7	3.9		72	0.1		
Truck		17%		17						
Florida	6,193	33	(0.5%)							
River		0.5%		0.5						
Tennessee	28,703	Neg[f]								
Alabama	25,989	Neg[f]								
Mississippi	2,820	957	(34%)							
Rail		33 %		Neg	24			9.5		
River		1%		1						
Arkansas	1,988	1,940	(98%)							
Rail		84%		6.3			78			
River		3.8%		3.8						
Truck		9.6%		9.6						
Oklahoma	4,854	4,834	(99.6%)							
Rail		95%		3	0.2		92			
Truck		4.9%		4.9						
Texas	41,090	40,228	(98%)							
Rail		32.6%		2.3	1.6	Neg	24			4.4
River		0.2		0.2						
Truck		13.8%		13.8						
Tramway, etc.		51.3%		51.3						
Colorado	13,251	13,046	(98.5%)							
Rail		67%			43		23	Neg		
Truck		32%			32			Neg		

Table 67.—Distribution of Coals (bituminous, subbituminous, and lignite) Produced in the Western United States in Calendar Year 1979 by District of Origin and Method of Movement (tonnage in thousands of tons) —Continued

Geographic division, State of destination	Total shipped to receiving State	Total originating from Western Coal District (and percent of State total)[a]	District of origin: Percent from Western Interior coal province	Percent from Colorado and New Mexico[c]	Percent from Arizona, California, and New Mexico[d]	Percent from Idaho and Wyoming	Percent from Utah	Percent from North and South Dakota	Percent from Montana, Alaska, Oregon, and Washington
Utah	6,797	6,796 (100%)							
Rail		27.3%		18.3		0.4	8.5		
Truck		45.3%		Neg		0.8	44.5		
Tramway, etc.		27.4%					27.4		
Montana	3,731	3,730 (100%)							
Rail		32%		0.8		3.5	1.2		26.3
Truck		0.3%				0.2			0.1
Tramway, etc.		68%							68
Idaho	516	516 (100%)							
Rail		96%		2.1		81	13		
Truck		3.9%					3.9		
Wyoming	16,005	16,005 (100%)							
Rail		17%				16.5	0.3		
Truck		32%				32	0.3		
Tramway		51%				51			
New Mexico	8,702	8,702 (100%)							
Truck		29%		1	28				
Tramway		71%			71				
Arizona	12,878	12,878 (100%)							
Rail		100%		4	95		1		
Nevada	4,303	4,303 (100%)							
Rail		25%		2		Neg	23		
Truck		75%			75				
Washington	5,664	5,643 (100%)	0.3	0.2		2.3	7.7		
Rail		10.5%							
Tramway, etc.		89.2%							89.2
Oregon	243	242 (100%)							
Rail		100%	2.8	0.8		89.7	6.2		
California	2,735	2,730 (99.8%)							
Rail		99.8%		37.6	11	51			
30-State total	482,565	216,644 (45%)							

[a] percentage ma, not add due to rounding, Neg indicates negligible coal tonnage.
[b] This province includes all of Kansas, Missouri, Texas, and Oklahoma counties of Coal, Craig, Latimer, Muskogee, Okmulgee, Pittsburg, Rogus, Tulsa, and Wagoner.
[c] Includes all of Colorado, and those counties in New Mexico not listed in fotnote d.
[d] **Includes all of Arizona and California, and the following counties in New Mexico: Grant, Lincoln, McKinley, Rio Arriba, Sandoval, San Juan, San Miguel, Santa** Fe, and Socorro.
[e] River transport accounts for only a portion of the route; coal is shipped by rail to barge terminal.
[f] Delivery is by river

SOURCE: DOE, *Bituminous and Subbituminous Coal and Lignite* Distribution *Calendar Year 1979* (Washington, D. C.: DOE, April 1960). Table 3, pp 27-67.

Table 68.—Western Coal Consumed as Percent of Total Coal Used in the 30 States Consuming Western Coal, 1979

Less than 10%	11 to 25%	26 to 50%	51 to 75%	76 to 100%
Ohio 5%	Michigan. 13%	Illinois. 36%	Iowa 69%	Minnesota 89%
Indiana 1O%		Wisconsin 36%		Arkansas 98%
Alabama . . . . . . O%		Mississippi. 34%		Oklahoma. 100%
Florida 1%		Missouri 38%		Texas 98%
Tennessee. . . . . O%				Colorado. 98%
				Utah 100%
				North Dakota 100%
				South Dakota 100%
				Nebraska 100%
				Kansas 100%
				Montana 100%
				Idaho. 100%
				Wyoming 100%
				New Mexico 100%
				Arizona 100%
				Nevada 100%
				Washington 100%
				Oregon 100%
				California 100%

SOURCE: Calculations derived from DOE data in table 67,

Table 69.—Destination of Western Coal Production in 1979 (millions of tons)

Geographic division	Less than 3 million tons/year	3 million to 5 million tons/year	5 million to 10 million tons/year	10 million to 15 million tons/year	15 million tons plus/year
East North Central		Ohio . . . . . . .3.8 Indiana. .. ..5.0 Michigan .. .4.3	Wisconsin 5.5		Illinois .. .15.2
East South Central	Alabama . . . . . . Neg. a Mississippi. .. .1.0 Tennessee. . . . . Neg.[a] Florida . . . . .0.01[b]				
***West North* Central**	**S.** Dakota 2.9	Nebraska. .,4.9	Iowa . ...9.4 Missouri 9.3	Minnesota .. .12.8 N. Dakota. .. .11,0 Kansas. 9,6	
West South Central	Arkansas 1.9	Oklahoma ..4.8			Texas. .. .40.2
Mountain	Idaho. ... , ...0.5	Montana .. .3.7 Nevada 4.3	Utah . ...6,8 New Mexico .. .8.7 Washington .. .5.6	Colorado .. ..13.0 Arizona. 12.9	Wyoming .16.0
Pacific	Oregon ., ...0.2 California 2.7				

[a]Negligible tonnage.
b Florida is grouped in this category for convenience

SOURCE: Office of Technology Assessment, derived from DOE, *Bituminous, and Subbituminous Coal and Lignite Distribution Calendar Year 1979* (Washington, D. C,: DOE, April 1960).

Rail: Capacity Assessment

Railroads carry most leased coal because rail is the only transportation mode currently available to move large quantities of coal away from leases. In most cases, a mine is served by a single rail line.[1] Rail transport is also an efficient, available way to move the coal over long distances to major consumers.

Western rail lines are adequate to handle current coal shipments. Car shortages and traffic bottlenecks were a problem in the past, but the National Coal Association has not heard similar reports for more than a year.[2]

Railroads are expected to maintain their dominant position in the transportation of Western coal, The ability of Western railroads to handle increased future production of Federal coal will be influenced by: demand for rail services to transport Federal coal, non-Federal coal, and noncoal commodities; the capacitities, condition, location, and utilization of rolling stock, tracks, and loading and unloading facilities; and the management, investment policies, and financial characteristics of rail carriers, shippers, and utilities.

Physical Capacity

Future Western coal traffic may stretch the physical capacity of the railroads. The National Energy Transportation Study (NETS) predicted a ", . . potential shortfall in the capacity of the Nation's railroad system as it now exists to move the 1990 predicted coal traffic particularly in the West."[3] congestion was projected to occur at almost 50 Western rail links in 1990, and a smaller number of congested links were identified for 1985 at lower coal traffic. The l990 capacity shortfall assumes that Western coal shipments by rail increase from about 97 million tons in 1975 to 625 million tons, and that no new rail investment occurs other than that already underway as of 1979 -1980.4 More recent Department of Energy (DOE) coal production forecasts show smaller increases in Western coal traffic, projecting that the NETS 1985 traffic level will not be reached until nearly l990. This would give the railroads much more time to improve their facilities.

Several problems in the physical plant of the Nation's railroads have been identified which bear on Western rail capacity. Limited locomotive-manufacturing capacity may prove to be one constraint because expected locomotive requirements in 1990 for all rail needs are "substantially in excess of current fleet size," according to the ICC.[5] A doubling of the current national 28,000 locomotive fleet is estimated to be needed by l990, which would require a 15- to 20-percent growth in locomotive-manufacturing capacity annually, While some excess capacity in locomotive manufacturing is currently reported to exist, heavy demand for locomotives may tax the capability of this sector to respond.

The adequacy of the hopper-car fleet may be another question mark. The Association of American Railroads (AAR) estimates that 285,000 cars, 80 percent of the open-top hopper fleet, were dedicated exclusively to coal. The fleet averaged 84.5 tons capacity and 25.5

[1] The National Coal Association (NCA) estimates that 85 to 90 percent of Western coal production is "captive" to a single carrier. The Association of American Railroads (AAR) claims there is no merit in NCA's assertion. "Such an assessment overlooks competition among railroads, among different coal-producing areas—served by competing railroads—and competition with other sources of energy, " according to William H. Dempsey, president of AAR. DOE could not come to any firm conclusions regarding possible anticompetitive effects of railroad involvement in Western coal, although it warned of "possible" problems if coal is leased to the Burlington Northern. Department of Energy, Coal Competition: Prospects for the 1980s, *Draft Report* (Washington, DC.: DOE, January 1981), pp. 270-291.

[2] Telephone interview with Joseph Lema of the National Coal Association, March 1981.

[3] U.S. Departments of Energy and Transportation, National Energy Transportation Study: A Preliminary Report to the President (Washington, D. C.: DOE/DOT, July 1980), p. iii (hereinafter INETS).

[4] Ibid., pp. 34, 37.

[5] International Commerce Committee, Ex Parte No. 347 Western Coal Investigation-Guidelines for Railroad Rate Structure (Washington, D. C.: ICC, 1979).

trips each in 1979.[6] With these figures, AAR calculated the 1979 theoretical capacity of the coal fleet at 616 million tons, 23 percent in excess of the **500** million tons estimated to have been originated on both major and lesser railroads. However, the average coal car made 23 rather than 25 trips in 1979 (with 45 maintenance days), thereby reducing calculated fleet capacity to about 555 million tons, an excess of 11 percent rather than 23 percent. It is difficult to determine whether the average coal car made fewer trips than the fleet average because of lack of demand or operational difficulties.

Unit trains haul most Western coal and almost all Federal coal. These trains typically consist of 100 100-ton hopper cars that shuttle exclusively between a mine and a utility. A growing percentage of these cars—now about 40 percent—are owned by the utilities themselves. The amount of rolling stock needed in the next decade will depend on coal demand and the time needed to complete **a** unit train cycle—loading, hauling, unloading, and return. The shorter the cycle, the fewer cars are needed, other things being equal. Cycle time, which ranges from several days to 14 days or more,[7] is a function of the efficiency of the loading and unloading facilities, rolling stock, roadway, and traffic control systems. unit trains typically experience shorter cycle times than mixed-freight trains—most Burlington Northern (BN) unit trains make their roundtrips in 4 to 7 days[8]—and their utilization is generally much higher.[9] The coal fleet could be stretched by future coal traffic if current overcapacity is-taken as a sign to reduce future car orders. If demand for another bulk commodity, e.g., grain, were suddenly to rise, coal cars owned by the railroads might be quickly converted. This kind of situation encourages utilities to invest the $45,000/car in buying their own hoppers.

Rail capacity did not present a problem in 1980 as the growth in coal demand slowed and improvements were made in rolling stock and roadways. Three years ago, a number of Western coal shippers reported problems in obtaining hopper cars for mine loadings despite excess capacity on paper. Peabody's Big Sky Mine reported, for example, a shortfall of 200,000 tons—about 9 percent of total planned production in 1978—due to car shortages and scheduling difficulties.[10] A similar situation was reported at ARCO's Black Thunder Mine. Coal car shortfalls forced ARCO to ship less coal than required by its contracts. The cycle time from ARCO's mines to Southwest Public Services' Barrington Station plant in Amarillo, Tex., jumped from 87.5 hours (as stipulated in its 1977 BN contract) to 190 hours in 1978, and the utility was forced to increase the number of unit trains and purchase coal from other suppliers.[11]

The recent slower growth in demand for Western coal has reduced the pressure on the Western railroads. This breathing spell has enabled the rail lines and utilities to have new rolling stock delivered before widespread shortages materialized. The diversification of hopper-car ownership should also benefit coal deliveries by creating less pressure on the rail-owned fleet and by guaranteeing car availability to large utility consumers. When a railroad controls the hopper cars, it controls their distribution and can, if it chooses, favor some shippers. Utility ownership of hopper cars then provides an insurance for the utility that its coal can be shipped.

It does not appear that the reported coal car shortages of 3 years ago had much to do

[6] AAR, "Submission to the interagency Coal Export Task Force," Oct. 2, 1980, p. 14.

[7] Data from the Association of American Railroads indicate that the cycle time of the average coal car was about 14 days in 1979. This figure was derived by dividing 365 by 25.5, the average number of trips per year, according to AAR. See AAR, "Submission," p. 16. The Congressional Research Service calculated a 13-day average coal car cycle several years ago, See U.S. Senate, Committee on Energy and Natural Resources, and Committee on Commerce, Science, and Transportation, National Energy Transportation, Vol. I—Current *Systems* and Movements (Washington, D. C,: U.S. Congress, 95th Cong., 1st sess., 1977), p. 56.

[8] OTA correspondence with Allan Boyce, Assistant Vice-President of Burlington Northern, Feb. 26, 1981.

[9] Willard D. Weiss and Ronald Dunn, "Modern Railroad Concepts for Transporting Western Coal, " a paper presented at Engineering Foundation Conference on Transportation of Fuels for Utility Consumption (Henniker, N. H., 1976), p. 3.

[10] OTA draft report on the Wyoming task force.

[11] Ibid.

with technology, fleet capacity, or railroad finances. Since the railroads have argued that their capacity has always been adequate—indeed, in excess–the shortages that have developed may have been caused by railroad policies regarding maintenance, traffic coordination and the like, and management inefficiencies with respect to planning and investment. It is reasonable to assume that the more Western coal production strains fleet capacity in the future, the greater the role that management policy and management efficiency will play,

Two other major rail infrastructure factors—roadway variables and traffic-control systems—determine the number of trains that can use existing track at any one time. Carrying capacity is related to track configuration, the extent of single and double trackage, the number of sidings, and their length and spacing. Double tracks facilitate fast haulage in both directions, Sidings on a single track allow trains to pass in either direction. The more sidings and the closer their spacing, the more trains can be run on a single track. The longer the siding, the longer the train a track can handle. Traffic control systems determine how close trains can be operated to each other. Automated Block Signals (ABS), a manual system, is less capable than Centralized Traffic Control (CTC), a radio and remote control arrangement, Table 70 estimates the number of coal unit trains that can be run on three different track configurations with a CTC signal system. Longer sidings that are closer together can double the daily train traffic on a single track. Double tracking has three to five times more capacity than a single track.

BN, which originated more than half of the coal hauled by rail in the West, controls three key rail corridors from the Powder River basin:

1. the line east through North Dakota into the North-Central States;
2. the line east through Nebraska and Iowa; and
3. portions of the line south through Colorado and Texas.

Table 70.—Estimated Capacity of Alternative Track Configurations With Centralized Traffic Control (CTC) Signal System

Configuration of rail line	Average number of coal unit trains per day[a]
Single track	
2½ mile sidings, 11 miles apart . . .	20-25
2½ mile sidings, 7 miles apart. . . .	30-35
5 mile sidings, 7 miles apart.	40-45
Alternating single/double track	
10 miles double and 30 miles single track, with 2½ mile sidings	50-55
10 miles double and 10 miles single track	60-70
Double track	70-125

[a] Assurnes a capacity of 10,000 tons per train.

SOURCE: Samir A. Desal and James Anderson, *Rail Transportation Requirements for* Coal Movements *in* 1980 (Cambridge, Mass.. Input Output Computer Services, Inc , 1976), p 2-32.

BN has been upgrading the single track with sidings on its Nebraska line (between Alliance and Lincoln), which had an estimated capacity of 15 to 20 trains per day in the mid-1970's,[12] A CTC signal system with double track and alternating single and double tracks are being installed. The Union Pacific (UP) appears to be better able to transport Wyoming coal east because it double-tracks and uses heavier gage rail.[13] However, the east-west UP line through southern Wyoming and Nebraska does not originate coal from the Powder River basin, which is served exclusively by BN. UP track in Wyoming and Nebraska is divided about equally between CTC and ABS traffic control systems.

Financial Considerations

NETS estimated that all railroads will have to invest $5 billion to $7 billion between 1978 and 1985 in rolling stock to have the capacity to handle all future traffic.[14] Another $4 billion to $5 billion will be needed to upgrade existing track and construct new coal-trans-

[12] Montana Energy Advisory Council, Montana's Major Energy Transportation Systems: Current Conditions and Future Developments (Helena, Mont.: State of Montana, December 1976), p. 49.

[13] Comment from the Wyoming task force, Wyoming Report, vol. 1, p. 63.

[14] NETS, p. 62.

port lines.[15] Inasmuch as most additional coal production will occur in the West, it can be assumed that at least half of these sums will need to be invested there by Western railroads. Recent coal traffic projections indicate that this schedule may be stretched out, but the investment will ultimately be necessary.

Western railroads range from highly profitable to below-average money makers.[16] Table 71 presents company performance data for 11 railroads, assembled by Forbes, The two largest Western coal carriers—Burlington Northern and Union Pacific—both ranked near the top of the list in growth, but were very different in profitability. BN, the major Western coal line, showed below-average profitability measures, but UP profitability was well above average for the railroad industry.

[15] Ibid., p. 64.

[16] The Milwaukee line is bankrupt. A revised reorganization plan will be presented to a Federal District Court on Sept. 15, 1981. Shippers, States, and other railroads are negotiating the purchase of Milwaukee track. BN and UP have acquired about 500 miles so far. Standard and Poor rated Western roads in 1979 as follows: Union Pacific (AAA), Santa Fe (AA), Denver& Rio Grande (A), Southern Pacific (A), Burlington Northern (A), Missouri Pacific (A-), Chicago & Northwestern (B), and Milwaukee (D). A number of mergers are being negotiated that may affect coal haulage, including the Union Pacific with the Missouri Pacific, Burlington Northern with the St. Louis-San Francisco, and the Santa Fe and Southern Pacific.

A railroad’s ability to borrow capital or raise it through stock sales is closely related to its rate of return over a period of time, as well as expectations of future growth. Many Western railroads are subsidiaries of diversified companies who must choose where their capital should be invested. In 1977, return on rail assets amounted to 8.6 percent for the Denver and Rio Grande; 3.3 percent, Burlington Northern; 5.9 percent, Santa Fe; **2.3** percent, Southern Pacific; **7.9** percent, Union Pacific; **5.8** percent, Missouri Pacific.[17] Yet the parent companies of these lines made at least 10 percent on their other assets (nonrail transport, real estate, forest, and natural resources). Table 71 shows a similar comparison between the rail industry and the all-industry medians.

Table 72, which summarizes the coal business of the major Western railroads, indicates that the coal revenues received by the Western roads were low in proportion to coal’s share of their total freight traffic. Coal, for example, made up 44 percent of BN’s total freight in 1978, but accounted for only 24 percent of all of BN’s freight revenues,

[17] NET's, p. 67.

Table 71.—Railroads: Yardsticks of Management Performance

	Profitability								Growth			
	Return on equity				Return on total capital				Sales		Earnings per share	
Company	5-year average	5-year rank	Latest 12 months	Debt/equity ratio	Latest 12 months	5-year rank	5-year average	Net profit margin	5-year average	5-year rank	5-year average	5-year rank
Chicago & North Western	27.1%	1	45.9%	2.2	10.2 %	6	6.6%	4.0%	10.8%[a]	6	20.8%[a]	3
Missouri Pacific	26.7	2	21.8	1.1	10.9	1	11.2	8.0	14.2[a]	4	18.7[a]	5
Union Pacific	13.3	3	15.6	0.3	10.3	2	8.9	8.6	19.5	1	21.0	2
Southern Railway.	12.9	4	14.3	0.6	8.1	4	7.4	10.6	10.6	7	13.3	9
Norfolk & Western Ry	12.6	5	15.1	0.3	9.5	3	7.4	13.6	5.9	11	18.9	4
Santa Fe Industries	10.4	6	13.3	0.3	8.9	5	7.2	9.0	13.4	5	14.3	7
IC Industries.	9.8	7	10.2	0.7	5.7	7	6.1	2.7	19.4	2	13.3	8
St Louis-San Fran Ry	8.0	8	10.3	0.8	6.3	9	5.1	5.3	9.4	8	14.5	6
Burlington Northern.	7.2	9	10.7	0.5	7.0	8	5.2	5.5	14.9	3	25.5	1
Southern Pacific	6.9	10	7.1	0.6	4.8	10	4.9	5.3	8.7	10	6.4	10
CSX	(b)		(b)	(b)	(b)		(b)	6.7	9.2[a]	9	6 1[a]	11
Industry medians	11.5		13.8	0.6	8.5		6.9	6.7	10.8		14.5	
All industry medians	15.8		16.1	0.4	11.0		11.1	5.0	14.3		13.9	

[a]Four year growth.
[b]Not available: not ranked.

SOURCE: *Forbes,* Jan. 5, 19b1, p. 92

Table 72.—Coal Carried and Revenue Received as Percentage of Total Freight for Western Railroads, 1978

	Coal originated		Total coal revenues	
Railroad	Tonnage (million tons)	Coal as percent of all freight	Coal revenues (million dollars)	Coal revenue as percent of all freight revenue
Burlington Northern	63.0	44	$463.7	24
Union Pacific. ... , ...	17.3	26	167.6	11
Denver & Rio Grande	13.2	69	65.7	31
Missouri Pacific	9.2	14	63.8	5
Milwaukee	4.9	19	34.0	8
Chicago & Northwestern .	2.6	6	44.2	8

SOURCE. National Coal Association, *Coal Traffic Annual, 1979 Edition* (Washington, D C. NCA, 1980), p II-8

On the other hand, the unit costs of moving coal are lower than costs for many other commodities. Western coal haulage costs are lowered by the extensive use of dedicated, highly cost-effective unit trains, often owned by the consumer rather than the carrier. Coal shippers, unlike consumers of many other rail-hauled commodities, even build and operate their own loading and unloading facilities. Railroads also use a betterment accounting system, which tends to show lower earnings than would depreciation accounting. These factors mitigate what otherwise seems to be a generally bleak profit picture for coal haulage by Western carriers.

Rail-related capital can be raised in many ways. However, the parent companies of Western railroads may be reluctant to invest their limited capital in new rail capacity if nonrail investments consistently generate greater returns. Consequently, future rail investment and capacity for Federal coal seems to be linked more to the investment priorities of individual railroads than to questions of physical plant, technology, and capital availability. Although sufficient investment has been undertaken to provide adequate capacity for current and future coal traffic over the next few years, constraint on Western coal production could develop by 1990 or 1995 if the railroads decide not to make additional capital stock investment and roadway improvements.

This question of capital application was spelled out in detail by Richard Bressler, President and Chief Executive Officer of BN to Western utility executives, Bressler said:

> One of the first things 1 did at Burlington Northern was to look at where our investments had been made.
>
> Here's what I found. For many years, Burlington Northern has invested more than its cash flow,
>
> . . . and a large part of those investments has gone to coal–into our ability to haul coal from the Powder River basin to you, the utilities. . . .
>
> about $1 billion has been intvested in (coal-carrying) capability so far. Our plans call for the investment of another billion over the next several years.
>
> . . . Last year, the railroad made $41 million before tax, according to our annual report.
>
> $41 million–that's a before-tax rate of return of less than 4 percent on what Burlington Northern recently invested in coal-hauling alone. Less than 4 percent.
>
> I can look at an array of tariffs and figure out that relatively little of that $41 million came from hauling coal,
>
> . . . we at Burlington Northern will be very careful about future investments in coal-hauling capacity—at least until the picture is clear.
>
> Burlington Northern has other good investment opportunities, many solid opportunities.
>
> . . . Burlington Northern is prepared to continue investing in coal capacity. We are prepared to continue our commitment, assuming there is a reasonable return on such investments, (Emphasis in the original.)18

[18] Richard M. Bressler, "Remarks Before the Western Coal Transportation Association" Denier, Sept. 10, 1980.

The unclear picture of the future to which BN's Bressler referred involves future rail rates, coal demand, litigation (utilities have 18 separate suits against BN related to coal-hauling contracts), and slurry pipelines. If an appreciable investment is made in pipelines, BN vice-president Allan Boyce said, the railroad will cut back its coal-related investment.[19]

If return is not sufficient to cover anticipated investment, other financing arrangements—such as borrowing, shipper or customer purchase of hopper cars, shipper construction of roadway, or public subsidy, among others—will be considered. Such arrangements are an increasingly common way of financing new railroad equipment. Rolling stock is normally financed through either leases (often from banks) or equipment trust certificates, which are, in effect, mortgages. Utilities that have long-term coal contracts now frequently finance the hopper cars and locomotives necessary to transport the coal. In some cases, utilities and coal shippers are also providing money to the railroads for improving roadbeds. The Staggers Act of 1980, which partially deregulated the railroads, provides the legal framework for utilities to negotiate long-term contracts with railroads. Coal industry spokesmen believe that customers and shippers will begin to negotiate such contracts because they introduce more predictability into rate and supply issues.

Western railroads have made major capital investments in recent years to meet expected coal traffic. The higher efficiencies that this investment has produced and the slower-than-expected rate of growth for Western coal has resulted in excess coal-haulage capacity throughout the Western rail network. The railroads have argued that the Interstate Commerce Commission's (ICC) rates have not produced sufficient return to continue investment at recent levels. Excess capacity is an inefficient use of capital and tends to inflate rail rates. However, if rail rates are not high enough, additional needed investment will not be made. Rates must cover necessary investment but not excessive overcapacity. Even though excess capacity is now a common complaint among railroad operators, they have argued that ICC rates have not been adequate to meet their needs. For example, Thomas J. Lamphier, president of BN's transportation division, recently wrote:

> Unit train coal traffic requires a heavy-duty rail system in order to withstand the continuous impacts of this heavy tonnage on the rail and roadbed. It also requires long sidings and automated signaling to allow for fast movement of coal trains together with non-coal trains, These requirements involve enormous amounts of capital to be generated from internal earnings and from external sources. Unfortunately, recent ICC and court decisions have produced an uncertain pricing atmosphere to the point where it is doubtful that the revenues permit the recovery of full costs involved in the traffic, much less recovery of the large increases in costs as they arise in today's inflationary environment. (Emphasis added.)[20]

Coal-haul rates vary according to distance, tonnage, and other factors. A representative example is the $20.42/ton cost—$0.0127/ton mile—of hauling Powder River basin coal from Gillette to Smithers Lake, Tex., a distance of 1,607 miles.[21] (Eastern hauls are shorter than Western hauls—generally between 150 and 400 miles—and costlier: the rate for the 346-mile trip from Bluefield, W. Va., to Norfolk, Va., is $12.59/ton, or $0.0356/ton mile.) ICC has approved rate increases for Western coal traffic in recent years, 20 to 30 percent boosts being common since the late 1970's.

On the other hand, utilities say that the current transportation charges, which can amount to over 70 percent of the delivered cost of a ton of Western coal, * are not justi-

[19] 0TA telephone interview with Allan Boyce, Assistant Vice-President of Burlington Northern, March 1981,

[20] Correspondence between Thomas J. Lamphier and Arthur Ingberman of DOE, Aug. 26, 1980, included in AAR's "Submission," p. 23.

[21] Rates included in letter from John S. Reed, Chairman and Chief Executive Officer of the Atchison, Topeka. & Santa Fe Railway Co. to William Dempsey, President and Chief Executive Officer of the Association of American Railroads, Aug. 19, 1980, included in the AAR's "Submission, " p. 20.

*See, for example, table 28 in ch. 5 of this report.

fied by carrier costs. They argue, further, that ever higher rail charges and unreliable service are forcing them to develop other sources of supply and other modes of transportation. Assuming rail transportation costs continue to rise, Western coal customers can be expected to consider shifting part of their purchases to closer suppliers. This constitutes an economic rationalization that may reduce the growth of Federal coal production, or, at least, geographically reapportion Federal production. The ICC's Ex Parte 347 decision on Western rail rates in November 1980 could result in an annual increase in Western coal rates of from 2 to 10 percent annually.[22] The Staggers Rail Act of 1980, which deregulated part of the rail industry, will have little direct effect on Western coal haulage since ICC retains regulatory authority over "market dominant" commodities, of which ICC considers Western coal to be a "classic" example,

[22]Telephone conversation with John Sado, ICC lawyer who was involved in Ex Parte 347, January 1981. Sado emphasized that the 2 to 10 percent figure was a reasonable speculation. Ex. Parte 347 describes the railroads as a "relatively anemic" industry . . . [whose] shortage of internally generated funds has led to the deferment of road maintenance and the delay of road capital . . and an increased reliance on debt and lease obligations. " (Ex. Parte 347, pp. 4-23).

Rail: Constraint Analysis

The major potential constraints on increasing Western coal traffic, other than physical and financial capacity, can be grouped into two categories: socioeconomic problems and environmental-safety problems.

In the past, railroads brought economic life to the communities through which they passed. Today, increasing coal traffic can create serious disruptions in Western communities that are bisected by rail lines carrying heavy traffic. If the line has been a heavy carrier for many years, communities are likely to have adapted or made the necessary investments to resolve delays. Where the increase in traffic occurs suddenly, severe disruption and a lack of resources may combine to create public concern. The ICC noted that:

> increased unit train operations on these [existing Western] routes may reach a level which may disrupt transportation, land use, and social patterns of the residents. . . . It should be noted, however, that unit trains will not create any new or unique impacts, . . . Rather, the same railroad/community problems that have existed in the past may be intensified and what might have historically been regarded as a slight annoyance could potentially develop into a significant community problem.[23]

[23]Ex Parte 347, p. 5-86.

Delay caused by train operation is the major rail-related impact whose disruptiveness could give rise to community opposition and become a constraint on Federal coal development, Heavy unit-train traffic during which dozens of 100-car trains pass through a town for a number of hours each day can interfere with normal business, commuting, emergency vehicles, and school schedules. Several hundred crossings are likely to be affected by increased Western coal traffic and a somewhat smaller number of grade separations are likely to be needed.

Grade separations and improved signaling systems are often prohibitively expensive for local governments to finance. Western States are now surveying their specific needs, NETS discussed alternative sources of financing new highway grade crossings, among which are railroad financing, State funding, and Federal funding (Highway Trust Fund, general revenues, national coal severance tax, and a carrier tax.)[24] NETS did not make a recommendation on this matter but concluded:

> Blocking of grade crossings may become a significant problem both to communities and to the movement of coal. , . . In the absence of solutions, communities may take actions which could affect coal traffic, Local or-

[24]NETS, pp. 70-71.

dinances prohibiting blocking of crossings more than a given amount of time per hour, coupled with speed limits, could adversely affect the efficiency of coal traffic. Legislation before Congress to limit the length of unit trains would actually increase congestion at grade crossings. [25]

Environmental health and safety is a second potential constraint on rail transport. Fatalities and injuries associated with rail haulage are significant, although OTA estimated that a go-percent increase in train traffic would yield a 21-percent increase in death and injuries.[26] Exposure to train noise is a hazard whose seriousness depends on factors such as the location of the rail lines, population density and topographical and architectural configurations. At 50 unit trains per day, OTA estimates, for example, that 165,000 persons from Gillette to Dallas would be exposed to noise levels exceeding the Environmental Protection Agency (EPA) community noise guidelines.[27] Air quality is likely to be reduced somewhat from locomotive emissions of carbon monoxide, hydrocarbons, nitrogen oxides, particulate, and other pollutants associated with diesel-electric engines.[28] Each of these problems could become a constraint on Federal coal were they to reach serious proportions in a number of places at about the same time,

Increased use of Western coal by Pacific Coast States, or the marketing of Western coal abroad, will enlarge the area affected by rail transportation impacts, Socioeconomic, environmental, and safety considerations could pose particular problems for west coast communities which already experience congestion and air pollution problems.

[25] Ibid., p. 69,
[26] Office of Technology Assessment, U.S. Congress, A Technology Assessment of Coal Slurry Pipelines (Washington, D. C.: U.S. Government Printing Office, March 1981), p. 106.

[27] Ibid., p. 109.
[28] Ibid, p. 114, and Ex Parte .347, p. 5-110.

Coal by Wire: Capacity and Constraints

Most Western coal is sold to utilities who convert it to electricity. As indicated by the earlier discussion of table 67, 40 percent of the Western coal sold to utilities in 1979 was delivered to mine-mouth or nearby generating plants by conveyor, truck, etc., while 60 percent was shipped long distances, principally by rail. Because more than 60 percent of the electric demand supplied by Western coal in 1979 was located at long distances from the mines, a large part of the locally generated electricity was shipped by wire to serve that demand. Since the cost and efficiency of generating plants is the same regardless of whether it is coal or coal-fired electricity that is being shipped in bulk, a utility's decision between the two often revolves on transportation factors, such as cost and reliability, and environmental impacts that may prevent siting of new generating plants and transmission lines in certain areas.

Electricity moves from generating plants via high-voltage wires. Bulk power is supplied through lines in excess of 230 kilovolts (kV). * The bulk power is distributed to regional power pools, which are utility-established organizations that regulate the generation and distribution of electricity among pool members to achieve economic efficiencies.[29] Once electricity is fed into the grid, the point of origin and final destination of any particular unit cannot be identified.[30]

* Utilities also transmit and distribute power. Transmission lines are between 70 and 230 kV, and distribution lines are 69 kV and less.
[29] U. S. Senate, Committees on Energy and Natural Resources; and Commerce, Science, and Transportation National Energy Transportation, 95th Cong., 1st sess., publication No. 95-15 (1977), pp. 353-354.
[30] The Federal Energy Regulatory Commission (FERC) collects data on interstate shipments of bulk power from utilities on FERC Form 412, but does not tabulate this information. The U.S. Senate report cited above did organize these data for CY 1974 (Ibid., p. 372).

High-voltage transmission involves losses in transformers, reactors, and lines that normally consume about 6 percent of the power generated at the mine-mouth.[31] Transmission losses increase with distance, and can be reduced by raising the voltage. Present voltages permit efficient power transmission over distances of several hundred miles. Longer distances can be achieved by using higher voltages or by "wheeling," in which a region imports power to supply a portion of its own demand and passes on its own generated surplus.

Different studies have come to different conclusions regarding the relative cost efficiencies of rail v. wire transportation. A 1975 study by the Bureau of Mines compared the two using Powder River basin coal and consumer destination at 1,000 miles southeast from the mine. This study concluded that unit-train haulage would be about 30 percent less costly.[32] DOE's National Power Grid Study found that a mine-mouth generation plan ". . . may offer a 15-percent cost advantage over the local generation plan."[33] High-voltage transmission has a more stable cost structure than rail haulage, which may constitute its principal economic advantage in the 1980's. Its labor and operating costs are minimal.

Burning coal at mine-mouth plants and shipping by wire is an attractive option for many utilities that own both the generating plant and distribution system, and, thereby, are not dependent on independent carriers. It also attracts utilities because of the relative ease of passing along the costs of capital investment compared with the difficulty of negotiating fuel-adjustment increases. Advantages of this sort might also be viewed as potential anticompetitive, cost-increasing developments for electricity consumers.[34]

Large future increases in the amount of Federal coal shipped by wire may be constrained by several factors. The generating plants require large amounts of water, which is used to cool the electricity-generating apparatus.[35] An alternative is air-cooling. Scarcity of water in the powder River basin justified the expense of constructing the first dry-cooling tower in the United States at the Wyodak Power Plant east of Gillette, Wyo.

Water use by plants may limit other economic activity, particularly water-intensive farming. If mine-mouth plants are planned for cluster areas together with synthetic fuel plants, air-quality standards could be exceeded, Constructing mine-mouth plants in the West also presents local communities with problems because of intense but short-term population growth associated with the construction work force. These problems have given rise to local opposition in some cases to expansion of mine-mouth generating facilities,[36]

The transmission lines have also become objects of controversy. Farmers and other landowners have objected to losing right-of-way land (15 to 20 acres are required per mile of transmission line). A direct-current line from a North Dakota lignite mine to Minnesota's Twin Cities was protested by farmers trying to keep the line off their property.[37] Farm opposition is understandable since radial-spray irrigation systems cannot be used in fields under transmission lines.[38] underground burial of these lines can double

[31] DOE, *The National Power Grid Study, Vol. II, Technical Study Reports* [Washington, D.C.: DOE, September 1979), p. 135.

[32] U.S. Bureau of Mines, Division of Interfuels Studies, *Comparison of Economics of Several Systems for Providing Coal-Based Energy to Users 1,000 Miles Southeasterly From Eastern Wyoming Coal Fields—Four Modes of Energy Transportation and Electricity Versus Gas and the End Use Energy Forms* (Washington, D.C.: U.S. Government Printing Office, April 1975).

[33] DOE, *National Power Grid Study, Vol. II*, p. 149.

[34] DOE, *Coal competition*, supra note 1.

[35] *NETS* pp. 80-81. Water-cooled steam-generating plants require 7 to 8 tons of water per ton of coal, compared with 1 ton of water for slurry pipelines and negligible amounts for rail haulage.

[36] Michael Parfit, *Last Stand at Rosebud Creek: "Coal, Power, and People"* [New York: E. P. Dutton, 1980).

[37] Barry M. Casper and Paul D. Wellstone, *Powerline: The First Battle of America's Energy War* (Amherst, Mass.: University of Massachusetts Press, 1981).

[38] Michael J. Murphy, Susanne Maeder, and James I. McIntire, *Northern Great Plains* Cool: Conflicts *and Options in Decision Making* (Minneapolis, Minn.: Upper Midwest Council, 1976), pp. 6-22.

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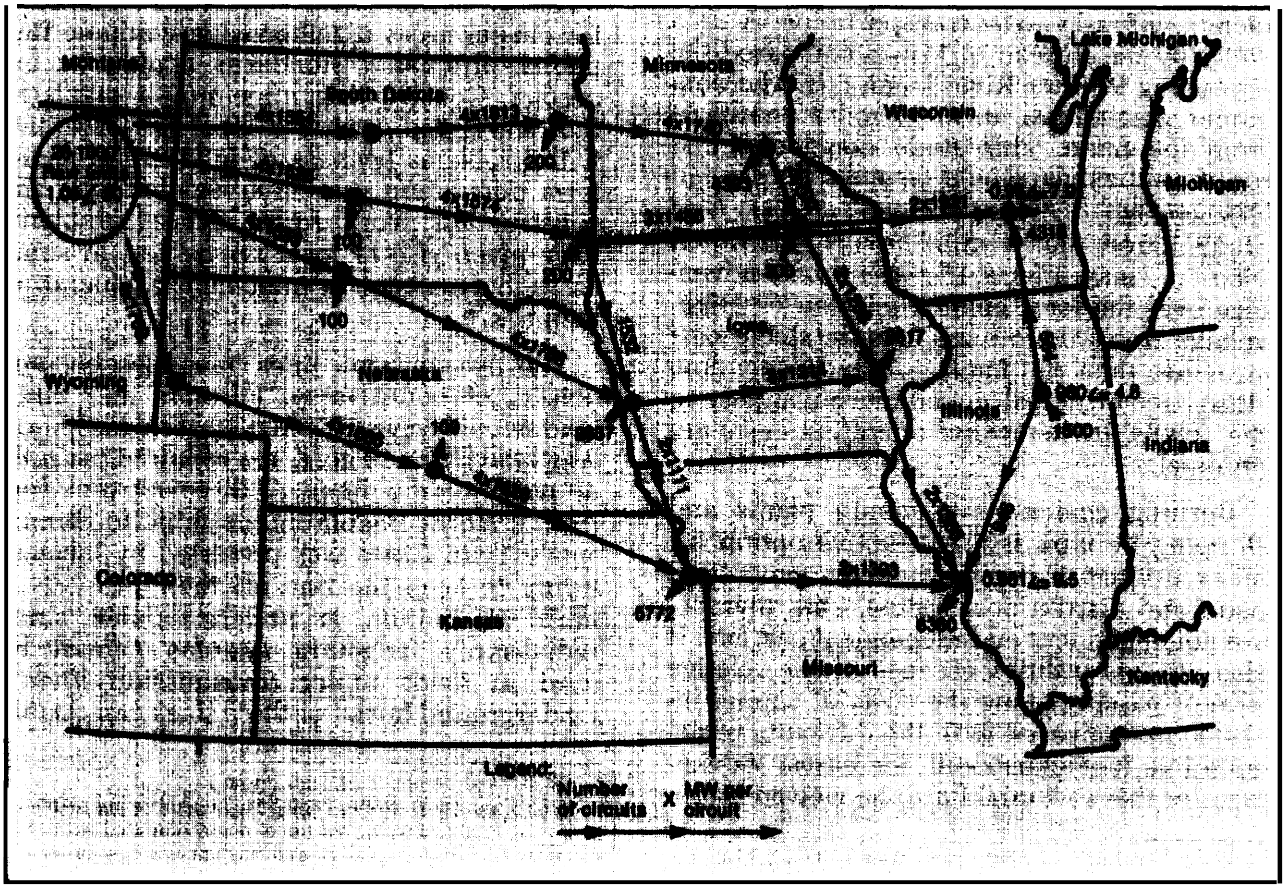
to sextuple the costs.[39] Citizens have also questioned the environmental safety of the electric and magnetic fields surrounding high-voltage lines. Problems associated with corona, noise, spark discharge and ozone have been identified. The long-term biological and health implications of high-voltage transmission lines are not known at this time. However, citizen opposition has made it increasingly difficult for utilities to obtain Western rights-of-way. Construction of a 765-kV system as suggested in figure 38 to handle mine-mouth power could give rise to substantial opposition.

For all these reasons, some industry representatives and environmentalists have urged that it is preferable to site combustion facilities near to the markets for their electricity.

[39] Montana Department of Natural Resources and conservation, Draft Environmental Impact Statement on Colstrip Generating Units 3 and 4, 500 Kilovolt Transmission Lines, and Associated Facilities, Vol. 4, "Transmission Lines" (Helena, Mont.: State of Montana, 1974), p. 37.

Figure 38.—1997 System 765-kV Power Flow



SOURCE: National *Power Grid Study,* p. 133

Truck Haulage: Capacity and Constraints

Trucks hauled almost 33 million tons of Western coal in 1979, 30 million of which utilities consumed. This represented about 15 percent of all Western coal production as well as 15 percent of utility-consumed Western coal,

Coal is trucked to consumers both on and off the public highways. Highway vehicles carry 15 to 30 tons (occasionally more) while off-road trucks can handle up to 150 tons. Trucks are more flexible than other coal-transportation modes. They are a cost-efficient mode for short distances and small quantities of coal, the economical distance varying according to local conditions. One company looking at transportation systems for 5 million tons per year of Texas lignite concluded that truck haulage was limited to a maximum of 10 miles and that truck-rail haulage was cost effective for longer distances.[40] Truck haulage is a simple and familiar technology whose application is generally determined by economic factors, weight limitations on local roads, proximity of mine to consumer, and the like. The physical capacity of truckers to move Federal coal does not appear to represent any constraint on future production.

[40]0TA correspondence with 13. C. Bradley, President of Chaco Energy Co., February 1981.

Truck haulage of coal presents a range of environmental, safety, and socioeconomic problems, particularly where trucks regularly pass through population centers. Noise, dust, and pollution are common causes of citizen complaint. Highway damage is frequently extensive from large coal trucks. More than other coal-transport technologies, trucks are local—the technology itself is familiar and simple; the drivers are local residents who often own or lease the trucks; the impacts are readily seen and understood; and effect is easily related to cause, For such reasons, citizen opposition to extensive truck haulage in a given community may emerge more quickly than opposition to other transportation modes. Even if citizen complaints were numerous, a constraint on Federal production is unlikely to result because most new Federal coal will move by rail or wire.

Waterway-Barge: Capacity and Constraints

Almost 8 million tons of Western coal traveled by river in 1979 and another 5% million tons were shipped on the Great Lakes, Almost all of this tonnage was shipped to electric utilities, and all of it originated by rail, Over half of this coal went to two States, Ohio and Michigan.

The inland waterway system has been constructed and maintained by public authority, the Federal Government, with one exception, Locks are operated by the U.S. Army Corps of Engineers. Lock size is the principal determinant of the extent of river and lake traffic, The main access points for Western coal are: Superior, Wis., on Lake Superior; Sioux City, Iowa, on the Missouri River; and in the St, Louis area on the Mississippi. The Sioux City connection is closest to the Western coal-fields.

Barge haulage is a very inexpensive way of moving bulk commodities. Barge service cost averages 6,86 mills/ton-mile compared with 26 mills for rail.[41] The Reagan administration has proposed to increase the fuel tax for bargelines to 30 cents/gal in 1983, which the administration estimates would add less than 4 mills/ton-mile to the operating cost of the

[41]Telephone conversation with Neil Schuster, Vice-president of the American Waterways Operators, Inc., January 1981. Schuster stressed that these cost estimates were for average revenue for all commodities, and that the costs for coal would be less for both barge and rail, Cost data were for 1979.

barge companies. This would represent a 58-percent increase in average barge service cost, "Four mills per ton-mile is a phenomenal jump, an awfully significant increase, when you're talking six to eight mills to move coal," Anthony Kucera, director of the American Waterway Operators Association, said. "The impact would be incredible."[42] A management consultant recalculated the Reagan proposal for an industry newsletter and found that the fuel tax increase would increase expenses by 5 to 8 mills.[43]

Problems have been noted with the capacity of several locks on the Mississippi-Ohio River systems, which exceed or are close to exceeding design capacity.[44] NETS found future congestion to be likely at Dam 26 at Alton, Ill., and the Gallipolis Lock on the Ohio River unless new facilities are built.[45] The extent of any future constraint depends less on the extent of Western coal movement by barge and more on how much additional barge service is required of other commodities, notably oil products.

[42] Northern Coal, Mar. 11, 1981.

[43] Ibid.

[44] The ICC states that "a waterway reaches capacity when the average delay time at a lock exceeds 150 minutes, " ICC, Ex. Parte 347, p. 4-27 referencing U.S. Department of the Interior, 1979, Federal Coal Management Program, Final Environmental Statement, Vols. I and 2 (Washington, D. C.: Bureau of Land Management, 1979). The problem locks include: Locks 50-53 on the Ohio River; Gallipolis Lock on the Ohio; Locks 26 and 27 on the Upper Mississippi; all locks on the Illinois River; Lock No. 3 on the Monongahela River; and the Winfield Lock on the Kanawha River. The ICC says these locks require "long-term structural solutions through the modification or replacement of existing locks" (p. 4-27).

[45] NETS, p. 74.

Coal Slurry Pipelines: Capacity and Constraints

Coal slurry pipelines have not played a significant role in coal transportation. Only one pipeline is currently operating: the Black Mesa line between Kayenta, Ariz., and southern Nevada that has a 4.8-million-tons-per-year capacity and covers 273 miles. This pipeline handled about 0.6 percent of the coal mined in the United States in 1980.

A number of slurry pipelines have been planned or proposed (fig, 39). Nearest to construction is the Energy Transportation Systems Inc. (ETSI) line that would ship Powder River basin coal to Oklahoma, Louisiana, and Arkansas. It would have a capacity of 25 million tons per year. A recent DOE contractor's report forecast that 70 million to 126 million tons of coal could be pipelined in 1990, which would amount to between 5 and 9 percent of all coal transported.[46] This report concluded that several pipelines were most viable, including Arizona to Nevada; Wyoming to Illinois; Wyoming to Texas; Wyoming to Arkansas, Oklahoma, and Louisiana. OTA's investigation reported that coal slurry pipelines "... do represent under some specific circumstances the least costly available means for transporting coal measured in economic terms."[47] On the other hand, the construction of a number of Western pipelines would directly affect the investment and capacity decisions of competing railroads. Coal slurry pipelines involve much more complex engineering than gas or oil pipelines and they are not without environmental and social costs of their own.[48] This report also concluded:

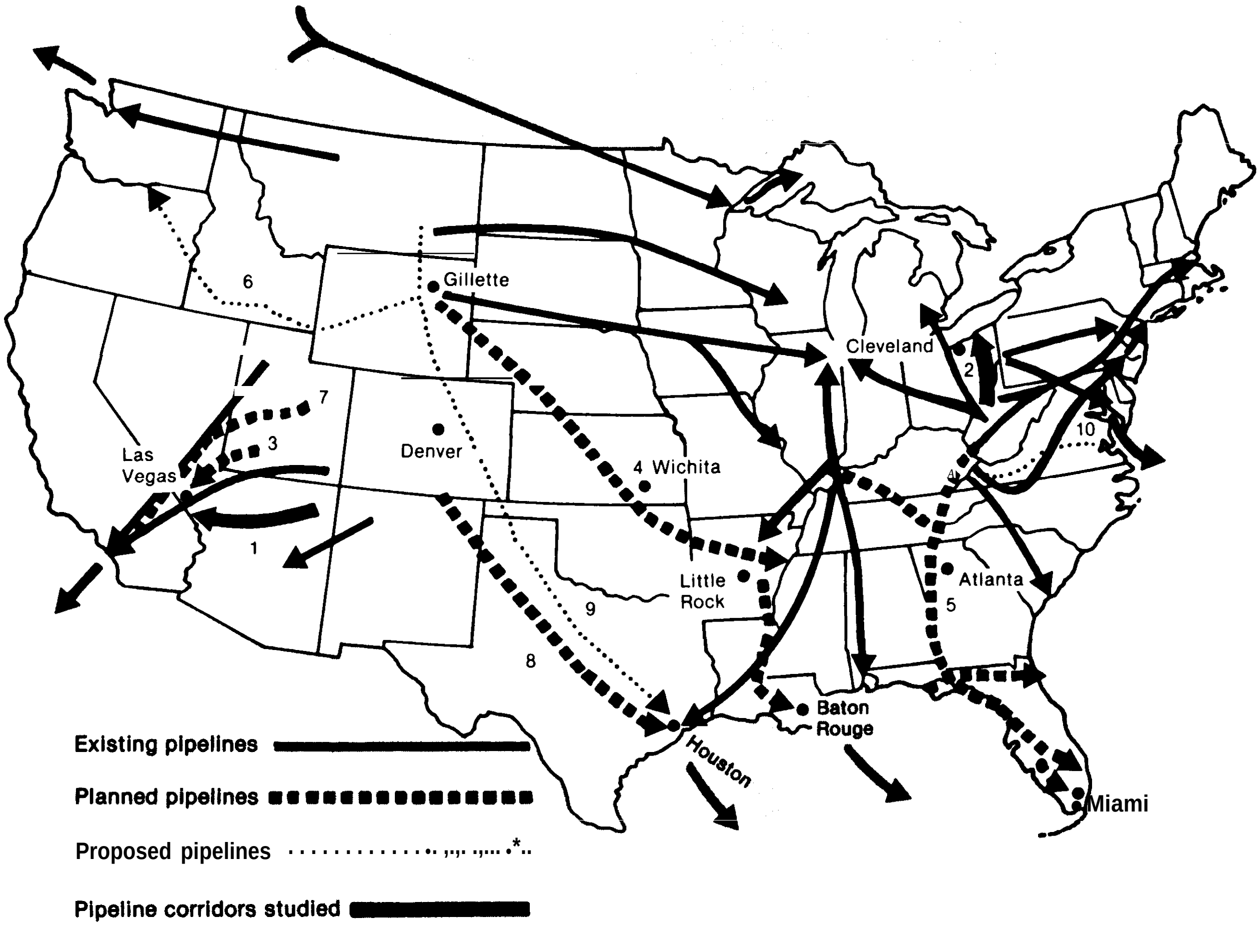
> ,.. the introduction of coal slurry pipelines is not likely to affect materially the rate of coal resource development and use on a national scale. It may, however, affect the regional pattern of coal mining and distribution in such a way as to expand the use of

[46] ICF, The *Potential* Energy and Economic *Impacts of Coal Slurry* Pipelines, Draft *Final* Report (Washington, D. C.: ICF, December 1979), pp. 1-2.

[47] OTA, *Coal Slurry* pipelines, Summary (Washington, D. C.: U.S. Government Printing Office, September 1980), p. 8. This summary updates an earlier report, A Technology Assessment *of Coal* Slurry PipeJines (Washington, D. C.: U.S. Government Printing Office, March 1978). The array of legal, economic and environment issues involved in the slurry pipeline debate are discussed in full in OTA's 1978 Assessment and in the 1980 update.

[48] An extensive discussion of these tradeoffs is found in OTA's assessment, *Coal Slurry* Pipelines, chs. V and VI.

Figure 39.—Coal Slurry Pipeline Systems



Pipeline[a]	Principal company affiliation	Origin	Destination	Distance (miles)	Capacity (million tons/year)	Capacity potential to export (million tons/year)
A. Existing						
1. Black Mesa pipeline (to present)	Consolidation Coal Co.	Kayenta, Arizona	Southern Nevada	273	4.8	None
2. Ohio pipeline (1957-1963)		Cadiz, Ohio	Cleveland, Ohio	108	1.3	None
B. Planned or proposed						
3. Allen-Warner Valley Energy System (Alton pipeline) (1983-19843)	Nevada Power Co.	Utah/Arizona	Nevada	183-256	11.8	None
4. Energy Transportation Systems Incorporated (ETSI pipeline) (1983)		Powder River basin/Wyoming	Oklahoma/Louisiana Arkansas	1,378	25	**0.5**
5. Continental Resources (Florida pipeline) (1985-1986)	Florida Power Co.	Southern Illinois/West Virginia/Kentucky	Georgia/Florida	600 – 1,500	**40-50**	10
6. Northwest Integrated Coal Energy System (Gulf Interstate Snake River pipeline)		Powder River basin Wyoming	Oregon	1,100	25	0.5
7. Pacific Bulk Commodity Transportation System pipeline	Boeing Corp.	Emery, Utah	Oxnard, Cal if.	645	10	10
8. San Marco pipeline (1983)		Colorado/ New Mexico	Houston, Tex.	900- 1,100	15	None
9. Texas Eastern (Wytex pipeline) (1985)		Gillette, Wyo.	Houston, Tex.	1,260	25	0.5
10. Vepco pipeline	Virginia Electric Power Co.	Southwest Virginia	Tidewater, Va.	300	5-1o	None
Total[b]					161-176	20-35

[a] Target **operating** date, when available, In parenthesis.

[b] Excluded the closed Ohio Pipeline

SOURCE: Data furnished by Coal Slurry Transport Association, May 1980, and National Coal Association, 1978 western coal to greater distances from its area of origin.[49]

The degree to to which pipelines affect rail traffic depends on whether pipeline operators win passage of eminent-domain legislation and on the level of rail rates. As rail rates increase, the economic attractiveness of pipelines increases as well. If Federal pipeline legislation is enacted, pipeline operators will enjoy a regulatory advantage over railroads. The pipeline industry argues that the absence of Federal eminent-domain legislation is a significant constraint on pipeline construction. Such legislation would make construction easier and accelerate the construction of pipelines, but it does not appear to be essential to the construction of any individual pipeline.

The principal environmental constraint on pipeline construction has to do with water. For any particular pipeline, water availability may not be a problem. However, when water demand for all possible new energy facilities in a western basin, including mine-mouth plants, synthetic-fuel facilities, and pipelines are totaled, water availability can become an important constraint on pipeline construction. Moreover, Montana and Colorado prohibit export of local water, and Wyoming requires legislative approval before export can occur. Assuming that the legal and environmental water issues are resolved, the only likely constraint on pipeline development arising from the operation of the lines would be citizen objection to spillage from breaks. Federal and State environmental regulations may be violated in such accidents.

[49])TA, Coal Slurry pipelines, Summary, p. 9, September 1980.

Port Facilities: Capacity and Constraints

Very little Western coal is being exported to Asia. If Asian exports are to increase, improved port facilities are required. Domestic port facilities at Los Angeles, Long Beach, and Stockton, Calif., are currently capable of loading only several million tons per year. plans for expansion of these port facilities have been announced. The volume of coal that could be transferred through these ports may be constrained by area rail system capacity. The port at Vancouver, British Columbia, now has a capacity of 15 million tons per year, and could handle some Western coal. Seattle plans to expand its coal export facilities to 40 million tons per year by 1990, if export sales warrant such an investment. Other Western ports may also invest in expansion if the coal export market grows.[50]

[50] see Office of Technology Assessment, Coal Exports and Port Development, OTA-TM-O-8 (Washington, D. C.: U.S. Government Printing Office, April 1981).

Comments on Regional and State Transportation Factors

Powder River Basin

The Powder River basin is likely to supply an increasing percentage of Federal coal. In 1979, the Montana-Wyoming Powder River basin produced about 80 million tons of coal; 72 million tons of this came from mines containing Federal leases. About 160 million tons are contracted for 1990 from Federal mines alone (see ch. 7). Almost all of this coal will be consumed by utilities. Unless coal slurry pipelines are built, more than 90 percent of

Federal coal will be hauled by rail, If the three pipeline projects mentioned in figure 39 are completed by 1990, they would transport 75 million tons per year.

Texas and Iowa will be two principal consumers of Federal coal from the Powder River basin in 1990. Other States that have contracted for large amounts of Powder River basin coal include Montana, Minnesota, Colorado, Wisconsin, Michigan, Indiana, Ohio, Oklahoma, Wyoming, and Kansas.

A rough idea of the rail traffic these contracted tonnages represent can be calculated on the assumption that it requires one set of 100 cars making 100 trips to transport 1 million tons. Powder River basin contracted output from mines including Federal leases will require 16,000 unit-train trips. Traffic past any given point is doubled to take into account the returning trains.

Assuming that the average coal car makes 46 trips annually (7-day cycle time plus 45 days maintenance), this tonnage would require 348 unit trains with at least 34,800 hopper cars. The time that a particular community is disturbed by train traffic depends on the amount of traffic, time of day, and train speed. A town through which 25 loaded and 25 return trains pass daily will be disturbed from 1 to 5 hours depending on train speed. * It should be recalled that other traffic (some non-Federal coal but principally noncoal commodities) will also be using this rail system, thereby increasing the traffic.

BN, which serves the powder River basin, will have to expand its capacity if it is to handle 1990 coal traffic. Although most Federal leases lie within 15 miles of existing rail lines, roadway limits down the line from the point of origin may present bottlenecks in the future.[51] Obtaining sufficient rolling stock is less of a problem than upgrading and constructing adequate roadway. As was noted previously, likely bottlenecks have been pinpointed on rail lines running east from the basin through Nebraska and Iowa to Missouri and south through Colorado and Texas. Traffic through the southerly corridor could be eased by operation of two proposed 25-million-ton-per-year pipelines: the Texas Eastern (Wytex) line from Gillette to Houston; and the ETSI line from the basin through Oklahoma, Louisiana, and Arkansas. The Wyoming State Legislature passed a bill in 1974 specifically authorizing export of water through the ETSI line. This line has obtained the necessary rights-of-way, air-quality permits, and EIS clearance. It could become operational in the mid-1980's. Unresolved legislative and water-resource issues have impeded rapid development of slurry pipelines originating in the basin. The lack of eminent-domain legislation and a recent decision by the Governor of Wyoming that pipelines should be developed only if they use nonwater technologies are significant constraints.

Managing the transportation of 1990 coal production from the basin will require cooperation among Western railroads. The BN and Chicago Northwestern (CNW) recently constructed a line from Gillette to Douglas, Wyo., which greatly improves the basin's coal-export capacity. But CNW's coal haulage also depends on use of UP track that runs east-west through southern Wyoming. BN has refused to share a connecting line with CNW, which prevents that carrier from hauling coal east on the UP track. CNW has proposed to build its own connecting track, but has encountered strong opposition from local residents.[52] CNW, however, expresses con-

*This would represent an annual tonnage of 91.25 million tons. Towns on the BN's track in Wyoming, Colorado, Nebraska, and Iowa can expect this level of traffic. Towns south of Gillette may have more trains passing through on a daily basis, depending on Basin output.

[51] NETS, p, 33 ff. and fig. 3-2. NETS identified 67 congested rail links in the coal transportation network nationally. About three dozen of these bottlenecks were identified in the West along transport routes for Powder River basin coal. (NETS, fig. 3-2). However, NETS used 1975 data that did not take into account post-l975 rail investment beyond what was underway in that year. BN and other major Western rail haulers have significantly upgraded their mainlines since 1975 to meet heavier current traffic. The BN, for example, originated less than 19 million tons of coal in 197o compared with 80 million tons in 1980 and 100 million tons forecast for 1981, according to BN president Richard Bressler,

[52] Powder River Basin Resource Council, "WYOBRASKA Keeps Up the Pressure," Powder River Breaks, September 1981.

fidence that it will be able to realize its plans to haul approximately 45 million tons per year from the Powder River basin in 1990.[53]

Other Wyoming Regions

Wyoming will also produce coal from the Hanna, Rock Springs, and Kemmerer fields in southern Wyoming, At the present time, all of the coal produced in this region comes from Federal mines—23 million tons of production in 1979, Coal production from this region will increase during the 1980's. The UP serves these coalfields. The UP seems able to haul expected tonnage without difficulty from this area. Because there are more communities in southern Wyoming than in and around the Powder River basin and because UP carries other commodities, some communities may be adversely affected despite the comparatively modest coal traffic increases.

Fort Union Region of North Dakota and Montana

It is not cost effective to transport lignite far from the mining site. Lignite has the lowest energy value and highest moisture content of the domestically mined coals, These factors force utilities to burn lignite close to the mine site. All of the powerplants currently under construction or planned in North Dakota will burn coal at the mine site.

Only one operating powerplant–the Big Stone facility—consumed more than 1 million tons of lignite annually from mines situated more than 100 railroad miles away, This South Dakota plant designed and built special covered hopper cars for hauling lignite from Knife River Coal Co. 's Gascoyne Mine 350 miles away. The Milwaukee Road (Chicago, Milwaukee, St. Paul, and Pacific Railroad) owns and operates this 350-mile track over which two unit-trains pass daily, The Milwaukee's bankruptcy may result in cutbacks in service. The Milwaukee Road Trustee requested a new freight rate, which would increase the transport costs of lignite by 65 percent. The partners at the Big Stone plant rejected this because the trustee was unwilling to provide guarantees that any portion of the new rate would be used to maintain the roadbed between the mine and the powerplants. North and South Dakota have been spending Railroad Recovery Act funds to maintain this track, which is considered to be in worse shape than any other stretch in the Milwaukee system. Milwaukee applied to its bankruptcy court and to the ICC in May 1981 for permission to abandon this tract. The ICC will make a recommendation to the court on September 15, at which time a final decision will be made.

While Gascoyne production has not been constrained by transportation factors up to now, Knife River's New Liepzig project has been delayed indefinitely by BN's unwillingness to invest $20 million to $24 million to upgrade the track that would carry about 2 million tons per year to a powerplant in Mandan, N. Dak. Knife River wants to prorate the upgrading costs between itself and BN (which owns extensive mineral rights along this line), but BN contends that Knife River should finance all the costs. BN stands to gain little from this investment because the expected traffic volume is so small. On the other hand, Knife River has no other way to move coal from this site.

Colorado

Transportation factors play a major role in determining the market potential of Colorado coals. Transportation costs are an important variable because Colorado coal from underground mines must compete with cheaper surface-mined coal from Wyoming and New Mexico. Moreover, Colorado coal must be shipped over the Rocky Mountains to reach Midwest and South-Central markets, Mine operators in the Green River region, the State's largest producing area, complain that rapidly escalating rail rates are destroying

[53] Remarks of' Douglas A. c hristensen, Vice president for Marketing of C&NW Transportation Co., at the Coal Outlook Conference Charting the Future of Western Coal, June 8-9, 1981.

their competitiveness. The Denver & Rio Grande Western (D&RGW), which serves western Colorado, argues that its rates are fair considering the high costs of upkeep under difficult conditions, such as the Mofatt Tunnel that leads to Denver and easterly markets. Higher rates also reflect the cost of new sidings and the installation of CTCS, the railroad says. The D& RGW's continued ability to move projected expanded coal output from western Colorado to the front range is open to question despite the railroad's assurances. The Green River-Ham's Fork environmental impact statement (EIS) found that with 20 million tons of new annual production from new lease sales, about 75 percent of D& RGW's capacity would be used. One alternative that has been suggested by local governments and mine operators to expand coal transportation capacity in northwest Colorado is construction of an extension of the UP line from Rawlins, Wyo., to Craig, Colo. No such extension of the UP into D& RGW's service area has actually been proposed.

Other rail capacity questions are apparent. Until the Tongue Mesa Field and the San Juan coalfield around Durango are served by rail, it is unlikely that significant development will occur there. The Federal leases in the Coalmont Field of the North Park region probably cannot be developed until the abandoned UP line from Walden to Hebron is substantially upgraded. This line has sharp turning radii and steep grades. These improvements will probably not be made unless enough coal can be shipped from the area under long-term contracts to offset the costs.

Several coal mines in the Green River region truck their coal to railheads at distances ranging from 2 to 30 miles. This has created additional expense for the mine operators and road damage to certain highways. Conveyors and rail spurs are being evaluated by some companies to reduce truck use. One coal slurry line originating in Colorado has been discussed—the San Marco line from Walsenburg to Houston, Tex. However, the Colorado legislature has barred exportation of the State's water. This policy coupled with other demands on local water resources makes this pipeline an unlikely prospect without Federal enabling legislation or legal resolution of water-rights issues,

New Mexico

The OTA New Mexico task force estimated that total coal production in the State could increase from 14,6 million tons in 1979 to as much as 72 million tons by 1990 under favorable conditions. Of this number, about 55 million tons would be exported, mostly to utilities in California and Texas. Although New Mexico has traditionally exported more than half its in-State produced electricity to out-of-State customers, the emphasis over the next decade is likely to be shipping coal by rail.

The construction of the Star Lake Railroad in west-central New Mexico is a major factor in this increased production. This line would connect the Star Lake-Bisti area of the San Juan basin, which contains one of the largest untapped strippable coal deposits in the Western United States, with the Santa Fe main line at Prewitt, N. Mex. Five large undeveloped leases and 28 outstanding preference right lease applications (PRLAs) are found in this area, as well as large reserves of fee, State, and Indian coal. The 114-mile Star Lake line could carry almost 17 million tons per year by 1990, and, if fully developed, this area would be able to mine as much as 75 million tons per year. Production of about 8 million tons of coal from Federal leases in 1990 hinges on construction of this railroad, as does an additional 18 million tons from mines on land covered by PRLAs. Construction of the Star Lake Railroad has been delayed because of difficulties in obtaining all the necessary rights-of-way. However, progress has been made; a right-of-way over public lands has been approved. Several questions involving rights-of-way over public lands and individual Indian allotment lands remain to be resolved. About three miles of tribal trust lands and 25 miles of allotment lands are involved. It is expected that all necessary rights-of-way will be obtained. Construction would begin within a few years after the right-of-way issues are settled and would be completed within 2 years, according the the Santa Fe's estimates.

Other transportation issues are relevant to other coal development in New Mexico. Mine construction on several Federal lease blocks will require upgrading of local roads. A 230-kV transmission line would have to be constructed to link the proposed New Mexico Generating Station near Bisti with the existing electrical grid 209 miles to the southeast. Another proposed rail connection from mines on the Navajo reservation to the east-west trunk line at Gallup is also under consideration. The carrier—the Santa Fe—has acquired right of way to 22 miles and the remainder is under discussion. This line would carry between 4 million and 25 million tons per year if completed.

Utah

Most Federal leases in central Utah are located near existing road and rail transportation systems which appear to be adequate to handle future production. In this area, coal would be moved by truck, rail, or conveyor to the powerplant or railhead. Improvements and repairs to existing systems are underway. Some mines currently have to truck coal 60 miles to rail connections, but this does not seem to have been a constraining factor in mine development, This truck haul would be reduced when the planned Castle Valley Railroad extension is constructed.

Southern Utah, on the other hand, does not have a well-developed transportation system serving potential coal mining areas. Two coal slurry pipelines 180 miles long would connect the Alton Mine to the proposed Allen Warner Valley Power Project. The slurry plan conflicts with Utah law restricting transfer of water out of State, The Kaiparowits Plateau Field is not currently served by rail or major roads. Coal development there depends on construction of a rail or slurry line to move coal to market, A minimum of 30 million tons of annual production is required to offset the cost of building a rail line from the plateau. Such a rail line has been under study, but no date has been proposed for its construction.

Oklahoma

Oklahoma's coal production, currently at about 5 million tons per year, is not projected to increase substantially over the next decade. Utilities in Oklahoma buy coal from other States, principally Wyoming, because of its low-sulfur content. Oklahoma's high-sulfur steam coal is exported to generating plants in other States that have less restrictive air pollution requirements. Oklahoma's metallurgical coal markets depend on demand rather than supply-side or transportation factors. Much of Oklahoma's current production is trucked to rail and barge centers throughout the region. County roads and bridges adjacent to Federal coal properties are typically in poor condition and some cannot accommodate heavy commercial traffic. Coal industry spokesmen have expressed a willingness to build new roads or repair existing ones. Rail lines to major rail and barge connections are ill-suited to transport large quantities of coal efficiently, but should prove sufficient to handle expected output with some upgrading. One Oklahoma coal operator has stated that the "only way that is economically feasible (to export Oklahoma coal) is by barge; the rail rate is simply too high."[54]

[54] OTA correspondence with J. F. Porter, III, Vice-president of Garland Coal & Mining Co., February 1981.

CHAPTER 9

Federal Coal Lease Management

Contents

List of Tables

List of Figures

CHAPTER 9

Federal Coal Lease Management

Legal Framework and Policy

The Federal Government has both proprietary and sovereign responsibilities for Federal lands. A proprietary responsibility to manage the publicly owned lands and natural resources to meet the Nation's needs for energy, minerals, timber, agricultural production, and recreation while ensuring a fair return on public resources; and a sovereign responsibility to encourage and regulate commerce while at the same time protecting and conserving the natural heritage. The statutes and policies providing the framework of these Federal responsibilities for the management of Federal coal resources are reviewed below.

Historical Development of Federal Land Policies

Lands owned by the Federal Government are either: 1) public domain lands, acquired by cession, treaty or purchase from other sovereign nations; or 2) acquired lands purchased by the Government from private owners after the lands were made part of the Union. By 1867, approximately 1.8 billion acres of land had been added to the public domain through a series of purchases and treaties. Most of these public domain lands were west of the Mississippi River, Figure 40 shows the distribution of federally owned lands in the conterminous 48 States in 1976.

Federal land policy from the time the Nation gained independence through the end of the 19th century had five objectives: 1) to produce revenue for the Government; 2) to facilitate settlement and growth in the various regions; 3) to reward war veterans; 4) to promote education and charitable institutions; and 5) to encourage the construction of internal improvements, e.g., railroads, roads and canals to promote transportation and commerce.

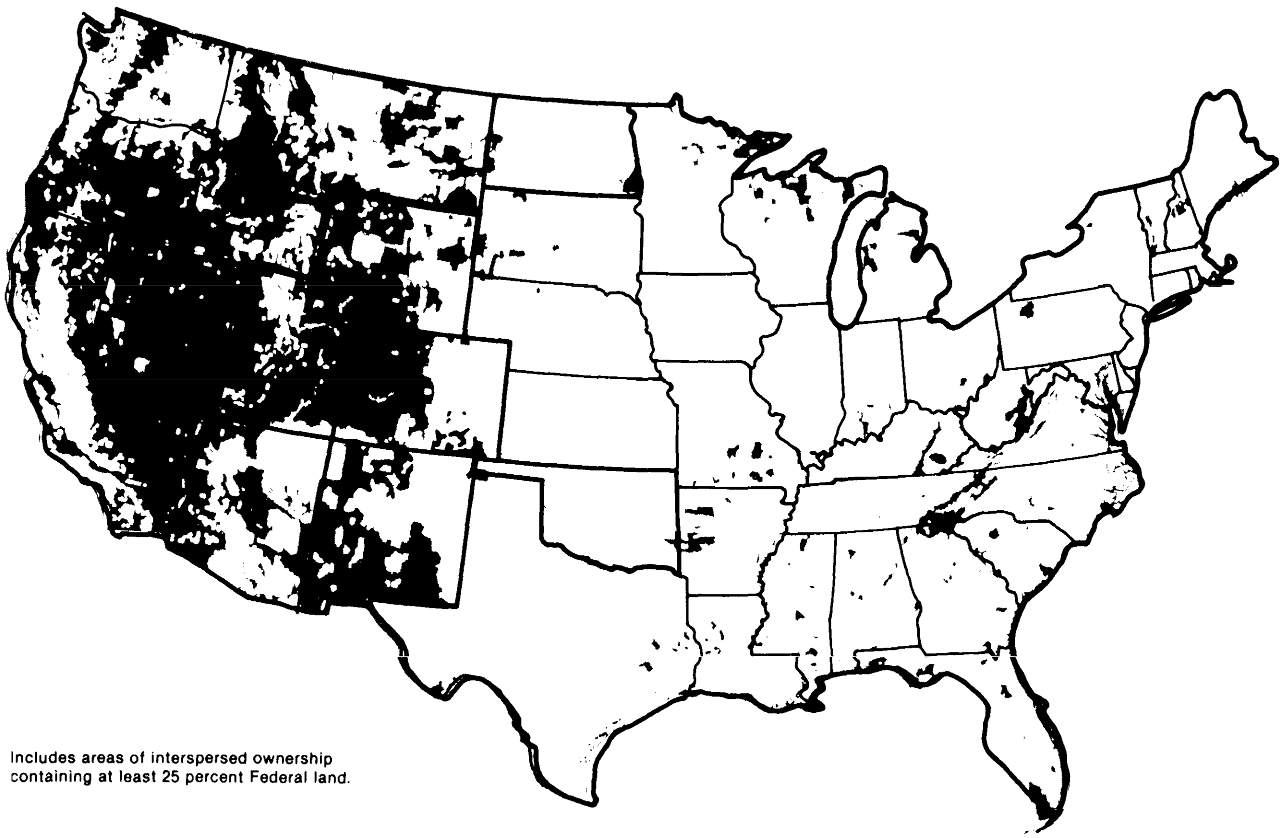
Federal land policy has historically been aimed at disposing of Federal land to private interests through a number of devices including sales, military warrants, preemption, homesteading, and direct grants to States and railroad companies. Through each of these mechanisms, vast areas of the public domain were transferred to private ownership. Those areas that were less favorable for economic use during the period of disposal of public lands were largely retained by the Federal Government, and today constitute the major part of the lands managed by the Bureau of Land Management (BLM).

The intermingled landownership patterns that are the legacy of earlier public lands policies in the West have a direct and significant impact on the management of Western Federal coal lands today. Two aspects, in particular, created land ownership problems for the development of Federal coal lands: 1) checkerboard land grants made to the transcontinental railroads: and 2) severed estates, the separation of surface ownership from subsurface mineral ownership.

Railroad Land Grants.—Over 94 million acres of Federal lands were given to the railroads directly as railroad land grants. An additional 37 million acres were granted to the States for their use to encourage rail development within their boundaries. Figure 41 shows the location of these railroad grants.

Railroad grants were awarded on odd-numbered sections on either side of the proposed right-of-way, with even-numbered sections retained in public ownership. This resulted in what is called a "checkerboard" ownership pattern and still influences the development of Western coal, particularly in areas of North Dakota, Montana, Wyoming, and in New Mexico where the transcontinental railroads were granted lands under the Pacific Railroad Act. Many railroads sold

Figure 40.–Principal Federal Landholdings in the Conterminous United States (1976)



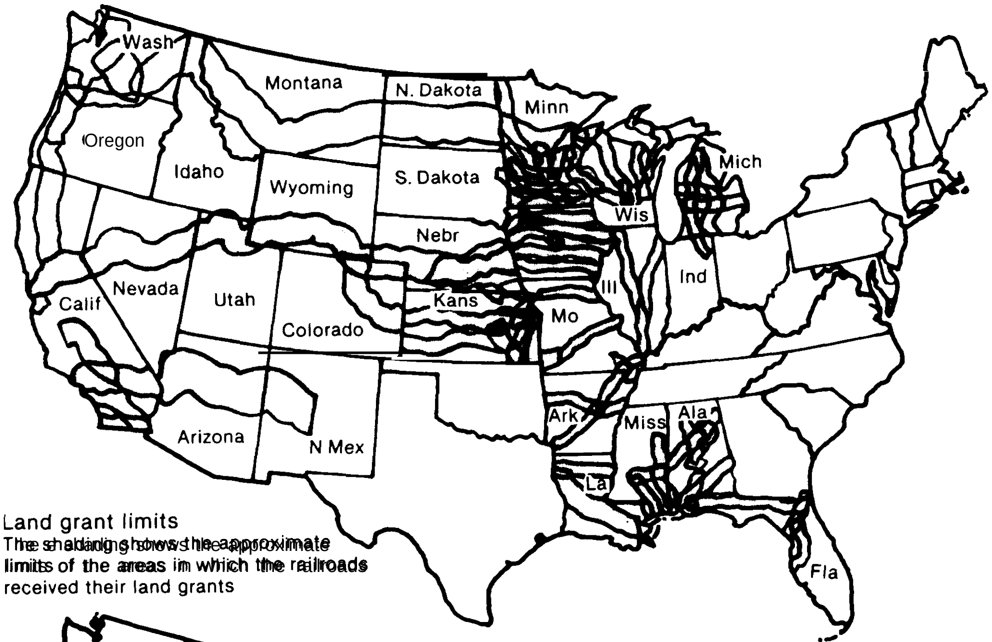
SOURCE: U.S. Geological Survey, Special Maps Branch, 1977

their grants both to encourage settlers and to generate revenues to finance construction. A substantial amount of railroad land grants underlain with valuable coal deposits remains in railroad ownership today.

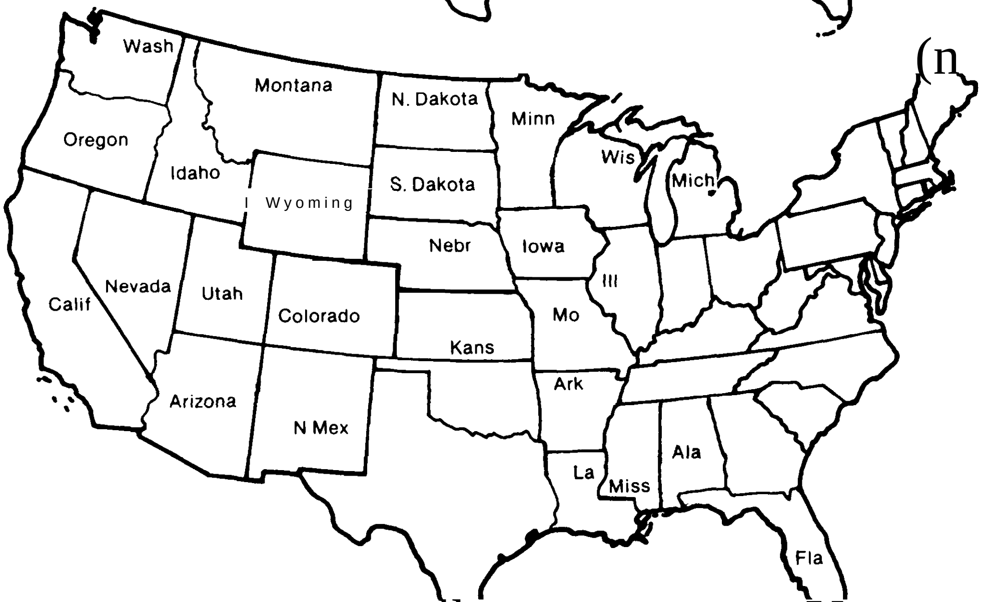
Surface Ownership and Mineral Interests.— The early 20th century policy of retaining Federal ownership of subsurface mineral rights while granting surface ownership to private parties subsequently created problems for both parties of interest.' The values to the surface owner are in use of the land for grazing, agriculture, recreation, timber, or other surface activities. Mining, on the other hand, frequently involves surface disturbance and can interfere with the surface owner's use of the land. In large strip mines, the surface landowner could be displaced from the property for as much as 30 to 40 years over the life of the mine. Moreover, even after mining, reclamation may not fully restore all of the land's previous characteristics. Under law, mining is considered the dominant land use; the surface owner is compensated for any damages to or loss of buildings and other improvements on the land disturbed by mining. Large quantities of Federal coal may lie below lands whose surface is privately owned. Achieving an equitable balance between the interests of the surface owner and the interest of the public in making coal resources available for development is often a contentious and difficult administrative problem in the Western coal regions. Section 714 of the Surface Mining Control and

NOTE: Footnotes for this chapter are found on pp. 265-269.

Figure 41.— Federal Land Grants for Railroads



Land grant limits
The shading shows the approximate limits of the areas in which the railroads received their land grants



Acreage granted
The shaded areas are in proportion to the acreage received by the railroads. They do no show the exact location of the granted lands, which in general formed a checkerboard pattern.

SOURCE. Bureau of Land Management.

Reclamation Act of 1977 (SMCRA)[2] bars the leasing of Federal coal under certain privately held lands unless the surface owner consents to the lease. Section 714 does not apply to existing leases and preference right lease applications (PRLAs)[2] which cover over 200,000 acres of privately owned surface land. Table 73 shows the surface ownership of Federal coal leases in Western coal States.

Reforms Under the Mineral Leasing Act of 1920

Before 1920, Federal coal lands were sold under the authority of the 1873 Coal Lands Act.[3] Sales were limited to 160 acres for individuals and an association could purchase up to 320 acres. The enactment of the Mineral Leasing Act converted the policy of sale of coal land to a policy of leasing rights to explore, develop, and remove coal and other fuel and fertilizer minerals.'

Under the 1920 Act, the Secretary of the Interior could issue prospecting permits that entitled the permittee to the exclusive right to prospect for coal in areas with no known coal deposits. The permits were converted into preference right leases if the permitters could demonstrate the discovery of coal in commercial quantities.

Under the provisions of the 1920 Act, Federal lands containing known commercial coal deposits were divided into leasing tracts and leases were awarded competitively to the highest bidder for a cash bonus,

The Mineral Leasing Act provided for leases to be issued for an indeterminate period so long as the lessee could demonstrate diligent development and continuous operation of the lease. Royalties were originally set at not less than 5 cents/ton of coal and annual rentals could not be below 25 cents, 50 cents, and $1.00/acre for the first, second through fifth, and sixth through 20th years, respectively. The leases were subject to readjustment of terms and rentals and royalties at the end of each 20-year period after issuance.

1971 Moratorium on Coal Leasing

Between 1920 and 1970, Federal coal was virtually leased on demand, i.e., wherever and whenever anyone requested a lease sale or permit, In 1970, a study conducted by BLM found that although the amount of leased Federal coal had increased dramatically in the previous decade, coal production had significantly declined in comparison to the amount of coal under lease. ' This study ultimately led

Table 73.—Surface Acreage of Leases and PRLAs by State and by Surface Ownership: Sept. 30, 1980

State	Number of leases	Total acres	Federal lands BLM	FS	Other	Native American	State	Private
Colorado	127	126,875	45,773	22,589	0	0	0	58,498
Montana	22	37,445	1,225	80	0	0	0	36,141
New Mexico	29	44,761	20,047	0	0	9,148	7,086	8,478
North Dakota	18	17,504	0	0	0	0	0	17,504
Utah	204	279,654	187,993	50,102	0	0	28,108	13,450
Wyoming	98	217,835	93,854	4,440	1,324	0	1,840	116,355
Total	498	724,074	348,892	77,211	1,324	9,148	37,034	250,426

State	Number of PRLAs	Total acres	Federal lands BLM	FS	Other	Native American	State	Private
Colorado	37	82,911	23,279	1,203	0	0	0	58,306
Montana	4	14,673	9,917	0	1	0	0	4,756
New Mexico	26	75,509	55,229	0	2	6,101	0	14,180
Utah	21	68,586	54,076	13,609	2	0	40	861
Wyoming	82	138,275	34,325	8,927	1	1,080	923	93,239
Total	170	379,954	176,826	23,739	6	7,181	963	171,342

NOTE: Details may not add to total due to rounding.

SOURCE. U.S. Department of the Interior, Bureau of Land Management, Off Ice of Coal Management, *Automated Coal Lease Data System,* Sept. 30, 1980.

to an informal moratorium on further leasing of Federal coal in 1971. In 1973 the moratorium was formalized by secretarial order but modifications provided for new leases to maintain existing mines or to supply near-term production to satisfy existing market demands.[6] The Department of the Interior (DOI) immediately began developing an improved, long-term coal leasing program.

Meanwhile, congressional hearings on coal leasing (1972-74) focused on whether Federal coal leases were being held for speculation and whether enforcement of lease conditions of diligent development and continued operation were ineffectual. ’ As a result of the hearings, legislation amending the 1920 Mineral Leasing Act eventually passed over President Ford’s veto in August 1976.[8] The amendments included provisions limiting the holding of Federal leases without production.

Energy Minerals Activity Recommendation System (EMARS)

While Congress was considering changes to the Mineral Leasing Act in 1975, DOI announced a new coal leasing program, EMARS, which involved the industry more directly in the tract selection process.[9] Instead of DOI identifying the areas eligible for leasing or offering leases in response to specific sale requests, as was the procedure under the 1920 Mineral Leasing Act, the EMARS procedure was an integrated planning process for lease sales that involved annual nominations for coal leasing areas by the industry and the public, The program was opposed by the western Governors and agricultural interests, and environmental groups. In 1975, the Natural Resources Defense Council (NRDC) sued DOI for insufficiently describing the EMARS program and its potential consequences in the environmental impact statement (EIS).

Two years later, the District Court for the District of Columbia, in NRDC v. Hughes, found the EMARS programmatic EIS inadequate under the National Environmental Policy Act of 1969 (NEPA). The EIS failed to consider the impacts of a no-action alternative of not establishing a new leasing program,[10] and the proposed leasing system described in the final EIS differed substantially from the system described in the draft that was circulated for public comment. The court enjoined DOI from implementing the EMARS program and from any new leasing, except where the proposed lease was necessary to maintain an existing mining operation or necessary to provide reserves to meet existing contracts, until DOI fully complied with the requirements of NEPA,[11]

The case was settled on June 14, 1978 under an agreement permitting additional leasing and the processing of 20 PRLAs while DOI developed a revised coal program and EIS.[12] By 1980, leasing under the 1978 settlement had resulted in 29 new leases covering 20,822 acres containing 212 million tons of recoverable reserves.

The task of preparing an adequate EIS and formulating changes to the system of leasing Federal coal reserves fell to the new Carter administration and the moratorium continued. By April 1979, the EIS process was completed.[13] In July 1979, under the Federal Coal Leasing Amendments Act of 1976 (FCLAA),[14] the Federal Land Policy and Management Act of 1976 (FLPMA),[15] and the settlement of NRDC v, Hughes, DOI promulgated regulations implementing a new Federal coal leasing program.[16] The first lease sales under the new program were held in January 1981.

Federal Coal Leasing Amendments Act of 1976

FCLAA contains several provisions aimed at what were characterized in the hearings as problems of speculation and nonproduction. The noncompetitive preference right leasing system was repealed on the basis that it did not grant the public a “fair return.” All new leases are to be issued competitively and no bid can be accepted for less than the fair market value of the lease. The amendments also provide for: 1) the consolidation of leases into “logical mining units” (LMUS) to assure maximum economic recovery (MER): 2) dili-

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gent development and continuous operation on each lease, and 3) preparation of a comprehensive land use plan before coal lease sales. See table 74 summarizing the major provisions of FCLAA.

Federal Land Policy and Management Act

FLPMA is the comprehensive "organic" act for BLM. Before passage of FLPMA, BLM operated on a series of authorizing acts, reorganization plans, and secretarial orders which gave little guidance to the overall management of the public lands. Each act addressed a separate problem, but failed to set goals and objectives for BLM as it attempted to balance the use and development of Western lands under its jurisdiction.

In FLPMA, Congress directed BLM to manage the public lands (including Federal mineral interests under private surface) within a framework of land use plannng. Among the principles set out in the legislation are the guidance to manage the lands for "multiple use" and "sustained yield" and to assure that the fair market value is received for the sale or use of public resources.[17] BLM was directed to protect areas of critical environmental concern, to consider present as well as future uses of public lands, to provide for compliance with applicable Federal and State pollution control laws, and to coordinate planning activities with those of other Federal, State, and local agencies. Section 603 of FLPMA also directs DOI to inventory and study BLM roadless lands for potential congressional designation as wilderness areas. The general requirements for management of public lands under FLPMA also govern activities on Federal mineral leases.

Table 74.—Federal Coal Leasing Amendments Act of 1976: Summary of Major Provisions

Sec. 2	All leases are to be sold by competitive bid with 50 percent of lands offered in any year to be awarded under a system of deferred bonus bidding and a "reasonable number" of tracts are to be reserved for leasing by public bodies. No bid may be accepted for less than the fair market value of the tract offered. Minimum lease size is changed from 40 acres to such size that "will permit the mining of all coal which can be economically extracted".
Sec. 3	The Secretary shall not issue a lease to a lessee who has held a lease for ten years (after passage of FCLAA) without producing coal in commercial quantities. All lands to be leased must be included in a comprehensive land use plan. DOI must consult with State and local governments and provide opportunities for public hearings if requested in preparing land use plan. Secretary must consider the social, economic, and other impacts on the communities affected and provide an opportunity for a public hearing before a lease is issued. DOI must obtain consent of Federal surface management agencies outside DOI before leasing lands under their jurisdiction. DOI must consult with State Governor before leasing National Forest lands. Advance notice must be given of competitive lease sales including publication in local newspapers. No mine plan for leased lands may be approved unless it provides for maximum economic recovery of coal within the tract. All coal leases are to contain provisions requiring compliance with the Federal Water Pollution Control Act and the Clean Air Act.
Sec. 4	Repeals, subject to valid existing rights, provision allowing noncompetitive leasing through issuance of prospecting permits and preference right leases. Establishes a system of nonexclusive exploration licenses. Licensees must furnish all data acquired to Secretary, however, information is kept confidential until after the area is leased.
Sec. 5	Repeals, subject to valid existing rights, provision for collective contracts for exploration, development and operations. Substitutes concept of Logical Mining Unit (LMU). Allows consolidation of Federal leases and non-Federal lands into single LMU if maximum economic recovery is served. Lease terms in LMU may be modified so that requirements imposed on leases are consistent. Pre-FCLAA leases may be included in LMU with consent of lessee. Aggregate production from LMU may be used to meet diligence and continued operation requirements. Mining plan approved for LMU must provide for depletion of LMU reserves in 40 years. LMU may not be larger than 25,000 acres.
Sec. 6	Amends section 7 of MLA to provide that leases are for an initial period of 20 years with readjustments at the end of the initial term and every 10 years thereafter. Any post-FCLAA lease not producing in commercial quantities at the end of 10 years shall be terminated. Minimum royalty for coal mined by surface methods shall be 12.5 percent; with a lesser royalty as determined by the Secretary for coal recovered by underground methods. Allows payment of advance royalties (determined by a fixed reserve to

Table 74.—Federal Coal Leasing Amendments Act of 1976: Summary of Major Provisions—Continued

	production ratio) in lieu of continued operation, however, advance royalties may not be accepted for more than 10 years during the period of any lease. Requires submittal of a mining and reclamation plan within 3 years after the lease is issued; Federal surface management agency must consent to DO I approval of mine plan.
Sec. 7	Establishes program for comprehensive coal exploration program for Federal lands to support land use planning and leasing operations. Information from coal exploration program, except for certain proprietary data, is to be made public.
Sec. 8	Requires annual reports to Congress by the Secretary of the Interior on the management of Federal coal leases and by the Attorney General on competition in the coal industry, including an analysis of whether the antitrust laws are effective in preserving or promoting competition in the coal or energy industry.
Sec. 9	Amends the revenue distribution provisions of section 35 of the MLA by reducing the amount paid to the Reclamation Fund from 52½ percent to 40 percent (and raising the amount paid to the States by 12½ percent.) Directs that States may spend their share of the revenues as each State Legislature provides giving priority to the needs of communities impacted by Federal mineral leasing.
Sec. 10	Requires Office of Technology Assessment study of Federal coal leases.
Sec. 11	Amends section 27 of the MLA to provide that no entity may control more than 46,080 acres of coal leases and permits in any one State nor more than a total of 100,000 acres in the United States. Lessees controlling more than 100,000 acres on passage of FCLAA may continue to own their leases, but may not acquire more leases until the total acreage controlled is less than 100,000 acres. The definition of a lessee entity is broadened to include a person, association, or corporation, or any subsidiary, affiliate or persons controlled by or under common control with such person, association or corporation.
Sec. 12	Authorizes leases to governmental entities of acquired lands set aside for military or naval purposes.
Sec. 13	Repeals, subject to valid existing rights, authority to lease an additional 2,560 acres of coal lands to a lessee who has exhausted the reserves in the original lease. Substitutes new provision allowing noncompetitive leasing of up to 160 acres as a modification to a contiguous existing lease.
Sec. 14	Amends section 39 of MLA to limit authority of Secretary to waive suspend or reduce advance royalties.
Sec. 15	Requires Secretary to consult with Attorney General before drafting rules and regulations or before issuing, renewing or readjusting leases as to whether the proposed action would create a situation inconsistent with the antitrust laws.

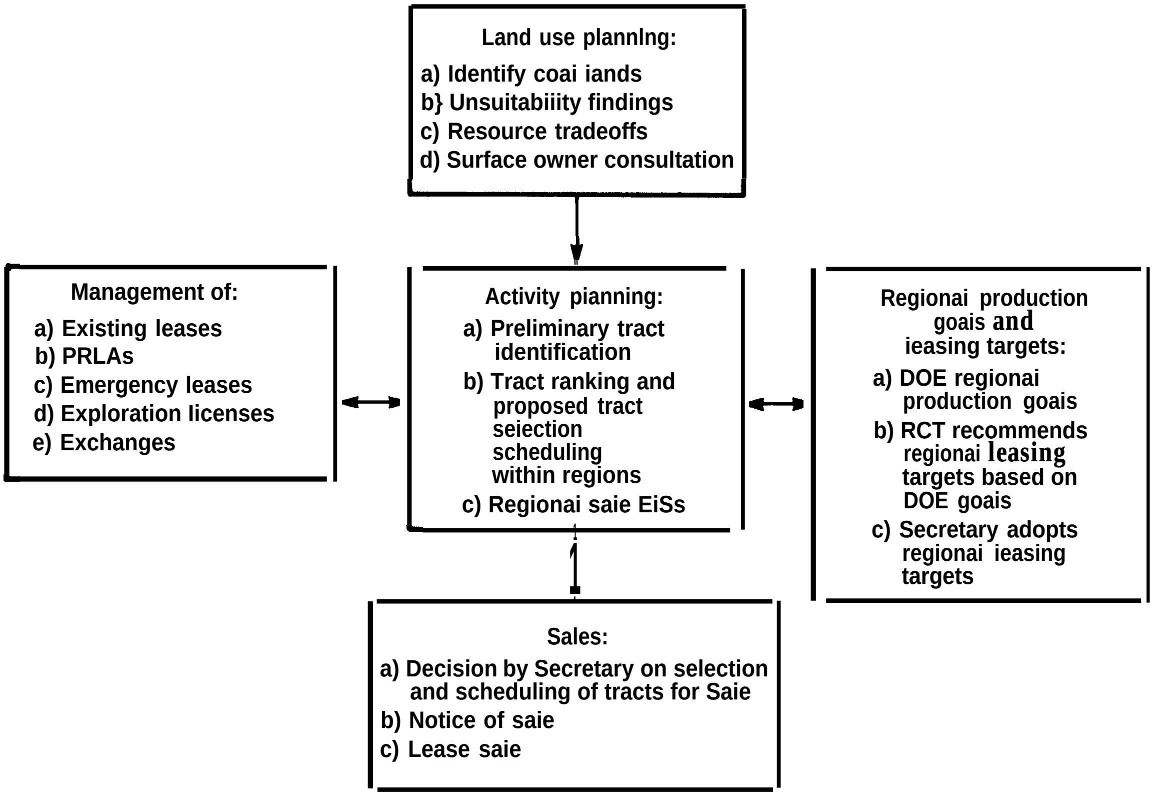
SOURCE Office of Technology Assessment

1979 Federal Coal Management Program

Under the 1979 coal management program, all Federal coal leasing is done under BLM's overall land use planning program established in section 202 of FLPMA. Figure 42 shows the lease planning and sales process under the July 1979 Federal Coal Management Program. The land use planning and coal management programs include a procedure for reviewing existing and potential leases to determine their suitability for mining according to a series of "unsuitability criteria. " Areas are only considered for leasing if they have a high to medium coal development potential and have been classified as a known recoverable coal resource area [KRCRA). DOI's unsuitability criteria are applied to these lands and a determination made as to whether the lands are suitable for leasing. Federal lands that have been leased also are reviewed for their suitability for mining during the general land management planning process and on mine plan approval. The use of unsuitability criteria for existing leases results in recommendations for mitigation requirements when a mine plan is proposed. The impact of the land use planning unsuitability criteria on pre-FCLAA leases is discussed more fully in chapter 10.

Several agencies and departments share responsibility for management and oversight of coal leases on Federal lands. Table 75

Figure 42.—Federal Coal Management Program: Department of the Interior Agency Involvement



Description of action	Agency involvement
Planning update — unsuitability criteria	BLM; FWS
Expressions of interest	BLM
Tract delineation	GS; BLM
Tract site-specific analysis	BLM; GS; OSM
Tract ranking	BLM; GS; FWS; OSM
Tract selection, scheduling, and analysis	BLM; GS; FWS
Regional EIS	BLM; GS; FWS; OSM; HC & RS; BR; BIA; Dept
DEIS printing and distribution	BLM
Public review period	BLM; GS; FWS; OSM; HC & RS; BR; BIA
PFEIS, development, and review	BLM; GS; FWS; OSM; HC & RS; BR; BIA
FEIS printing and distribution	BLM
DOE review, Governor's consultation	BLM
Secretarial review decision on FEIS	Secretary's office
Prelease sale activities	BLM; GS
Lease sale begin	BLM

Key.
BIA Bureau of Indian Affairs
BR: Bureau of Reclamation
DEIS: draft environmental impact statement
FEIS: final environmental impact statement
HC & RS: Heritage, Conservation, and Recreation Service
PFEIS: preliminary final environmental impact statement
RCT: regional coal team

SOURCE: U.S. Department of the Interior, Bureau of Land Management, June 1980.

Table 75.—Department of the Interior Division of Functions and Responsibilities Concerning Management of Federal Coal Between the Office of Surface Mining, the U.S. Geological Survey and the Bureau of Land Management (OSM, USGS, and BLM)

Function	Prime responsibility	Joint responsibility	In consultation with	Concurrence from
Preleasing functions				
Evaluate coal resources	USGS	—	—	—
Petition process for designation of Federal lands unsuitable for all or certain types of surface coal mining operations	OSM — Receives petitions — Conducts hearings — Issues decisions	Surface Management Agency and other appropriate State and local agencies	—	—
Federal coal lands review	BLM — Applies criteria in determination of suitability	—	OSM, USGS and other surface managing agencies	OSM — Establishes ground rules and criteria for Federal coal lands review
Preparation of regional EIS or site-specific prelease EIS concerning lease tract selection	BLM lead agency (unless other agency designated lead agency) — Relating to lease tract selection	—	OSM, USGS and other appropriate agencies and State and local interests	—
Preparation, special lease terms and conditions	BLM	—	OSM (responsibilities under SMCRA - to administer protection requirements of the act), USGS (responsibilities under the MLA)	USGS, OSM, and DOE
Act as Secretary's official representative in dealing with lease applicants	BLM	—	—	—
Surface owner consent	BLM (lease tract selection function)	—	—	—
Post/easing premining functions				
Prepare recommendations on applications for use of federally owned surface over leased coal for rights not granted in Federal coal lease	BLM	OSM and USGS (BLM receives applications) - prior to receipt of coal mining plan it is solely USGS responsibility to report on surface use application	USGS before mining plan; OSM after mining plan filed.	–
Delineation of "permit area"	None until mining plan filed, Then OSM assumes responsibility with concurrence of BLM and USGS	—	—	BLM and USGS
Review, approval of mining plans and major modifications; lead agency for preparation of site specific EA/EIS and coordination with other agencies outside DOI	OSM has lead responsibility (formerly assigned to USGS, became essential function of OSM under sec. 201, SMCRA)	BLM and USGS	BLM regarding special requirements relating to protection of natural resources; USGS regarding responsibilities relating to development, production and resource recovery requirements	USGS on production and recovery requirements
Exploration on leased coal lands outside a permit area	USGS receives application and supervises operations for all exploration outside a permit area	—	OSM	—

Table 75.—Department of the Interior Division of Functions and Responsibilities Concerning Management of Federal Coal Between the Office of Surface Mining, the U.S. Geological Survey and the Bureau of Land Management (OSM, USGS, and BLM)—Continued

Function	Prime responsibility	Joint responsibility	In consultation with	Concurrence from
Exploration on leased coal lands within a per-m it area	OSM	OSM and USGS coordinate a data exchange	USGS	USGS
Responsibility for all non-lessee activity on lease land prior to operations	BLM	—	—	—
Responsibility for deter mining performance bond	OSM (BLM for interim period)	—	—	—
Functions and responsibilities during mining operations				
Act as Secretary's representative in dealing with lessees and/or operators during operations	OSM (formerly USGS and BLM)	USGS retains production functions; OSM assumes environmental and enforcement functions; BLM retains nonmining functions outside the permit area, including rights-of-way and ancillary activities related to mining. USGS and BLM inspection in connection with USGS, BLM functions are coordinated with OSM inspections (except BLM inspections outside the permit area). USGS makes royalty audits and other non field inspections independent of OSM	—	—
Take necessary action in emergency environmental situation	OSM (formerly USGS and BLM)	OSM has primary emergency authority; BLM and USGS have such authority when OSM inspectors are unable to take action before significant harm or damage will occur. USGS and BLM retain their present procedures for emergencies involving loss, waste, or damage to coal and other natural resources and to other M LA functions	–	—
Conduct inspection prior to abandonment and specify and approve abandonment procedures	OSM (primary authority to approve abandonment procedures and approve abandonment of operations)	OSM, USGS, BLM - all have abandonment inspection responsibility	Private surface owner in case of private surface	BLM concurrence in approval of compliance, special requirements: protection of natural resources and post-mining land use of affected lands. USGS concurrence: compliance with production and coal resource recovery requirements.
Release of reclamation bond (permanent program)	OSM	—	—	BLM and USGS concurrence.
Release of lease bond	BLM	—	—	OSM and USGS concurrence.

NOTE: These agencies will also consult with the US Fish and Wildlife Service, both on a general basis, such as during land-use planning, and on a specific basis when required by laws such as The Endangered Species Act

SOURCE U S. Department of the Interior, Bureau of Land Management, *Final Environmental Impact Statement, Federal Coal Management Program,* April 1979, pp. 1-2 shows the division of functions and responsibilities among BLM, the U.S. Geological Survey (USGS), and the Office of Surface Mining (OSM) within DOI for the administration of the Federal coal management program, BLM is the lead agency for implementing DOI's preleasing and leasing functions; OSM is responsible for processing designation petitions and coordinating mine plan review; and USGS is responsible for evaluating the coal resource and enforcing Mineral Leasing Act requirements and collecting lease revenues from production. The Fish and Wildlife Service is consulted on matters involving wildlife and potential impacts on refuges. The Forest Service of the Department of Agriculture becomes involved as the surface management agency for lands in national forests. In addition, the Department of Energy (DOE) shares responsibility with DOI for setting production levels, bidding systems and diligence requirements on Federal energy mineral leases.[18]

As part of the coal management program cooperative Federal-State regional coal management teams were formed which institutionalize the requirements in FCLAA for consultation with State and local governments before leasing. The regional coal teams include representatives of the Western Governors who make specific recommendations to the Secretary of the Interior on where, how much, and when coal should be leased on Federal lands.

DOI and DOE were given collateral responsibilities for establishing regional coal production goals and leasing targets. DOE periodically issues national and regional production goals. These goals in turn are considered by DOI in establishing regional leasing targets. These production goals and leasing targets are used by the regional coal management teams in the "activity planning process" which advises the Secretary on the tract selection, ranking and scheduling proposed lease sales in the regions.

Establishing regional production goals and leasing targets is done in two stages: 1) tract delineation and industry expressions of interest in each land-use planning area; and 2] tract ranking, selection and scheduling, considered over the entire coal region. In delineating tracts, BLM considers the interests of the industry, technical data provided by USGS and the States, MER estimates of USGS, potential LMUs, surface ownership, and regional leasing targets.

Final regional tract ranking, selection and scheduling of lease sales is based on two determinations: 1) a site-specific environmental analysis of the proposed tracts and 2) the regional coal team recommended ranking of the tracts (high, medium, or low) considering geological and economic factors and potential environmental and socioeconomic impacts of mining. At every stage in the overall leasing program, public participation is encouraged through open meetings of regional coal teams, public hearings, opportunities for comment and review during the leasing target and EIS processes. Most of this public participation and consultation with State and local governments is required by FCLAA, After the planning, target setting, tract selection and ranking are completed, the tracts are offered for sale by competitive bid. The first sale under the new program was held in early 1981 in the Green River-Hams Fork region and included one small tract under a special small business set aside arrangement.

Legal Issues Relating to Existing Federal Leases

Of the 565 Federal leases in effect on September 30, 1980, 535 leases containing nearly all of the Federal coal reserves under lease were issued before enactment of FCLAA, and are thus subject in part to different legal requirements than leases issued after FCLAA.

This section examines some of the major legal issues related to the development and management of existing Federal leases and PRLAs including:

- diligent development, and the related concepts of continued operation, LMUS, advance royalties, maximum economic recovery and cancellation;
- exchanges of reserves under existing leases and PRLAs for unleased Federal reserves;
- processing and validity of pending PRLAs; and
- designation of areas on existing leases that are unsuitable for surface mining under section 522 of SMCRA.

Diligent Development and Related Concepts

The concept of "diligent development" of Federal coal leases evolved over a period of time. A number of legal uncertainties still surround its practical application to existing leases. There are several other important concepts that are either directly or indirectly related to diligent development: 1) requirements in the 1920 Mineral Leasing Act for continued operation of a lease once diligent development is achieved, 2) definition of LMUs and logical mining unit reserves to which diligent development and continued operation requirements apply, and 3) advance payment of royalties either to encourage diligent development, or in lieu of requirements for continued operation.

Common Law Diligence

Diligent development as an implied covenant of mineral leases originated in common law. Under the Mineral Leasing Act, diligent development is an express condition of every Federal lease. The condition of diligent development imposes an obligation on the lessee to produce the mineral so that the lessor receives the agreed royalty to fulfill the lessor's interest in the contract.

As applied to private mineral leases under common law, the courts have generally defined diligence as requiring the lessee to "do whatever under the circumstances would be reasonably expected of a prudent operator of a particular lease, having a rightful regard for the interests of both the lessor and the lessee."[19] Market considerations can be taken into account, however, absence of a market is not grounds for indefinite deferral of production. Each case is decided on its specific circumstances. Lease provisions can provide more specific diligence standards such as requiring production to commence within a definite time period or allowing the lessee to pay advance royalties instead of producing.

Compensation for the rights to explore and develop mineral resources is often paid in a two-part process. The initial rights to enter, explore, and develop a leasehold are granted to lessees in exchange for payment of a fee (bonus) generally made at the time the lease is executed. The second payment is a continuous periodic payment of royalties, usually based on a percentage of the value of the product. To ensure that the lessor received some periodic payment even in the absence of production, annual rentals are sometimes negotiated that are based on minimal payments for holding the lease,

The size of the bonus payment is generally proportional to the probability of finding and producing minerals at a profit. If the probability of discovering commercial high-grade resources is high, the bonus payment will be large. If the probability of commercial discovery and economic production is highly uncertain, the bonus payment will be low.

Since royalties are not received until production begins, and production must continue or the royalties will cease; a condition (stipulation) requiring continued operation is often included in a lease agreement to ensure that production and income continue. Failure to pursue diligent development of the leasehold and to continue production constitutes a breach of the lease contract. The most viable remedy available to a lessor harmed as the result of a contractual breach is cancellation of the lease, and if the lessor choses, resale of the lease to one who will develop the leasehold.

The 1976 Diligence Regulations

Although all pre-FCLAA coal leases by statute must contain both the conditions of diligent development and continued production, enforcement of these provisions were rare until 1976 when the terms and meaning of the provisions were defined by rulemaking. Between 1920 and 1976, various lease terms had imposed minimum investment and production requirements and advance royalties, but these provisions were not applied universally to all leases.[20]

In response to an unprecedented period of greatly expanded leasing during a time of decreasing Federal coal production, DOI began grappling with the problem of diligence in lease development in 1970. Its initial efforts concentrated on policies aimed at applying economic leverage on lessees to ensure production, e.g., such as gradually increasing advance payment royalties, which would require front-end payments that would be offset against future production. Congress, however, preferred the establishment of specific time limits for development, therefore, in 1974-1975 DOI proposed regulations that defined diligent development and set time limits for performance, but also retained the option for advanced royalty payments (see table 76 summarizing proposed and final regulations on diligent development). Final regulations were promulgated by DOI in May 1976 shortly before passage of FCLAA,[21] With the approval of the 1976 FCLAA, a dual system governing diligent development was established, The legal effect was to create two similar, but not identical diligence standards, one applying to leases issued before to August 4, 1976 (pre-FCLAA), and the second applying to leases issued after that date (post-FCLAA). These regulations have remained largely unchanged since repromulgation in December 1976 to include FCLAA requirements.[22] The Department of Energy Organization Act of 1977 transferred the Secretary of the Interior's authority to issue regulations on diligence for Federal leases to the Secretary of Energy.[23] The Secretary of the Interior retains the responsibility for enforcement, but he cannot change these regulations.

Summary of Diligent Development and Continuous Operations Regulations

Section 7 of the Mineral Leasing Act of 1920 requires that all Federal coal leases are subject to diligent development and continuous operations. Lessees failing to meet these conditions can lose their Federal coal leases. Moreover, under section 3 of FCLAA, after August 4, 1986, with few exceptions, lessees who have held a nonproducing lease for 10 years or more cannot obtain any new Federal coal leases.[24]

In 1976, DOI issued regulations defining diligent development for Federal coal leases as timely preparation for and actual production of coal in commercial quantities from the lease, or from the LMU of which the lease is a part, by June 1, 1986 or within 10 years after the lease is issued, whichever is later.

These regulations established two separate standards for diligent development of Federal leases by defining commercial quantities differently for pre-FCLAA and post-FCLAA leases. Commercial quantities for pre-FCLAA leases are defined as "production

Table 76.—Changes in Definitions of Diligent Development and Continued Operation, Proposed and Final Regulations (1974-79)

Source	Diligent development	Continued operation
Federal Register Dec. 11, 1974 (Proposed) 39 F.R. 43229	Diligent development means: preparing to extract coal from an LMU in a manner and at a rate consistent with a mining plan approved by the mining supervisor. Qualifying activities and expenditures include environmental monitoring and baseline studies, geological and geophysical studies, engineering feasibility studies, mine development and construction work, and contracts for purchase or lease of equipment undertaken for the purpose of obtaining production from the LMU. Lessee must report on activities in support of diligent development to mining supervisor every 2 years and indicate plans for continuing diligent development for following 2-year period.	Continuous operations defined as: extraction, processing, and marketing of coal in commercial quantities from the LMU without interruptions totaling more than 6 months in any calendar year except as provided in 30 U.S.C. 207 and in the lease.
Federal Register Dec. 31, 1975 (Reproposed) 40 F.R. 60070	Diligent development means timely preparation for and initiation of production from the LMU of which the lease is a part so that one-fortieth of the LMU reserves associated with the lease are extracted within 10 years from the effective date of the regulation or issuance of the lease, whichever is later. Additional time for meeting diligence may be granted for a period equal to the time during which diligent development was significantly impaired by: 1. a strike, the elements or casualties not attributable to the lessee; 2. an administrative delay in the DOI not caused by the lessee's action; or 3. extraordinary circumstances not attributable to the lessee and not foreseeable by a reasonably prudent operator (extraordinary circumstances do not include: conditions arising out of normally foreseeable business risks such as fluctuations in prices, sales, or costs, including foreseeable costs of environmental protection requirements; commonly experienced delays in delivery of supplies or equipment; or inability to obtain sufficient sales).	Continuous operations defined as extraction, processing, and marketing of coal from the LMU after diligent development has been achieved in an amount of 1 percent or more of the LMU reserves in each calendar year subject to the exceptions in 30 U.S.C. 207 and in the lease.
Federal Register May 28, 1976 (Final) 41 F.R. 21779	Diligent development defined as: timely preparation for and initiation of production from the LMU of which the lease is a part so that one-fortieth of the LMU reserves associated with the lease are extracted within a period of 10 years from the effected date of the regulations (i.e., by June 1, 1986) or from the issuance of the lease, whichever is later. Extensions may be granted for time during which diligent development is substantially impaired by: 1. a strike, the elements or casualties not attributable to the lessee; 2. an administrative delay in the DOI not caused by the lessee's action; or 3. extraordinary circumstances not attributable to the lessee and not foreseeable by a reasonably prudent operator. An extension may also be granted for up to 5 years (i.e., to June 1, 1991) if the lessee cannot meet diligence because of: —time needed for development of an advanced technology (e.g. in situ gasification or liquefaction processes); —the large magnitude of the project (ordinarily 2 million tons per year for an underground mine and 5 million tons per year for a surface mine); or —a contract or equivalent firm commitment for the sale of the first 2½ percent of the LMU reserves after the 10-year period.	Continuous operations defined as the extraction, processing, and marketing of coal in the annual average amount of 1 percent or more of the LMU reserves computed on a 3-year basis including the 2 previous years. With approval of the mining supervisor, advance royalties may be paid in lieu of continuous operations for leases issued or readjusted after the effective date of the regulations,

Table 76.—Changes in Definitions of Diligent Development and Continued Operation, Proposed and Final Regulations (1974-79)—Continued

Source	Diligent development	Continued operation
Federal Register Oct. 15, 1976 (Proposed) 41 F.R. 45571	For pre-FCLAA leases not readjusted after Aug. 4, 1976, diligent development means timely preparation for and initiation of production from the LMU of which the lease is a part so that coal is actually produced in commercial quantities by June 1, 1986 (commercial quantities is defined as production of one-fortieth of the LMU reserves associated with the lease). Extensions may be granted under the same conditions as in the May 1976 final regulations, but the period for meeting diligence cannot be extended beyond Aug. 4, 1986, or the date the lease is first subject to readjustment after FCLAA, whichever is later For post- FCLAA leases and all readjusted pre-FCLAA leases, diligent development means timely preparation for and initiation of production from the LMU of which the lease is a part so that coal is actually produced in commercial quantities (defined as 1 percent of the LMU reserves) by 10 years after the effective date of the lease or by June 1, 1986 or by the date on which the pre-FCLAA lease is first subject to readjustment after FCLAA, whichever is later. Extensions granted to pre-FCLAA leases can continue in effect after readjustment, but only until Aug. 4, 1986.	‘Continued operation means the extraction, processing, and marketing of coal in the amount of 1 percent of all the LMU reserves associated with the lease for each of the first 2 years of continued operation and in an annual average amount of 1 percent of all the LMU reserves associated with the lease for all following years The annual average amount will be calculated on a 3-year basis with the 2 preceding years
Federal Register Dec. 29, 1976 (Final) 41 F.R. 56643	For pre-FCLAA leases: Diligent develop-merit means timely preparation for and initiation of production from the LMU of which the lease is a part so that coal is actually produced in commercial quantities (defined as one-fortieth of the LMU reserves) by June 1, 1986 Extensions may be granted under same conditions as May 1976 final regulations. For post. FCLAA leases: diligent development means timely preparation for and initiation of production from the LMU of which the lease is a part so that coal is actually produced in commercial quantities (defined as 1 percent of the LMU reserves) within 10 years from the effective date of the lease (No provisions for any extensions for post-FCLAA leases are included in the regulations.)	Continued operation means production of 1 percent of the LMU reserves in each of the first 2 years after meeting diligence, and production at an annual average rate of 1 percent of the LMU reserves thereafter. The annual average rate is calculated on a 3-year basis with the 2 previous years
Federal Register Mar. 19, 1979 (Proposed) 44 F.R. 16800	No substantive changes proposed to December final regulations (The authority to promulgate rules relating to diligence and minimum production requirements for Federal leases was transferred to the Secretary of Energy by section 302 of the Department of Energy Organization Act)	No substantive changes proposed to December 1976 final regulations
Federal Register July 19.1979 (Final) 44 F R 42583	No substantive changes to December 1976 final regulations—relevant sections renumbered as part of new coal management program regulations	No substantive changes to December 1976 final regulations-relevant sections renumbered as part of new coal management program regulations.

NOTE This table generally summarizes the regulations rather than quoting them in full.

of one fortieth (21/2 percent) of the recoverable reserves of the LMU of which the lease is a part. ” For post-FCLAA leases, commercial quantities are defined as “production of one percent of the lease’s LMU reserves within 10 years after lease issuance, ” Under certain circumstances, the diligence period can be extended for pre-FCLAA leases,

Logical Mining Units

The current regulations define diligence and continuous operations requirements according to LMUS rather than leases. The basis of the LMU concept, as generally understood, is that geological and engineering characteristics should delineate the boundaries of the area that can be leased and mined economically with appropriate environmental safeguards. In practice, however, the legal right to mine coal often dictates the area to be developed, which can result in a less than optimal mining unit, especially in areas with scattered and diverse ownership. The concept, with some modification, was incorporated into the 1976 diligence regulations and FCLAA. The regulations currently define an LMU as:

> .,. an area of coal land that can be developed and mined in an efficient, economical, and orderly manner with due regard for the conservation of coal reserves and other resources. An LMU may consist of one or more leases and may include intervening or adjacent non-Federal lands, but all lands in an LMU must be contiguous, under the effective control of a single operator, and capable of being developed and operated as a unified operation with complete extraction of the LMU reserves within 40 years from the date of first approval of a mining plan for that LMU. No LMU approved after August 4, 1976, shall exceed 25,000 acres, including both Federal and non-Federal coal deposits.[25]

Notwithstanding this definition, the rules also provide that "each lease shall automatically be considered to constitute an LMU on the effective date of the lease or June 1, 1976, whichever is later.[26] The single lease LMU can later be modified to add other Federal or non-Federal coal with the approval of DOI, but the enlarged unit must meet the general LMU criteria. The single lease LMU was established in the May 1976 regulations primarily for administrative convenience in applying diligent production requirements, however, it was reinforced at least indirectly by section 5 of FCLAA which requires the lessee's consent before pre-FCLAA leases can be consolidated into a designated LMU under that section. Table 77 summarizes the development of the LMU concept in DOI regulations.

For pre-FCLAA leases, the LMU is determined by the lease boundaries, and the LMU reserves for diligence and continuous requirements are the recoverable reserves of the lease unless the lessee petitions either to have the LMU boundaries modified to include other Federal leases or non-Federal coal or to relinquish portions of the lease reserves that will not be mined. If a new LMU is designated, the aggregate production from all lands in the unit can be used to meet diligence for all producing and nonproducing leases in the unit.

Diligence Extensions

Extensions can be approved for pre-FCLAA leases for delays in meeting diligence because of conditions that are beyond the control of the lessee. These extensions are required by sections 7 and 39 of the Mineral Leasing Act.[27] These nondiscretionary extensions are granted for a period of time equal to the time during which diligence is impaired by: strikes, weather conditions, casualties, Government delays, or extraordinary circumstances that are not the fault of the operator. Regulations on whether and under what circumstances nondiscretionary extensions might be available to post-FCLAA lessees have not yet been promulgated.[28]

In determining whether such extraordinary circumstances exist, the regulations specifically exclude "any condition arising out of normally foreseeable business risks such as: fluctuations in prices, sales, or costs, including foreseeable costs of compliance with requirements for environmental protection; commonly experienced delays in delivery of supplies or equipment; or inability to obtain sufficient sales. '[29]

The pre-FCLAA lessee can also apply for a single extension of up to 5 years, i.e., up to June 1, 1991, under certain circumstances. These discretionary extensions may be granted for: 1) additional time for developing new coal technologies, such as synfuels or nonwater-based coal slurry pipelines; 2) extraordinarily large or complex mining operations (generally exceeding 2 million tons per year for underground mines and 5 million tons per year for surface mines); or 3) firm contracts to produce and deliver the first 2½

Table 77.—Changes in Definitions of Logical Mining Unit and Logical Mining Unit Reserves Proposed and Final Regulations (1974.79)

Source	Logical mining unit	Logical mining unit reserves
Federal Register Dec. 11, 1974 (Proposed) 39 F.R. 43229	An LMU is a compact area of coal land that can be developed and mined in an efficient, economical, and orderly manner with due regard for conservation of coal reserves and other resources and in accordance with an approved mining plan, The LMU may consist of one or more Federal leaseholds and may Include Intervening or adjacent non-Federal lands insofar as all lands are under the effective control of a single operator. Mining supervisor (MS) authorized to approve or establish an LMU. All leases must be included in an LMU within 2 years from effective date of regulations If the lessee IS unable after a good faith effort to form an LMU as defined in the regulations, a single lease will be treated as an LMU for diligence and reporting requirements.	No definition proposed
Federal Register Dec. 31, 1975 (Reproposed) 40 F.R. 60070	An LMU IS an area of coal land that can be developed and mined in an efficient, economical, and orderly manner with due regard to the conservation of the coal reserves and other resources. An LMU may consist of one or more Federal leases and may Include Intervening or adjacent non-Federal lands, if all lands are under the control of a single operator and can be developed and operated as a unified mine. The MS IS authorized to approved or establish an LMU. Every Federal lease wiIl automatically be considered an LMU; the LMU boundaries may later be changed: 1. at request of lessee with approval of MS with concurrence of BLM; 2 at discretion of MS with concurrence of BLM; 3. at request of BLM with approval of MS.	As of a given date LMU reserves are the sum of 1) estimated recoverable Federal reserves under lease in the LMU, and 2) estimated non-Federal recoverable reserves that wiIl be mined before extraction of all Federal reserves in the LMU. Federal LMU reserves will be the estimated reserves on the effective date of regulations—or the date of the lease, whichever is later, Reserves may be adjusted by MS whenever significant new information becomes available about the amount of such reserves, including the time at which *a mining plan IS* approved for the Federal portion of the LMU.
Federal Register May 28, 1976 (Final) 41 F.R. 21779	An L-MU IS an area of-coal land that can be developed and mined in an efficient, economical, and orderly manner with due regard to the conservation of the coal reserves and other resources. An LMU may consist of one or more Federal leases and intervening or adjacent non-Federal lands, but all lands in an LMU must be under the effective control of a single operator and capable of being developed and operated as a unified mine Every lease wiIl automatically be considered by itself an LMU as of the effective date of the lease or the regulations, whichever IS later, Any LMU other than a single Federal lease wiIl become effective only on its approval by the MS where it IS requested by the lessee. Boundaries of LMU may later be changed on application by the lessee and with approval of the MS and after consultation with BLM.	As of a given date, LMU reserves are the sum of 1) estimated recoverable Federal reserves under lease in the LMU, and 2) estimated non-Federal recoverable reserves that wiIl be mined before extraction of all the Federal reserves in the LMU. LMU reserves associated with a Federal lease are the estimated LMU reserves as of effective date of approval of LMU. LMU reserves may be modified when MS approves modification of LMU boundaries or whenever significant new information becomes available about the amount of recoverable reserves including when a mine plan IS approved
Federal Register" Oct. 15, 1976 (Proposed) 41 F.R. 45571	An L-MU IS an area of coal land that can be developed and mined in an efficient, economical, and orderly manner with due regard for conservation of the coal reserves and other resources. An LMU may consist of one or more Federal leases and intervening or adjacent non-Federal lands, but all lands in the LMU must be contiguous, under the effective control of a single operator and capable of being developed and operated as a unified operation with complete extraction of the LMU reserves within 40 years of first approval of the mine plan for the LMU, No LMU, except those approved before Aug 4, 1976, can exceed a total of 25,000 acres of Federal and nonfederal lands,	Definition of LMU reserves is the same as May 1976 final regulations. The estimated LMU reserves may be adjusted by the MS whenever a modification of the LMU boundaries IS approved, or the lessee surrenders deposits under lease in the LMU, or whenever additional Information becomes available about the amount of such reserves including when a mine plan is approved,

Table 77.—Changes in Definitions of Logical Mining Unit and Logical Mining Unit Reserves Proposed and Final Regulations (1974-79)—Continued

Source	Logical mining unit	Logical mining unit reserves
	Notwithstanding the above definition, every Federal lease will automatically be considered an LMU on the effective date of the lease or June 1, 1976, whichever is later. An LMU other than a single lease LMU will become effective only at the direction of the MS or by approval of the MS at the request of the lessee. (These designated LMU's must meet the requirements of section 5 of FCLAA.)	
Federal Register Dec. 29, 1976 (Final) 41 F.R. 56643	Unchanged from October 1976 proposed regulations,	Logical mining unit reserves are the sum of 1) estimated recoverable Federal reserves under lease in the LMU and 2) estimated non-Federal recoverable reserves in the LMU. The LMU reserves associated with the Federal lease are the estimated recoverable reserves on the effective date of the LMU. The LMU reserves may be adjusted by the MS whenever the LMU is modified, or the lessee surrenders deposits in the LMU, or whenever significant new information becomes available about the amount of such reserves including when a mine plan is approved.
Federal Register July 19, 1979 (Final) 44 F.R, 42583 now 43 CFR 3400.0-5	An LMU is an area of coal land that can be developed and mined in a efficient, economical, and orderly manner with due regard for the conservation of coal reserves and other resources. An LMU may consist of one or more leases and may include intervening or adjacent non-Federal lands, but all lands in the LMU must be contiguous (i.e., having one point in common, including cornering tracts), under the effective control of a single operator, and capable of being developed and operated as a unified operation with complete extraction of the LMU reserves within 40 years from the date of first approval of the LMU mine plan. No LMU approved after Aug. 4, 1976 may exceed a total of 25,000 acres of Federal and non-Federal lands. Notwithstanding the above definition, every Federal lease will automatically be considered an LMU on the effective date of the lease or June 1, 1976, whichever is later. An LMU, other than a single lease LMU, will become effective only on approval by the MS on application by the lessee, or by direction of the MS, or by designation during the normal tract delineation phase of the coal activity planning process. The MS will not approve the designation of such an LMU unless maximum economic recovery of all the Federal coal deposits in the LMU will be achieved.	LMU–reserves mean the sum of 1) estimated recoverable reserves under Federal lease in the LMU, and 2) estimated non-Federal recoverable reserves in the LMU. The Federal lease LMU reserves are estimated as of the date the LMU becomes effective. The LMU reserves may be adjusted by the MS whenever the LMU boundaries are modified or when significant new information becomes available on the amount of such reserves.

NOTE' This table generally summarizes the regulations rather than quoting them in full

percent of the coal after the lo-year period.[30] These discretionary extensions are not available for post-FCLAA leases.

Continuous Operations

After attaining diligence, both pre-FCLAA and post-FCLAA lessees must meet the continuous operations requirements. The regulations define continuous operations for all Federal leases as production of an average of 1 percent of the LMU reserves annually, with 1 percent produced in each of the 2 years immediately following the year in which the lessee meets diligence. With approval of DOI, the lessee can pay advance royalties in lieu of actual production in order to satisfy continuous operations requirements. Such advance royalty payments, however, cannot be made in lieu of continued operation for more than 10 years during the life of the lease. Continuous operations requirements for pre- and post-FCLAA leases can be suspended during periods when production is interrupted because of conditions beyond the control of the lessee. Minimum annual production requirements can also be lifted when operations on the lease are suspended with the approval of the mining supervisor to promote conservation of coal resources. Table 76 shows the development of continuous operations regulations.

Advance Royalties

Advance royalties are commonly used by private coal lessors to ensure that mine production stays on schedule. If production proceeds according to the predetermined schedule, the lessee continues to pay the regular royalty, but if production is lower than scheduled, advance royalties are collected on the difference between scheduled and actual production. The purpose for using advance royalties is to provide a financial incentive for the lessee to develop the lease.

Advance royalties have been used in several ways in pre-FCLAA leases: 1) in lieu of continued operation requirements for leases issued between 1920 and 1971; 2) as an incentive to begin production for leases issued during the moratorium between 1971 and 1976 by requiring payment of advance royalties beginning in the sixth year after issuance of the lease based on a predetermined schedule (similar to the way advance royalties are used in the private sector); and 3) in lieu of continued operation for up to 10 years during the term of the lease as allowed by FCLAA.[32]

Advance royalties are currently based on an annual production rate that would exhaust the mine reserves in 40 years (2.5 percent per year) .33 This rate is higher than the 1 percent rate required to satisfy continuous operation regulations and thus is an incentive to produce.

Cancellation of Leases

Under section 31 of the Mineral Leasing Act of 1920 if the lessee fails to comply with the terms of the lease, a provision of the act, or general regulations issued under the act that were in force at the date of the lease, the Secretary may ask the Justice Department to sue in Federal court to have the lease forfeited and canceled.[34] For pre-FCLAA lessees, breach of the conditions of diligent development or continued operation could result in cancellation of the lease in court proceedings if the court decided that the lessee did not meet diligence because he or she did not satisfy the minimum production defined in the 1976 regulations (or some other standard).[35] Section 6 of FCLAA provides that any post-FCLAA lease not producing in commercial quantities 10 years after issuance shall be terminated automatically. Termination is an administrative proceeding and is subject to judicial review. The May 1976 DOI regulations limited the circumstances that the Secretary could consider in deciding whether to cancel a lease for failure to meet diligence by generally excluding lack of markets.[36] Both pre- and post-FCLAA leases must be canceled through court proceedings brought under the general provisions of section 31 for any other breach of the lease terms or conditions, or for violation of the act or DOI regulations.

Application of the 1976 Diligence Requirements to Existing Leases

Since 1976, DOI has maintained that the 1976 diligence regulations are general regulations implementing the Mineral Leasing Act which are applicable to all coal leases and that the regulations, thus, need not be made specifically part of individual leases through amendment or readjustment. The diligence regulations and other aspects of the coal management program are currently under review by the Reagan administration and could be modified. Whether or not the 1976 regulations are eventually held to be generally applicable to all leases, under certain circumstances the diligence requirements can be made part of individual leases: 1) by voluntary amendment of the lease terms by mutual agreement between DOI and the lessee; 2) by readjustment at the end of the lease term; 3) by amendment as part of the designation of a new LMU under section 5 of FCLAA; or 4) by operation of existing lease terms incorporating future regulations. If the requirements are specifically incorporated into a lease, they are clearly applicable and enforceable for that lease.

Voluntary Amendment

At the request of DOI, some lessees have voluntarily agreed to lease revisions incorporating the diligent production requirements. In other instances, DOI could negotiate the lessee's consent to revise the lease to include the 1976 regulations as part of another transaction involving the lease, such as a modification or segregation, or in exchange for DOI's agreement not to move immediately to enforce the minimum production requirements contained in some existing leases.[37]

Readjustment

Pre-FCLAA leases were originally issued for indeterminate periods subject to readjustment of lease terms, conditions, rentals and royalties at the end of each 20-year period following issuance. The Secretary of the Interior has broad discretion in setting new lease terms. Readjustment generally results in incorporating any changes in the laws and regulations governing leases that were not applicable at the time the original lease was issued. At readjustment, pre-FCLAA diligence requirements are expressly made part of the new lease terms. If the new terms are unacceptable, the lessee can either: 1) decline extension of the lease; or 2) appeal or protest the revised terms. Leases readjusted after August 4, 1976 are to include the 1976 diligence requirements that apply to pre-FCLAA leases. About 244 pre-FCLAA leases are due for readjustment before June 1, 1986. Over 200 pre-FCLAA leases are not due for readjustment until after the initial 1986 diligence "deadline,"

Amendment of Lease Terms on Designation of a Section 5 LMU

Under section 5(b)(4) of FCLAA, when one or more leases, including pre-FCLAA leases with the consent of the lessee, are consolidated into an LMU, the provisions of any Federal lease in the LMU may be amended so that mining will be consistent with the requirements imposed on that logical mining unit.[38] Although "consistency" is not defined and the Secretary is not required to amend the lease, the LMU designation may be used as an opportunity to provide for express application of diligence regulations to leases within the LMU. However, such revision would require the lessee's consent.

As another result of an LMU designation under section 5(b)(3) of FCLAA, the Secretary may (but is not required to) provide, "among other things, that (i) diligent development, continuous operation, and production on any Federal lease or non-Federal land in the logical mining unit shall be construed as occuring on all Federal leases in that logical mining unit . . ." Since approval of an enlarged LMU is discretionary, the lessee's consent to include the 1976 diligence requirements as a stipulation in the lease might be used as a condition for obtaining an LMU approval.[39]

Existing Lease Terms That Incorporate Subsequent Regulations

Federal coal leases issued or renewed after 1965 contain a provision in the initial clause of the lease stating that the lease is issued:

> . . . pursuant and subject to the terms and provisions of (the Mineral Leasing Act of 1920), and to all reasonable regulations of the Secretary now or hereafter in force which are made a part hereof . , .[40]

By accepting the lease with this provision (referred to as the "hereafter clause"), the lessee has specifically agreed to be bound by future "reasonable regulations" made applicable to existing leases without the necessity of formally amending the lease terms. As a result of this express agreement, leases with this clause are subject to the 1976 diligence regulations by operation of the prior lease term. Violation of the subsequent regulations would, therefore, be a violation of the lease provisions and make the lease subject to cancellation under section 31 of the Mineral Leasing Act.[41] The reasonableness of any subsequent regulations would be determined according to general principles of administrative law if the issue were ever litigated. The hereafter clause has been used in thousands of other Federal mineral leases for over 45 years, The meaning of the “hereafter clause” and its impact on the applicability of the 1976 diligence regulations on coal leases have not yet been judicially construed.

Legal and Administrative Issues in the Enforcement of Diligence Requirements

The impact of the 1976 diligence regulations on Federal coal leases is uncertain. The regulations requiring actual production within 10 to 15 years were generally opposed by the coal industry, and the major industry trade groups. The National Coal Association and the American Mining Congress, have continued to criticize the policy.

While many lessees have accepted the 1986 deadline, and many will in fact meet diligence by then (see ch. 6 of this report), legal challenges are likely if DOI enforces the requirements against those lessees who are not in compliance. Among the major legal objections which the industry has raised are: I) the regulations are arbitrary, unreasonable and exceed the Secretary’s authority under the Mineral Leasing Act because of the stringent compliance period imposed and the lack of flexibility in measuring diligence as production of 2½ percent of the LMU reserves; 2) the regulations violate the Mineral Leasing Act by imposing new terms and conditions on the lessee which can only be done at readjustment; 3) the regulations are ineffective to the extent that they conflict with specific lease provisions; and 4) the regulations abridge the lessee’s contractual rights, thus, violating the constitutional prohibition against deprivation of property without due process of law or just compensation.

The only litigation challenging the application of the diligence requirements in the 1976 regulations to pre-FCLAA leases, Mobil Oil Corp. v. Andrus, was settled out of court and thus did not establish any precedent.[42] As a result of the settlement, Mobil received approval of a 5-year extension in the period for meeting diligence for its 1971 lease.

The possible difficulties in enforcing DOI’s diligence regulations were recognized in the Secretarial Issue Document for the Federal Coal Management Program,” One of the major uncertainties is the absence of a prior enforcement history for diligence for Federal coal leases. Before promulgation of the 1976 regulations, DOI had not issued formal rules defining diligent development nor had it canceled any coal lease for failure to meet diligence. As an added complication, many lease forms contain provisions requiring minimum production beginning in the sixth year of the lease. Without the adoption of the 1976 regulations superseding the lease terms and giving 10 to 15 years to meet diligence, many nonproducing lessees would already be in violation of their lease provisions. Ultimately, the issue of the validity and applicability of the 1976 regulations may be decided by the courts. The range of possible results of such challenges include:

- The 1976 diligent development regulations are valid and fully applicable to all leases because all leases are subject to the conditions of diligence required in the 1920 Mineral Leasing Act and to the departmental regulations implementing these requirements, (the position of DOI in Mobil.)44
- The 1976 regulations are invalid and not applicable to pre-FCLAA leases because nothing in the 1920 Mineral Leasing Act authorizes the Secretary to define diligence solely as achieving specified production levels within a definite period of time. (Note: The Mineral Leasing Act and common law diligence conditions would still be applicable although the precise standard to be used would remain undefined.)

94-141 c1 - 81 - 17 : ‘II, 3

- The 1976 diligence regulations are valid but are applicable to pre-FCLAA leases only on readjustment at the end of their current 20-year lease terms or by amendment of lease terms with consent of the lessee either in response to DOI's request or as a possible precondition of approval for designation of a combined LMU under section 5 of FCLAA or other discretionary administrative action.
- The 1976 regulations are valid and applicable to pre-FCLAA leases to the extent that they are consistent with the specific terms and conditions of individual leases issued before the regulations became effective. The regulations would apply to leases containing the "hereafter clause" which incorporates future regulations, as well as to any leases issued before 1965 that include provisions which do not establish different minimum production levels or advance royalty payments to satisfy diligence conditions.

Leases issued after the 1976 FCLAA are clearly subject to the diligent development regulations promulgated under that act and must produce coal in commercial quantities within 10 years after issuance or they will be terminated.

The eventual impact of diligence requirements on pre-FCLAA leases will depend on the interaction of many variables besides the legal precedents that may be established on the applicability of diligence regulations. These factors include: 1) the extent of voluntary compliance by lessees; 2) how many extensions are granted to lessees who cannot meet the 1986 production deadline; 3) how many existing leases are combined with other leases or non-Federal coal reserves to meet diligence by forming a designated LMU under section 5 of FCLAA; 4) how the logical mining unit reserves are defined for each lease; 5) the extent to which leases are readjusted on schedule; 6) the extent of effective enforcement of the 1976 regulations by DOI and the Department of Justice; and 7) how many nonproducing leases are relinquished.

Determination of LMU and LMU Reserves for Diligence

Whether or not some existing leases will meet diligence depends on the USGS determinations of LMU and LMU reserves against which compliance is gaged. There are two kinds of LMUs for the purpose of diligence: 1) single lease LMUs and 2) designated LMUs under section 5 of FCLAA. All existing leases are single lease LMUs under current regulations. Section 5 of FCLAA prohibits consolidation of any pre-FCLAA lease into an LMU without the lessee's consent and no section 5 LMUs had been approved by USGS as of early 1981.

Single lease LMUs are based on the general authority of the Secretary to manage coal leases under the Mineral Leasing Act of 1920 and the regulations originally promulgated in May 1976 before passage of FCLAA. These LMUs consist of the reserves in a single lease that can be mined efficiently and economically with due regard for conservation of the coal resource and other values. They need not consist of a separate mine or mine plan for each single lease LMU. Single lease LMUs need not be contiguous, nor must they be mined out in 40 years. The major difficulty in defining the LMU reserves for single leases occurs in determining which seams to include when the lease has large multiple-seam reserves either that would not be mined in the lessee's normal sequence and method of mining or that do not meet the lessee's coal quality requirements under existing contracts. Each such case will be negotiated separately, depending on the characteristics of each lease and the lessee's circumstances. Thus, in some instances, USGS may omit seams from the LMU reserves or permit the lessee to relinquish particular seams or lease areas that will not be mined.[45]

If a pre-FCLAA lessee requests designation of a section 5 LMU combining a pre-FCLAA lease with other Federal leases or non-Federal lands, the LMU criteria of section 5 also become applicable to the pre-FCLAA leases. Specifically:

1. the Secretary must find that maximum economic recovery of the coal deposits is served by consolidation;
2. all lands in the LMU must be under the effective control of a single operator, be able to be developed and operated as a single operation, and be contiguous;
3. the total acreage of the LMU must be 25,000 acres or less; and
4. any mining plans approved after the establishment of a section 5 LMU must require such diligent development, operation, and production that the reserves of the entire unit will be mined in a period of not more than 40 years.[46]

In addition, the terms of individual Federal leases in the LMU may be amended so that mining on any lease will be consistent with the requirements imposed on the entire LMU. LMU designation of a section 5 LMU is often to the lessee's advantage because the Secretary is authorized to provide that diligent development, continued operation and production occuring anywhere in the unit is considered as occurring on all Federal leases in the unit, thus, allowing a producing lessee to keep nonproducing Federal leases in the LMU after the 1986-91 diligence deadlines and to mine such leases in the optimum sequence for that mine. Designation also allows rental and royalty obligations for all leases in the LMU to be combined and advance royalties can be applied against the combined royalties due.

Many existing lessees will probably request LMU designations under section 5 in order to meet diligence; most of the lessees should qualify for such approval. Some operating lessees in Colorado and Utah have noncontiguous nonproducing leases that they intend to mine as part of their existing operations after the diligence date. Unless the requirement that all leases in the LMU be contiguous is modified or reinterpreted, a section 5 LMU could not include these noncontiguous areas and the lessee would probably shift production prematurely to the new area from other Federal leases.

Still other mines on Federal leases have very large reserves in multiple seams and could encounter the same difficulty in defining the LMU reserves for a section 5 LMU as described above for single lease LMUs. Reserves on some of these potential LMUs are so large that meeting the 2½ percent diligence production target could become a practical impossibility if all the lease reserves were included. These cases too will be addressed individually and could result in some seams being omitted from the LMU reserves or being relinquished.

Maximum Economic Recovery

Prior to enactment of the FCLAA in 1976, USGS conducted an informal monitoring program to ensure conservation of coal resources and prevent waste on Federal coal leases under the general authority of the Mineral Leasing Act to protect the public interest. Section 3 of FCLAA created a formal requirement for achieving the "maximum economic recovery" (MER) of Federal coal. The concept of MER "means that all portions of the coal deposits within the lease tract shall be mined that have a private incremental cost of recovery (including reclamation, safety and opportunity costs) less than or equal to the market value of the coal."[47] Beyond this general definition of the term MER, guidelines for determining what is required to meet MER have not been promulgated.[48]

FCLAA requires that MER be considered at three stages: 1) at the time the lease is issued; 2) when the mine plan is approved; and 3) on approval of a section 5 LMU. At the prelease stage, the USGS mining supervisor determines the mining method, e.g., surface, deep mining, etc., that is likely to yield the greatest recovery under given economic conditions. The prelease determination is based on a general examination of the tract and standard mining practices, and not a detailed seam-by-seam assessment. The premining assessment of MER, on the other hand, is expected to require a detailed investigation and the application of more specific engineering and economic evaluative criteria and may lead to modifications in the mine plan to ensure that MER is achieved. Before the Secretary can approve a petition for designation of a section 5 LMU combining one or more Federal leases with other Federal leases or with non-Federal reserves, he must find that the consolidation will serve maximum economic recovery of the coal resources.

Theoretically, the application of the MER requirement could lead to the extraction of marginal coal that was once left behind. The purpose of the MER standard was to prevent the possibility that operators on Federal leases would take only the most economically profitable coal seams and would leave the less profitable or marginal reserves in the ground. By requiring the lessee to average the costs of mining over all the economically recoverable coal under lease (thus offsetting the profit from mining high-grade reserves against the higher costs of taking marginal reserves) more coal is extracted, more royalties are paid, and less coal is rendered economically unrecoverable, Strict MER guidelines could result in larger estimates of LMU reserves, and therefore could affect the diligence and continuous development requirements for leases. MER determinations could also result in more complex mining plans, which would have a concomitant effect on the lessee's ability to comply with the time limits on diligent development. The nature of the MER concept makes it, in effect, a "continuing performance standard" that may require an operator to continue operating a Federal coal lease at marginal costs beyond the point where a lessee would cease mining in an unregulated operation.

The full extent of the impact of the concept of MER on Federal leases is unknown, since regulations implementing section 3 of the FCLAA have not yet been promulgated, and scope of its applicability to pre-FCLAA leases is uncertain.

Timeliness of Readjustment

Pre-FCLAA leases were originally subject to readjustment of lease terms at 20-year intervals. Section 6 of FCLAA reduced the readjustment period to 10 years. Consequently, when pre-FCLAA leases reach the end of their current 20-year term, each will be eligible for an extension of only 10 years. At readjustment, new lease provisions, including terms incorporating the requirements of the 1976 diligence regulations, are made part of the lease and the rentals and royalties are changed to conform to FCLAA. Current DOI practice is to set the new rental rate at $3.00/acre and the royalty rate at the statutory minimum of 12.5 percent of the sales price per ton for coal mined by surface methods, and at a lower discretionary rate of 8 percent for coal mined underground. For producing leases, the major impact of readjustment is financial—an increase in the royalty paid from (for example) $0.15/ton to perhaps $1.60/ton (assuming $20.00/ton for underground coal at eight percent). For undeveloped leases or leases in pending mine plans, if the diligence requirements are only effective on readjustment, the result would be differing diligence standards for pre-FCLAA leases. If diligence requirements for initiating production within 10 years are made effective only on readjustment, some lessees would still have to meet the 1986 deadline, while others, conceivably, would not have to produce until after the year 2000.

As a further complication, during the 1970's, many lease readjustments were delayed because of DOI personnel shortages and confusion over the applicability of various regulations due to litigation, legislation, and changes in the coal management program. At the end of fiscal year 1980, most of the backlog had been reduced and readjustments were pending for 40 pre-FCLAA leases.[49] A number of completed readjustments have been appealed to the DOI Board of Land Appeals and to the courts. Between January 1, 1981, and June 1, 1986, nearly 200 pre-FCLAA leases in the six Western Federal coal States are due for readjustment; another 191 of these leases are to be readjusted by June 1, 1991. At least 39 more pre-FCLAA leases will not be readjusted until after the 1991 diligence deadline (see table 78).

Table 78.—Readjustment Schedule for Pre-FCLAA Leases in Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming

State	Readjustments between Aug. 4, 1976 and June 1, 1986	Readjustments between June 1, 1986 and June 1, 1991	Readjustments after June 1, 1991
Colorado.	59	46	10
Montana. , ...	9	7	2
New Mexico.	18	9	1
North Dakota.	7	9	1
Utah	105	76	17
Wyoming	46	44	8
Total	244	191	39

Note Dates of readjustment obtained from Automated Coal Lease Data System. October 1980 The total readjustments do not include second readjustments of leases due to be readjusted after FCLAA (Aug. 4, 1976) or first readjustments of new leases issued after FCLAA

Because of these delays, some lessees have challenged DOI's right to readjust their leases. The lessees have argued that because DOI did not notify them of its intention to readjust their leases in a timely fashion before the expiration of the previous lease term, that DOI implicitly waived its opportunity to readjust their leases and that the leases continue for an additional term under the previous royalties and lease provisions. In some cases, this position may prevail depending on the specific facts, the anniversary date and the Department's actions relating to attempted readjustment. DOI has maintained that it has the authority to adjust leases even when the lessee was not notified on or before the 20-year anniversary date and to adjust leases with anniversary dates occurring before the passage of FCLAA to conform to the minimum royalties required by FCLAA. At least two Federal district courts have ruled against DOI on the issue; both cases have been appealed.[50] In the 1979 rulemaking for the new coal management program, the regulations governing readjustments were modified in response to industry comments. The regulations now provide that for leases which are subject to readjustment after June 1, 1980, if DOI does not notify the lessee before expiration of its present lease term of its intent to revise the lease, DOI will have waived its right to readjust the lease for the next lease term.[51]

Enforcement

The extent that diligence regulations are enforced will also influence their impact, Before promulgation of the regulations in 1976, DOI had not canceled any nonproducing leases. Before 1960 there had been little need for enforcing diligent development as most leases eventually went into production. However, in the 1960's, as coal production lagged while leased areage increased, the potential for using diligence requirements to stimulate development increased.

Before a pre-FCLAA lease is forfeited for not meeting diligence, a judgment must be obtained against the lessee. To do this, the Department of Justice must sue the lessee in Federal court at the request of the Secretary of the Interior. The decision to request enforcement action by the Justice Department is discretionary with the Interior Secretary, however, the final decision on whether or not to initiate a lawsuit is made by the Attorney General. It is likely that if DOI adopted an aggressive enforcement policy, the cases would be carefully chosen to establish a strong precedent, thus many weak or questionable cases could be deferred.

Under the Secretary's general discretionary authority to administer leases in the public interest, DOI can also waive violations of the Mineral Leasing Act and regulations either on its own initiative or through negotiations with the lessees. Generally, such waivers are not binding on DOI or the Government unless they are: 1) express, 2) written, and 3) executed by the appropriate official.[52]

Relinquishments

Some leases can be expected to relinquish their nonproducing leases voluntarily if they cannot meet diligence rather than go through court proceedings. Relinquishments must be found to be in the public interest.[53]

A significant factor affecting production potential from existing leases and the leases that are unlikely to meet diligence by 1986 is section 3 of the FCLAA that prohibits the issuance of new leases to lessees that have not produced commercial quantities from any existing leases they have held for 10 years by August 4, 1986.[54] This amendment to the Mineral Leasing Act creates a strong incentive to relinquish nonproducing leases if the lessee wishes to lease additional Federal coal reserves.

Potential Production From Federal Coal Leases and Diligence

In chapter 5 of this report, OTA presented the results of its comparison of the expected production from existing Federal leases with the minimum production levels required for diligence. This analysis, which assumed that the diligence requirements are fully applicable to existing leases, provides some indication of the situations that might arise.

By 1991, over 70 percent of the 502 leases in the six major Western Federal coal States could meet the existing diligence requirements.

- 216 leases with 7.4 billion tons of reserves are likely to meet diligence by 1986;
- 29 leases with 2.1 billion tons of reserves are likely to meet diligence by 1991 with extensions; and
- 112 leases with 3.4 billion tons of reserves are uncertain to meet diligence by 1991 with major uncertainties tied to delays in powerplant and transportation system construction, fluctuations in captive coal needs, and difficulties in defining the logical mining unit for leases with very large reserves in multiple seams.

Thirty percent of the Western Federal leases are unlikely to meet diligence by 1991 even with extensions:

- Production for 61 leases in the Kaiparowits Plateau with 1.4 billion tons of reserves is dependent on construction of a coal transportation system.
- Development of 10 leases in the Powder River basin with 1.4 billion tons of reserves are contingent on commercialization of synfuels technologies, such as in situ gasification, that can use lower quality reserves at the mine site.
- The remaining 74 leases are primarily small, scattered leases with poor quality reserves and are unlikely to be developed by 1991 even with extensions.

Most leases with potential for production by 1991 could qualify for extensions under existing guidelines. The exceptions are small-to medium-sized mines that are intended to serve spot markets and several underground mines opening in areas with difficult mining conditions requiring longer construction periods that do not fit clearly into any of the current guidelines.[55]

The 502 leases are divided into a total of 217 mine plans or blocks of contiguous leases; of these, 146 units could be producing by 1991 and many of these can be expected to request a section 5 LMU designation so that aggregate mine production can be used to meet diligence and with some exceptions should qualify as LMUs under current guidelines.

Exchanges

Exchange can be used to shift coal development on Federal or non-Federal lands away from areas where mining conflicts with other resource values or uses to more acceptable areas. Exchanges, thus can offset potential losses in coal production from environmental or land-use restrictions. Because of the requirement in section 2 of FCLAA that all new leases be awarded by competitive bidding, DOI has only a limited authority to offer unleased Federal coal in exchange for relinquishment of existing Federal leases or PRLAs in areas where mining poses environmental or other problems.

However, under general provisions of the Mineral Leasing Act, the Secretary can issue a noncoal mineral lease of comparable value, coal bidding rights, or modifications of up to 160 acres each to other coal leases in exchange for relinquishment of an existing coal lease or PRLA.[56]

Special legislation has been enacted specifically authorizing several proposed "lease swaps" involving existing Federal leases and PRLAs in Wyoming, Utah, and New Mexico and contested Indian leases and permits in Montana. Other existing Federal leases could qualify under the special alluvial valley floor exchange provisions in SMCRA.

Exchanges of Federal coal reserves for private coal lands have also been suggested. Under section 206 of FLPMA, DOI has the authority to exchange interests in Federal lands, including mineral rights, for interests in non-Federal lands of equal value if the exchange is determined to be in the public interest. Section 510(b)(5) of SMCRA directs the Secretary to establish a program of exchanges of non-Federal lands that cannot be mined because of alluvial valley floor restrictions for available Federal coal lands under section 206 of FLPMA.

According to information from OTA's State task forces, as much as 1.7 billion tons of Federal coal reserves are involved in various exchange proposals.[57] It is now apparent that not all of these exchanges will be completed, however, a significant portion of reserves that cannot be mined without substantial adverse social or environmental consequences could be replaced through the exchange mechanisms described below.

Special Exchange Legislation

Under special exchange legislation enacted by Congress, the Secretary of the Interior has been authorized to approve exchange relinquishments of certain existing leases and PRLAs and contested Indian leases and permits for new noncompetitive Federal coal leases. Generally, the Secretary must find that the exchange is in the public interest and that the value of the rights to be traded are approximately equal,

Public Law 95-554—Federal Coal Leasing Amendments Act of 1978

In the 95th Congress, DOI requested legislation giving it generic authority to exchange or condemn leases and PRLAs where mining poses environmental or other problems. Instead, Congress passed the Federal Coal Leasing Amendments Act of 1978 making minor amendments to the Mineral Leasing Act and specifically authorizing exchanges for all or part of nine leases underlying Interstate 90 and State highways near Gillette in northeastern Wyoming, and for eight PRLAs on the Kaiparowits Plateau in southwestern Utah.[58] The 1978 act also requested a feasibility study on the possible acquisition of private lands surrounding the Lake DeSmet Reservoir near Buffalo, Wyo., in exchange for Federal coal lands. The rights to be exchanged must be of approximately equal value, however, a cash settlement of up to 25 percent of the difference in value would be allowed.

DOI has completed the exchange studies under Public Law 95-554. In September 1979, it recommended against the Lake DeSmet exchange.[59] In June 1981, the Utah Power & Light exchange was rejected because the PRLAs to be exchanged were determined to be not of approximately equal value to the new lease tracts requested.[60] The Wyoming highway exchanges are proceeding and negotiations with the lessees are continuing on the leased areas to be relinquished in return for other Federal coal reserves.[61]

New Mexico Lease Exchange

Public Law 96-475[62] directs the Secretary of the Interior to issue leases for coal on other Federal land in exchange for all or portions of two Federal leases in the Bisti area of New Mexico. The exchange is to be completed within 30 months, i.e., by April 1983, or as expeditiously as possible. The Bisti lease area covers about 1,360 acres of the Bisti wilderness study area, as well as other areas with unusual paleontological, archaeological and recreational values.[63] The legislation specifically describes the unleased Federal coal lands that are to be offered in the exchange.

The exchange is to be made pursuant to the existing land use policies and leasing procedures established by the Secretary. The leases issued must contain the same terms and conditions as leases surrendered. The two leases are due to be readjusted before the exchange date and would thus be subject to post-FCLAA requirements.

The exchange involves two leases in the planned Bisti Mine. The lessee, Western Coal Co. had sought the exchange and agreed to defer exploration and mine construction activities in the areas pending administrative and legislative action. Processing of the exchange is not expected to delay development on the other Federal leases in the mine area.

Northern Cheyenne Indian Reservation Lease Exchange

Public Law 96-401 authorizes the Secretary of the Interior to negotiate for the cancellation of seven leases and 11 prospecting permits on Indian lands on the Northern Cheyenne Reservation in Montana.[64] The tribe has been contesting the BIA's issuance of these coal development rights covering over half of the tribal reservation. Development of the leases and permits was suspended by the Secretary of the Interior in response to the tribe's petition. The act would allow the Secretary to negotiate with the lessees and permit holders for cancellation of their rights in exchange for bypass leases on Federal coal adjacent to their active mines and for Federal coal bidding rights equal to the amounts that they have invested in the Indian coal rights. The act does not provide for a ton-for-ton or acre-for-acre exchange of Federal coal lands for the disputed tribal coal lands, but rather establishes a framework for the parties to negotiate a settlement and for the coal companies to recover their out-of-pocket expenses. The settlement authority in the act does not affect any legal rights that the parties may have. If they are unable to reach an agreement, the issues could still be litigated.[65]

Alluvial Valley Floor Exchanges

Section 510(b)(5) of the Surface Mining Control and Reclamation Act of 1977 requires that reserves on certain nonproducing Federal leases and private lands in alluvial valley floors with agricultural potential that cannot be mined, can be exchanged for Federal coal if the lessee made substantial legal or financial commitments to developing a mine before January, 1, 1977.[66] It is not yet known how much, if any, coal in alluvial valley floors will be exchanged under this provision intended to compensate mine owners and lessees who do not qualify for permit approval under the grandfather provisions of section 510(b)(5). In general, relatively small amounts of Federal lease reserves are likely to be affected by the prohibition on mining agriculturally important alluvial valley floors and the Federal reserves that would be eligible for exchange would be even smaller. (See the discussion of alluvial valley floors in ch. 10 of this report.)

Section 510(b)(5) also directs the Secretary to establish an exchange program under section 206 of FLPMA to trade title to available Federal coal lands for title to private lands that cannot be mined because of alluvial valley floors. This exchange of private lands for Federal reserves is mandatory and not subject to the requirement of previous substantial legal and financial investment.[67] There are a number of mines in the Powder River basin, with substantial reserves of non-Federal coal under alluvial valley floors that might qualify for these mandatory exchanges.

If significant amounts of reserves from these mines qualify, the net result could be a decrease in available unleased Federal reserves because of the transfers of Federal coal to non-Federal ownership in exchange for unminable non-Federal reserves in alluvial valley floors.

Other Exchanges

Under section 206 of FLPMA, DOI can exchange interests in Federal lands, including mineral rights, for interests in non-Federal lands of equal value if the public interest is well served by the exchange.[68] Cash settlement of up to 25 percent of the difference in value of the tracts exchanged is authorized. The alluvial valley floor coal exchanges are to be evaluated under this provision. Several exchanges of non-Federal coal lands for Federal coal lands have been suggested to preserve important wildlife habitat from mining, or to allow "blocking up" of checkerboard lands or other areas of dispersed mineral ownership so that both the Federal Government and the private owner receive title to contiguous LMUs as a result.[69] Exchanges of lands found unsuitable for mining under SMCRA have also been suggested; however, exchange of any Federal lease areas could only be accomplished by specific legislation.

DOI's limited experience with trying to implement the authorized exchanges discussed earlier has revealed technical and administrative difficulties involved in working out an exchange agreement acceptable to both parties. The difficulties in determining an appropriate value for the rights to be exchanged have been particularly troublesome in Utah and Wyoming where the reserves to be relinquished are of lower present economic value than the reserves sought in exchange. Even so, other leaseholders with reserves that cannot be mined can be expected to press for exchanges through administrative, legislative and judicial channels. Although all the coal reserves under existing leases may not be mined, the eventual result of exchanges could be little net change in the total amount of Federal coal reserves developed. The location of mining may change compared to present patterns of Federal lease ownership, but the amount of Federal reserves committed by past leasing practices could remain essentially the same.

Preference Right Lease Applications

Under section 2(b) of the 1920 Mineral Lands Leasing Act, prospecting permits could be issued for areas where commercial deposits of coal were unknown. The purpose of this provision, similar to prospecting permit provisions for other leasable minerals and to the location patent system under the mining law, was to encourage the exploration and development of mineral resources on public lands.[70] A successful prospector, upon showing discovery of a valuable deposit during the term of the permit, was entitled to a noncompetitive preference right lease. About half of the existing Federal coal leases were issued through the preference right lease mechanism .7' Section 4 of the FCLAA repealed the authority to issue preference right leases except for PRLAs and prospecting permits pending on the date of its enactment.[72]

Potential Production From PRLAs

As of March 1981, there were 171 actively pending PRLAs covering over 395,000 acres and containing over 5,7 billion tons of recoverable reserves. OTA estimates that the potential production from these PRLAs is between 35 million and 60 million tons per year depending on how the various legal and environmental problems affecting certain PRLAs are resolved.[73] About 10 million tons of this annual production is associated with new mines on existing Federal leases in Colorado and New Mexico. This estimate is lower than the earlier DOI estimates of 186 million to 248 million tons per year used in development of the new coal management program and reflects: 1) a reduction in DOI's estimates of in-place reserves; and 2) OTA's analysis of the production potential of PRLAs in Wyoming, Colorado, and New Mexico. Even the lower production estimates for PRLAs indicate a significant potential for contributing to coal supply in 1990-95.[74]

The potential impact of the various legal, planning, and environmental restrictions on PRLA issuance and hence production was probably overestimated in the DOI review. OTA's examination of the data used in preparation of the working paper disclosed that most of the environmental restrictions were related to wildlife concerns and would probably result in special lease stipulations on impact mitigation rather than in deletion of reserves from the PRLA. The legal problems include some, such as incomplete applications, that are curable during the adjudication process under regulations allowing the applicant an opportunity to submit additional data.[75] Other legal problems such as failure to submit any information about the quantity and quality of reserves discovered probably would result in rejection, however, only a few applications did not contain this information, so the probable impact is small.[76]

The true potential production from PRLAs will not be known until after the pending applications have been processed and those that meet the legal requirements have been issued. With few exceptions, processing of the pending PRLAs was suspended during most of the past decade: first, because of the 1971 moratorium; then, to allow for development of new leasing policies; and, finally, by litigation.[77] Following promulgation of final regulations for the new coal management program in July 1979, processing of pending PRLAs was resumed. Under current policy, all PRLAs should be adjudicated and leases issued to qualified applicants by 1984.

Many of the legal, administrative, and procedural issues related to the issuance or rejections of PRLAs have been addressed by DOI and the courts, however, a number of new questions are likely to arise as the applications are processed and these must be resolved before the full production from PRLAs will be realized.

Procedures for Processing PRLAs

Before its repeal in the 1976 amendments, section 2(b) of the Mineral Leasing Act of 1920 provided:

> Where prospecting or exploratory work is necessary to determine the existence or workability of coal deposits in any unclaimed, undeveloped area, the Secretary of the Interior may issue, to applicants qualified under this chapter, prospecting permits for a term of two years, for not exceeding five thousand one hundred and twenty acres; and if within said period of two years thereafter the permittee shows to the Secretary that the lands contain coal in commercial quantities, the permittee shall be entitled to a lease under this chapter for all or part of the land in his permit.

A prospecting permit could be extended for 2 years; however, the approval of extensions was discretionary. In practice, they appear to have been granted routinely at the request of the permittee. In order to qualify for a preference right lease, the prospector had to submit an application accompanied by evidence showing the discovery of commercial quantities of coal within the permit area before the expiration date of the permit. The 1976 repeal was subject to valid existing rights, thus any pending permits or applications for preference right leases were not affected and could be pursued under pre-FCLAA requirements. Any leases issued would, however, be governed by new lease terms imposed by FCLAA.

As a result of an internal review of DOI procedures and criteria for issuing prospecting permits and approving PRLAs, new regulations were issued in May 1976 governing all pending and future PRLAs.[78] The regulations formally defined the standards for determining "commercial quantities" under the Mineral Leasing Act, specified the information to be submitted, and established a two-phase adjudication procedure, The internal review had disclosed that, in some instances, the less stringent "workability" standard had been used mistakenly to determine whether a PRLA should be issued rather than the stricter "prudent person" test.[79] The regulations formally adopted the "prudent person" standard applied under the Mining Law as the appropriate test for determining discovery of commercial quantities of coal under the Mineral Leasing Act.

The commercial quantities standard requires that "the coal deposit discovered . . . shall be of such character and quantity that a prudent person would be justified in further expedition of his labor and means with a reasonable prospect of success in developing a valuable mine. " The applicant must present "sufficient evidence to show that there is a reasonable expectation that revenues from the sale of the coal shall exceed the cost of developing the mine and extracting, removing, transporting, and marketing the coal. " Mining costs include expenses for environmental protection, reclamation, and compliance with applicable State and Federal laws and regulations.[80]

Under the new adjudication procedure, the application was to be accompanied by an "initial showing" with reserves estimates and supporting geologic data, maps, and a description of the proposed mining operation. Holders of pending PRLAs were notified to supplement their applications with the required initial showing. (Table 79 shows the adjudication steps in processing PRLAs.) The application and initial showing are first examined for completeness and compliance with other Mineral Leasing Act requirements. Incomplete or insufficient applications can be rejected at this stage, however in many instances, the applicant will be given an opportunity to supplement or correct the missing data. If the PRLA is rejected then or later in the process, the decision can be appealed administratively to the Interior Board of Land Appeals.[81]

The initial showing is followed by a technical examination and environmental assessment from which proposed lease terms and stipulations are formulated. This review will normally be conducted during the ongoing BLM land use planning cycle established by each State BLM Office, unless the lessee requests an accelerated review. The environmental assessment includes a site-specific analysis to evaluate the suitability of the area for mining and to develop appropriate lease stipulations, consultation with State government, and preparation of either an environmental assessment (EA) document or an EIS as required under NEPA. The Geological Survey reviews the adequacy of the initial showing and recommends lease terms and conditions and bonding, MER, and minimum production requirements for diligence.

The applicant is then provided with the proposed lease terms and stipulations (including rentals and royalties), the EA or EIS, and other relevant information and allowed 90 days to submit a "final showing" of commercial quantities. The final showing must include the applicant's estimated production, estimated revenues, and mining and reclamation costs. The estimates must have a reasonable factual basis and reflect all costs that a prudent person would consider before deciding to develop a mine. It must demonstrate that the deposit can be profitably mined and marketed under the proposed lease terms and applicable State and Federal laws. If all the requirements of the final showing are satisfactorily met, the applicant is entitled to a lease.

Litigation Involving PRLAs

NRDC v. Berklund

In March 1975, the Natural Resources Defense Council and the Environmental Defense Fund sued DOI seeking: 1) a declaratory judgment that the Secretary had the discretionary authority to refuse to issue a PRLA on environmental grounds under the Mineral Leasing Act of 1920 and National Environmental Policy Act of 1969, and that an environmental

Table 79.—Processing Preference Right Lease Applications

Review of application and initial showing	
1. Review completeness and adequacy of application.	**Reject PRLA** for failure to meet MLA requirements if: —Not filed before prospecting permit expired; —Not signed by qualified applicant; —Advance rental not paid; or —Evidence of discovery of commercial quantities not submitted.
2. Review completeness of initial showing.	**Reject PRLA** if: —Initial showing not filed; or —Initial showing not timely filed.
3. Determine whether PRLA conflicts with valid mining claims.	Delete areas covered by valid mining claims located before Multiple Mineral Development Act (1954) and the date prospecting permit was issued. (Claims must be filed with BLM as required by FLPMA to be presumed valid); notify applicant of conflict and of procedures for contesting validity of adverse mining claims.
4. Request additional information needed for initial showing and mining claims reviews.	
5. Determine adequacy of initial showing.	**Reject PRLA** if: —Initial showing fails to show any coal or such limited reserves or low quality coal that mining could not be expected to take place; or —After deletion of mining claims, initial showing fails to show sufficient reserves remaining to sustain proposed commercial development. **Accept initial** *showing* if all requirements are met; refer application for technical review and environmental assessment.
Technical review and environmental assessment	
1. Establish priority for review of PRLA in land use planning process.	Schedule accelerated review on applicant request.
2. Conduct environmental analysis including unsuitability criteria.	Prepare environmental assessment (EA) or draft environmental impact statement (EIS).
3. Review adequacy of EA or EIS; consult with Governor, Surface Management Agency, other agencies, and public. Issue final EAIEIS.	Request comments on adequacy of EAIEIS, proposed lease terms, stipulations. Hold public hearing. Prepare final EA/EIS.
4. Set proposed lease terms, conditions, rental, royalties, bonding, MER, and minimum production requirements.	
5. Request applicant to submit "final showing" of commercial quantities.	
Review of final showing	
1. Determine completeness of final showing.	**Reject PRLA** if applicant fails to submit final showing. Request additional information needed for final showing.
2. Determine whether applicant meets commercial quantities test.	Has applicant demonstrated discovery of a coal deposit of such character and quality that a prudent person would be justified in further expenditure of his labor and means with a reasonable prospect of success in developing a valuable mine with a reasonable expectation that the revenues from the sale of the coal will exceed the costs of developing the mine **and** extracting, removing, transporting, and marketing the coal? (NOTE: Applicant may delete areas that are recommended as unsuitable for mining from application before final showing to exclude costs of mining these areas.)
3. Issue final decision on PRLA.	**Accept PRLA and issue lease** if applicant meets all requirements and commercial quantities test. **Reject PRLA** if applicant does not meet commercial quantities test on final showing. *Negotiate* with applicant for exchange of PRLAs that meet commercial quantities test but pose environmental or other problems if developed.

SOURCE. Bureau of Land Management, Instruction Memorandum 79-846 (revised), Solicitor's Opinion M-36893, as revised, Jan. 8, 1981.

impact statement must be prepared before issuance of any PRLA that involved a "major Federal action significantly affecting the environment;" and z) an injunction barring the issuance of any such leases without complying with the declaratory judgment provisions sought.

In June 1978, the District Court of the District of Columbia held: 1) that the Secretary has no discretion to reject a PRLA if the applicant successfully meets the commercial quantities test and other requirements of the Mineral Leasing Act; and 2) that NEPA requires the preparation of an EIS before the issuance of any lease where such action is "a major Federal action significantly affecting the environment."[82]

In reaching its decision the court further noted that NEPA requires the Secretary to "exercise his authority to safeguard society and prevent irreparable damage to the environment through a careful and complete formulation of lease terms."[83] The court observed that the Secretary has broad powers to establish strict standards for proposed lease terms that could make compliance with the commercial quantities test difficult or impossible (i.e., the cost of implementing these terms would make the mining costs exceed the market value of the coal). Thus, while DOI cannot deny a PRLA solely for failure to meet environmental requirements, the court stated that "if a permittee does not have the technological capability to comply with (strict environmental) standards, the high cost of compliance will outweigh potential coal revenues and he will fail the commercial quantities test, "[84]

In preparing an EIS prior to the issuance of a PRLA, the Berklund court ruled that the Secretary must consider at least three alternatives: 1) exchange of the PRLA for a mineral lease of comparable value or coal bidding rights;[85] 2) issuance of the lease with lease terms to protect against irreparable damage to the environment as required by NEPA, which will determine whether the permittee will meet the commercial quantities test, which in turn will determine whether the lease will be issued; and 3) if the applicant will not agree to an exchange and the lease terms do not defeat the commercial quantities showing, withdrawing the lands or asking Congress for legislation canceling the lease on payment of just compensation.[86]

By clear implication, the decision upheld the application of the 1976 commercial quantities regulations. The decision was affirmed by the U.S. Court of Appeals in November, 1979.[87]

Utah International Inc. v. Andrus (Utah)[88]

Utah International, Inc., sued DOI seeking a judgment that the May 1976 PRLA adjudication procedures and commercial quantities regulations could not be applied to its southern Utah PRLA which was filed before they were effective and also seeking to have court rule that any lease issued from its PRLA would have lease terms in effect on date of application rather than post-FCLAA requirements. The Utah Federal district court held that the 1976 regulations were proper and could be made applicable to pending PRLAs; and that an applicant does not acquire a vested right to a lease or to have its application judged under a particular standard simply by filing an application. The court further ruled that an applicant could not sue over the application of the commercial quantities test to its PRLA until after DOI had made a final decision approving or rejecting the application and the applicant had all exhausted administrative appeals in DOI.

Utah International *Inc. v.* Andrus (Colorado)[89]

Utah International, Inc., also sued DOI over processing of a PRLA in Colorado—this time with more success. The Colorado Federal district court decision cited the result in the Utah case with approval, noting that it is within the authority of the Secretary to act to correct errors in the administration of programs committed to his discretion, thus it was proper to issue new regulations for processing PRLAs and to establish a corrected commercial quantities test fully applicable to pending applications, The Colorado court then distinguished the PRLA in the case before it from other PRLAs by finding that DOI had made a final and binding determination of discovery of commercial quantities on the PRLA in 1970 before the effective date of the new regulations. Having made a final decision, DOI could not subsequently reopen the case to apply its later requirements. DOI was ordered to process the application. The court further held that the applicant, Utah International, was not entitled to the lease terms in effect when its application was approved, but rather the Secretary had full discretion to set the terms and conditions of the lease. The case was appealed by both DOI and the plaintiff, Utah International. Its value as precedent for other PRLAs is limited since the decision was based on the specific circumstances of the case.

Other Legal and Administrative Issues Related to PRLAs

Unclaimed Land

Under the 1920 Act, prospecting permits and preference right leases could be issued only on "unclaimed, undeveloped" lands. A 1977 Solicitor's Opinion (Solicitor's Opinion No. M-36893), interpreting the meaning of "claimed" as any land on which a valid mining claim had been filed under the Mining Law of 1872 and was present at the time the prospecting permit was issued, raised the prospect that many pending PRLAs would be invalid in those areas in which they overlapped mining claims.

In response to the Opinion, in August 1977, PRLA holders were asked to submit a "certified abstract of title" within 160 days listing previous mining claims affecting land within their PRLAs.[90] A review of the submitted abstracts revealed that lands encompassed by 20 PRLAs were covered in part or in whole by a total of 465 mining claims that had been issued prior to the coal prospecting permits. Most of these PRLAs are in Wyoming, where 14 out of 72 applications, covering 25,586 acres include one or more mining claims. One application had 239 mining claims. Most of these claims are for uranium minerals.

On November 19, 1979, the Solicitor issued a Supplemental Opinion on the effect of the August 1977 Opinion on the processing of pending PRLAs. The Supplemental Opinion concluded that prospecting permits previously issued in "claimed" or "developed" areas are void and clarified the meaning of the terms "unclaimed" and "undeveloped" under the Mineral Leasing Act. The term "unclaimed" refers to the absence of valid mining claims. The term "undeveloped" means the lack of surface mineral activities associated with the delineation of an ore body or mineral resource which could reasonably be expected to disclose knowledge of an area's coal or phosphate potential. The Supplemental Opinion also noted that holders of PRLAs "have an opportunity through private contests, submission of evidence of an area's status, or by rebutting a show cause order, to show that the lands under application were 'unclaimed, undeveloped' at the time of prospecting permit issuance."[91]

Review of the Solicitor's Opinion on unclaimed areas resulted in a third opinion issued January 8, 1981. This third opinion concluded that only claims filed before enactment of the Multiple Mineral Development Act of 1954 could adversely affect PRLAs, The opinion further concluded that it is sufficient to only check BLM land office records for evidence of mining claims thus allowing DOI to dispense with the requirement for certified abstracts.

The results of this third Solicitor's Opinion on the "unclaimed, undeveloped" issue could make processing of PRLAs simpler and could result in some PRLAs being approved although they might contain conflicting mining claims for other minerals. The Multiple Mineral Development Act of 1954 provides that mining claims located after the date of its passage do not carry with them the right to leasable minerals, including coal.[92] Thus, location of a mining claim after that date does not create a claim that is adverse to the rights of a coal lessee and, in fact, the Government may lease the coal, phosphate, oil, and gas, and other leasable minerals on these lands. The PRLA records examined by OTA do not indicate when the mining claims that potentially conflict with the PRLAs were filed. However, it is likely that many of the uranium claims were located after the passage of the 1954 Act and thus could not result in a conflict with any coal prospecting permits.

The elimination of the requirement for submission of certified abstracts makes use of provisions of the Federal Land Policy and Management Act of 1976. Section 314 of FLPMA requires that holders of unpatented mining claims file information on the location of their claim and an affidavit of assessment work performed with the BLM by October 21, 1979, and annually thereafter.[93] Failure to file this information is deemed conclusively to constitute abandonment of the claim. Before this provision was enacted, there often was no feasible procedure available to BLM or the prospector to determine the presence of mining claims on lands covered by applications for prospecting permits.

If the third Solicitor's Opinion is implemented, the portions of a PRLA covered by valid prior claims will be deleted from lease consideration. This would reduce the lease acreage of some PRLAs and perhaps completely disqualify others. In Wyoming, PRLAs with mining claims contain over 600 million tons of reserves, and 15.5 million tons out of 20,5 million tons potential production capacity from PRLAs could be affected by these claims. Whether issuance of a preference right lease is affected by the presence of mining claims depends on: 1) how much of the PRLA is covered by claims; 2) whether the claims were filed before 1954; 3) whether the claims have been kept valid through the required work requirements at least up to the time the prospecting permit was issued; and 4) whether the mining claim holder has made the required filing with BLM.

Existence and Workability of Coal Deposits

Preference right leases were awarded only for those lands where commercially valuable coal deposits were not known to occur. Prospecting permits were issued under the Mineral Leasing Act of 1920 where prospecting or exploratory work was necessary to determine the existence or "workability" of coal deposits. If the permittee could show that land contained in coal in "commercial quantities, " the permittee was entitled to a preference right lease for the vacant, unappropriated lands described in the prospecting permit.

The concept of workability for coal preference right leases is similar to the "valuable deposit test" that applies to other minerals and is the same as the commercial quantities test in the current coal regulations.{" To qualify, the land must be found to contain "coal of such quantity and quality as would warrant a prudent coal miner or operator in the expenditure and labor incident to the opening and operation of a coal mine or mines on a commercial basis."[95] In other words, "a permittee must have found a deposit upon which a prudent man would expend his labor and means (a workable deposit) and that to meet this test, commercial quantities of coal must be found. "

In deciding whether a prospecting permit could be issued, USGS also used a classification standard of workability that assumed that the coal deposits were marketable and which focused on whether the known physical characteristics of the coal deposits indicated that the value of the coal was greater than the costs of extraction. This less stringent classification standard of workability was for some years mistakenly used to determine whether a permittee was entitled to a lease.[96] This misunderstanding was corrected by DOI in the 1976 commercial quantities regulations. This confusion over the correct application of the workability test raised questions about whether some lands had correctly been open to prospecting.

Some environmental groups have argued that some prospecting permits in Wyoming were issued on lands with abandoned underground mine workings or surface coal outcrops and that such lands should have been classified as areas with known coal deposits. Issuance of prospecting permits in such areas would violate the statutory requirement that known deposits must be leased competitively.[97] However, in 1979 in rulemaking for the new coal management program, DOI rejected a proposal to reexamine PRLAs for errors in determining the presence of known deposits. 1)01 "will continue to give these determinations a presumption of administrative regularity;" however, "if a case file does not contain the required conclusion by USGS that a prospecting permit could be issued then the presumption of administrative regularity does not apply," and DOI "will examine in such a case whether the permit was properly granted."[98]

Unsuitability for Mining

Pre-FCLAA leases can be affected in two ways by current requirements and procedures relating to the environmental unsuitability of lands for coal mining: 1) under sections 510 and 516 of the Surface Mining Control and Reclamation Act of 1977, performance criteria for mining must be considered before a mine plan is approved, and if the impacts cannot be mitigated the plan may be rejected; 2) mining on a pre-FCLAA lease may be foreclosed if it is within an area that is designated unsuitable for mining as a result of the petition process established in section 522(a) of SMCRA.[99]

BLM land use plans and coal lease tract selection include the consideration of suitability criteria for the medium and high potential coal lands in each BLM district planning area. Lands that are not unsuitable are considered further in the land use planning and coal leasing process. Suitability criteria are also applied by OSM to each nonproducing pre-FCLAA lease when a mining and reclamation plan is submitted. Before permit approval OSM consults BLM for special stipulations or recommendations on the suitability of leased areas for the proposed mining operation. The impact on pre-FCLAA leases has been relatively small, although the status of several hundred million tons of reserves in the Powder River basin potentially could be affected by alluvial valley floor restrictions (see ch. 10 for further discussion). Overall, the impacts of unsuitability criteria and the designation of lands unsuitable for mining are not are not expected to impair the ability of existing Federal leases to meet the possible range of demand for Western coal in the next 10 to 15 years.

Federal lands unsuitability criteria have two major sources: First, an order issued by President Carter in May 1977 directing the Secretary of the Interior to lease coal only in areas "where mining is environmentally acceptable and compatible with other land uses" and to review existing leases for compatibility with these standards, and to take the necessary steps under existing law to deal with nonproducing, environmentally unsatisfactory leases and applications.

Second, the Surface Mining Control and Reclamation Act of 1977 (SMCRA) requires the Secretary of the Interior to review all Federal lands to identify any areas unsuitable for surface coal mining operations. Standards of unsuitability in section 522 of SMCRA focus on environmentally sensitive areas or areas which are classified for other uses, such as national parks or wilderness areas. Other Federal statutes impose additional responsibility on the Federal Government to protect endangered species, historic and culturally significant sites, etc.; these were also included in the suitability criteria. The unsuitability review includes a process for public participation that considers matters of local or State significance and a procedure for private surface owners to withhold consent for new Federal coal leases.

Under the July 1979 coal management regulations, unsuitability criteria for new coal leases are applied during the land use planning process in order to identify those areas requiring special stipulations to provide necessary protection from adverse impacts of mining. These criteria apply to all surface minable areas and also to underground mines if mining would unduly disturb the surface, cause subsidence or interfere with surface occupancy. Exceptions to these criteria are permitted to protect valid existing rights or substantial legal and financial commitments made by operators before enactment of SMCRA. In some instances, the criteria extend to buffer zones around protected areas, such as those listed in the National Register of Historic Places, endangered species habitats and lands with National Resource Waters on site. Section 522 criteria also apply to mine plans; if sufficient data are not available to determine the minability at the time of leasing, the issue will be resolved at the mine plan approval stage.

Designation of Lands Unsuitable for Mining: Section 522(a) of SMCRA establishes a procedure for petitions to designate lands unsuitable for mining. An unsuitability designation is mandatory if required reclamation is not technically or economically feasible. SMRCA also provides for Federal or State agencies to designate land unsuitable for mining as a matter of discretion based on a review of the petition if:

1. mining is incompatible with existing State or local land use plans;
2. mining could result in significant damage to important historic, cultural, scientific and esthetic values and natural systems on fragile or historic lands;
3. mining of renewable resource lands results in substantial loss or reduction of long-range productivity of food or fiber products and water supply; and
4. mining of natural hazard lands (such as areas subject to frequent flooding and areas of unstable geology) could substantially endanger life and property.[100]

The petition process forces consideration of the cumulative environmental impacts of surface mining that may be overlooked or inadequately analyzed in the application of unsuitability criteria during individual mine plan review. It also allows examination of environmental issues that are not specifically addressed in requirements for mine plan review, such as the impacts of mining on national parks.

By June 1981, two petitions had been filed in the West to designate lands unsuitable for mining; one in the Alton area of southwestern Utah and the other in the Tongue River Valley of southeastern Montana.

The Alton Petition

On November 28, 1979, the Environmental Defense Fund, Friends of the Earth, Sierra Club, and seven residents of the Alton area in southwestern Utah petitioned the Secretary of the Interior to designate certain Federal lands near Bryce Canyon National Park and Dixie National Forest as unsuitable for surface coal mining, Approximately 325,200 acres, or slightly more than 500 square miles, were affected, including 29 Federal leases covering over 26,000 acres containing about 290 million tons of surface minable coal reserves, 100 million tons of recoverable underground reserves, and two PRLAs covering 2,398 acres. The major allegations in the petition dealt with the technological and economic feasibility of reclamation, potential damage to surface and ground water systems and potential damage to the unique values of the park and national forest.

The final EIS on the petition, issued by OSM in November 1980, did not support the claims that: 1) the Alton land could not be reclaimed; 2) blasting from mining would damage geologic formations; 3) wildlife would be threatened; and 4) mining would cause irreparable damage to water supplies. It did note that these issues would be reexamined as part of the permit approval process and that appropriate stipulations could be required should additional information reveal any such adverse problems. The EIS did find that mining in part of the area would impair scenic vistas from Bryce Canyon National Park and that high noise levels would occur in some areas within the park. In December 1980, the Secretary of the Interior declared 9,049 acres containing approximately 24 million tons of coal near Yovimpa Point in Bryce Canyon National Park as unsuitable for mining because of the adverse impacts on the

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park. The decision stated that mining activities would significantly reduce visibility and scenic vistas from the park overlooks and would raise noise levels thus damaging the values for which the park was established and diminishing the experiences of the park visitors. In support of his decision, Secretary Andrus also cited his responsibility as the steward of the national parks "to conserve the scenery and the natural and historic objects and the wildlife therein and to provide for the enjoyment of the same in such manner and by such means as will leave them unimpaired for the enjoyment of future generations."[101]

The decision left the two main leaseholders in the petition area, Utah International and Nevada Electric Investment Co. approximately 16,700 acres under lease containing 266 million tons of coal to supply the proposed Allen-Warner Valley Energy System or other projects.

Utah International challenged the decision in Federal court alleging that its leases should be exempt from unsuitability designation because of substantial legal and financial commitments undertaken by the lessees before SMCRA was enacted. The petitioners, the Environmental Defense Fund (EDF), also appealed the decision, alleging that the Secretary failed to consider adequately the effects mining would have on the national park and on the regional water supply. If EDF's suit results in expanding the area unsuitable for mining, there could be a significant impact on coal production from the area. Up to now, however, the potential for coal production from the leases in the area has not been significantly impaired even though 12 of the 29 leases in the area are affected, in whole or in part, by the Secretary's decision. The impact of the decision is probably limited to its unique circumstances since few, if any, other existing leases border on national parks. 102

The Tongue River Petition

In November 1980, the Northern Plains Resource Council and three of its affiliates, the Tri-County Ranchers Association, the Rosebud Protective Association and the Tongue River Agricultural Protective Association filed a petition with the Montana Department of State Land and OSM to designate approximately 100 thousand acres of intermingled Federal, private, and State lands in the Tongue River Valley in southeastern Montana unsuitable for surface mining. The major allegations in the petition are that thin topsoils and indigenous salts make reclamation technologically and economically unfeasible, and that strip mining could damage water supplies and the long-term productivity of farmlands. The area in the petition includes an estimated 10 billion tons of strippable coal and includes the proposed non-Federal Montco Mine that has a projected production capacity of 12 million tons per year by 1990. Substantial amounts of Federal coal are located in the area, but there is no currently leased Federal coal in the area, so the petition will not have any significant impact on the development of existing Federal leases in Montana. The petition was found to be complete and the allegations are now under review by the State of Montana and DOI,[103] Final decision on non-Federal lands rests with the State; the decision of Federal lands suitability will be made by DOI. A decision on the petition will be made by December 29, 1981.

Footnotes for Chapter 9

[1]For a description of the public land disposal laws and the origin of split ownership problems in the West, see Management of Fuel and Nonfuel Minerals in Federal Lands, Office of Technology Assessment (OTA-M-88), April 1979, p. 86,

[2]30 U.S.C. 1304, SMCRA narrowly defines the surface owners to which the consent requirement applies. A ''qualified surface owner" is a natural person (or a corporation controlled by a natural person) who: 1) owns legal or equitable title to the land surface, and 2) either lives on the land or personally farms the land or derives a substantial portion of his income from such farming or ranching operation, and 3) has met the previous conditions for 3 years before granting consent.

[3]See discussion of Coal Lands Act in Management of Fuel and Nonfuel Minerals in Federal Lands, supra note 1, pp. 86-89.

[4]Act of Feb. 25, 1920,41 Stat. 438.

[5]G. Bennethum. Holdings and Development of Federal Coal Leases (Washington, D, C.: Bureau of Land Management, 1970). There was four times as much coal acreage under lease in 1970 than there was in 1960. See chs. 3 and 13 of this report for history and extent of coal leasing from 1950 to 1980.

‘Secretarial Order No, 2952, Feb. 13, 1973.

‘Two reports that were widely quoted in these hearings were: J. Cannon, Leased and Lost; A Study of Public and Indian Coal Leasing in the West [New York: Council on Economic Priorities, 1974), and U.S. General Accounting Office, Improvements Needed in Administration of Federal Coal Leasing Program, 1972.

[8]Federal Coal Leasing Amendments Act of 1976, Public Law 94-377, 90 Stat. 1083, Aug. 4, 1976. In 1976, the House of Representatives approved S. 39 I by a vote of 344-51, and the Senate accepted the House amendments by unanimous vote. President Ford vetoed the bill on July 3, 1976. [Weekly Compilation of Presidential Documents, vol. 12, July 3, 1976.) The Congress overrode the President’s veto. The Senate vote was 76-17, 122 Cong. Rec. 25198, at 25465 (Aug. 3, 1976); the House of Representatives was 315-86, 122 Cong. Rec. H831O-H832O (Aug. 4, 1976).

[9]The Draft Environmental Impact Statement on the Proposed Federal Coal Leasing Program issued by DOI in 1974 proposed an “Energy Minerals Allocation Recommendation System” in which leasing would be based on a Federal coal allocation model. The Final Environmental Statement on the Proposed Federal Coal Leasing Program issued in 1975 described a different system, the “Energy Minerals Activity Recommendation System, ” described above. Since both systems have the same acronym, they have sometimes been referred to as “EMARS I“ and "EMARS II. ”

[10]NRDC v. Hughes, 437 F. Supp, 981 (D.D.C. 1977]; order modified, 454 F. Supp. 149, 1978,

[11]See 437 F. Supp. 981,993.

[12]Specifically the settlement authorized leasing in four circumstances: “bypass,” i.e., leases in which Federal coal might otherwise be lost if not developed by an existing mine; hardship (involving seven named lease applications); employment (leases issued to maintain production and employment in mines existing on Sept. 29, 1977); and leases for certain experimental DOE projects (i.e., projects authorized under sec. 908 of SMCRA 30, USC 1328 to conduct and promote research, experiments and demonstration projects relating to alternative coal mining technologies). Exchanges of Federal leases in alluvial valley floors under sec. 510(b)(5) (30 U.S. C. 1260(b)(5]) of SMCRA were also allowed. The Order expired before the PRLAs were processed and adjudication of these applications is being conducted under new coal management regulations issued in 1979. See supplemental opinion NRDC v. Hughes, 454 F. Supp. 48 (D.C. 1978).

[13]The draft programmatic statement for the Federal Coal Management Program was issued for review in December 1978; the final statement was filed in April 1979.

[14]Pub]ic Law 94-377, 90 Stat. 1083, Aug. 4. 1976.

[15]43 U.S.C. 1701 et seq.

[16]44 F.R. 42583, July 19, 1979.

“’'Multiple use” means the combination of resource values that consider changing needs and conditions, long-term needs for both renewable and nonrenewable resources, land productivity, environmental values, and economic return (43 U.S,C, 1702(c)). “Sustained yield"' means the achievement and maintenance of high output of public lands natural resources consistent with multiple use (43 U.S. C. 1702(h)). See also 43 U.S. C. 1701(a)(9).

[18]42 U.S.C. 7 152(b).

[19]Trust Co. v. Samedan Oil Corp., 192 F.2d 282, at 284 (10th Cir. 1975). The conditions of diligent development and continued operation are traditional in mineral leases and under common law the meaning of diligent development evolved with slightly different meanings for different minerals. Much of the common law which defined diligent development resulted from oil and gas leases in which conditions and expectations for diligent development are quite different from coal leases because the existence of commercially producible oil and gas is usually not known. The discussion of diligent development here focuses on the concept as it applies to coal leases. A recent Texas case involving private leases with an indefinite lease term held that a coal lessee has a duty to develop the leased lands within a reasonable period of time unless the lease specifically sets out the scope of the lessee's duties—such as initiation of production within a specific period of years. See Cleghorn vs. Dallas Power & Light Co., 611 S.W. 2d 893 (Tex. App. 1981) (Texas Ct. of Civ. App., Jan. 21, 1981).

[20]The Mineral Leasing Act of 1920 allowed the DOI to accept advance royalty payments in lieu of requirements for continued operation. The DOI issued coal leases permitting payment of royalties in lieu of continued operations, but until 1973 had effectively nullified the minimum royalty requirements by setting the minimum royalty equal to the annual rental (i. e., no additional payments beyond the normal rental rates were required). There are a few leases that were issued between 1973 and passage of the 1976 FCLAA that require payment of advance royalties based on a predetermined rate of production for the sixth and succeeding years of the lease (Office of Technology Assessment, Management of Fuel and Nonfuel Minerals in Federal Land: Current Status and Issues, Washington, D. C.: OTA, 1979).

[21]See 41 F.R. 21779, May 28, 1976, In considering passage of FCLAA, Congress was aware of the diligence requirements for production on existing leases within 10 years in the proposed and final regulations. Among the reasons cited for vetoing FCLAA, President Ford said that the May 1976 regulations made many of the provisions of the Bill unnecessary. See Statement of Representative Mink at 122 Cong. Rec. H8311, at H8312 (daily cd.) Aug. 4, 1976.

[22]41 F. F/, 56643, Dec. 29, 1976.

[23]Public Law 95-51, sec. 302(b), 91 Stat. 579: 42 U.S.C. 7152(b).

[24]Public Law 94-377, 90 Stat. 1083, 30 U.S.C. 201(a)(2)(A). The language in sec. 3 of FCLAA is very broad, and, given a strict interpretation, would bar the issuance of any new leases

for coal or for oil, natural gas, or other minerals under the Mineral Leasing Act to any coal lessee who continues to hold a lease for 10 or more years without producing coal in commercial quantities. The section provides that "The restriction does not apply if production on the lease has been suspended under 30 U.S.C. 207(b), as amended, because of strikes, the elements, or casualties not attributable to the lessee. "

[25]43 CFR 3400.0- 5(cc).

[26]43 CFR 3475.5(a)

[27]30 U.S.C, 207(b) and 30 U.S,C. 209.

[28]According to 30 U.S.C. 207(b), post-FCLAA lessees are subject to the conditions of diligent development and continuous operations except when operations are interrupted because of strikes, the elements, or casualties not attributable to the lessee. However, the final sentence in the subsection provides that nothing in this subsection (207(b)) shall be construed to affect the requirement in subsection (a) that leases not producing at the end of 10 years shall be terminated. This proviso has been interpreted to mean that no extensions of any kind are available for post-FCLAA lessees. However, FCLAA did not restrict the Secretary's authority in sec. 39 of the Mineral Leasing Act (30 U.S. C. 209) to suspend the operation of any lease in its entirety in the interests of conservation. The Secretary could suspend the term of a lease, and the diligence obligation, under the general authority of sec. 39. Thus, providing some delay in the running of the diligence clock for post-FCLAA lessees. (Sec. 14 of FCLAA did amend sec. 39 slightly, by limiting the Secretary's authority to waive, suspend, or reduce advance royalties paid in lieu of continued operation of a lease.) See "Discussion Paper: Existing Leases and PRLAs," in U.S. Department of the Interior, Final Environmental Statement on the Federal Coed Management Program, app. I at p. I-26, 1979.

[30]See 43 CFR 3475.4(b)(2). On Feb. 1, 1980, proposed guidelines for deciding on applications for discretionary extensions under this regulation were published for comment. 45 F.R. 7138. In January 1981 final guidelines were approved by Under Secretary Josephs of the Carter administration. As of May 1981, the Reagan administration had not yet decided whether to adopt these guidelines.

[31]43 CFR 3473.4(d).

[32]Advance royalties were required of all leases on adjustment under 1976 pre-FCLAA regulations (since rescinded). The pre-FCLAA advance royalty regulations might have had a significant effect on lease development. Had these regulations remained in force, the schedule for advance royalty payments in 1990 for 249 currently undeveloped leases with no mine plans, assuming that none of these leases were producing, could have been over $200 million. This is more than 9 times the $24.6 million paid in coal royalties in 1979. This estimate assumes that all leases would be readjusted and uses an average royalty rate of $1.25/ton (12.5 percent royalty per ton paid on an average price per ton of $ 10.00). The annual production schedule for applying advance royalties to the 249 undeveloped leases would be $165 million tons (6.6 million tons of recoverable reserves divided by 40 years resulting in annual payments of $206 million. This amount would probably have been significantly higher than the royalties paid on actual production to meet the l-percent annual production rate for continuous operations,

[33]See 43 CFR 3473.3-2(b).

[34]30 U.S.C. 188.

[35]In such proceedings, the interpretation of the law by the agency charged with enforcing it is given great weight although it is not necessarily controlling. The lessee can also raise various defenses to the action and to the application of DOI's diligence standard to his lease. Thus, even if the lessee does not meet DCI's diligence requirements. the final decision on the facts and the law will be made by the court.

[36]"We believe that the Secretary has the discretion to establish standards such as these for lease cancellation. The standard described in 3523.2-1 clarifies those conditions that would not be considered when a lessee applies for an extension to avoid lease cancellation." 41 F.R. 21780, May 28, 1976. The current regulations on cancellation of leases (43 CFR 3452.2-1(c)) list a number of adverse circumstances that will not be considered in deciding whether to cancel a lease. The circumstances listed are essentially the same as those listed in 43 CFR 3475.4(b)(l) as conditions that are not extraordinary, and hence do not qualify for extensions of diligent development deadlines. These conditions include: 1) normally forseeable business risks such as fluctuation in prices, sales, or costs, including foreseeable costs of complying with requirements for environmental protection; 2) commonly experienced delays in delivery of supplies or equipment; or 3) inability to obtain sufficient sales. The preamble to the Dec. 29, 1976 final regulations states that these provisions limit the DOI's discretion to decide against cancellation. In its discussion of the reason for setting minimum production levels for continued operation a 1 percent rather than 2½ percent annually the preamble says: "If the lessee produces less than the rate specified in the mining plan, the DOI may cancel the lease for failure to comply with the plan; however, if the lessee fails to produce 1 percent annually, the DOI's discretion to decide against cancellation would be substantially limited as set forth in 43 CFR 3523.2 -l(b)(1)(i) (remodified as 3452.2-l(c), This ability to elect whether or not to cancel a lease if annual production is between 1 percent and the higher rate specified in the mining plan provides the DOI with leverage to pressure those in arrears to increase production and to cancel leases when there is not a good faith effort to comply with the mining plan" (41 F.R. 56,646, Dec. 29, 1976).

[37]Secretarial Issue Document on Federal Coal Management Program, Department of the Interior, March 1979, issue paper No. 14. In the preamble to the May 1976 regulations, it was observed that: "It should be understood that, while the DOI has provided a definition of diligent development for the future, it reserves the right to sue for cancellation of existing leases where lessees have not made a reasonable effort heretofore to develop the coal resources, " 41 F.R. 21780, May 28, 1976.

[38]90 Stat.1086, 30 U.S.C, 202(a)(4).

[39]After an LMU has been designated under sec. 5 of FCLAA, any mine plan approved for that LMU "must require such diligent development, operation, and production so that the reserves of the entire unit will be mined within a period established by the Secretary which shall not be more than 40 years." While not requiring amendment of lease terms to incorporate the diligence requirements, these conditions on a mine plan approval could result in production exceeding requirements of the 1976 regulations for diligent development and continued operations which allow a pre-FCLAA lessee to mine his lease for 97½ years after meeting diligence,

[40]See for example, the lease form reprinted in Hearings on Federal Coal Leasing Before the Subcommittee on Mines and Mining of the House Committee on Interior and Insular Affairs. 94th Cong., 1st sess. (1975), at p. 41.

[41]A lease provision incorporating subsequent regulations makes viola lion of these regulations grounds for cancellation under sec. 31 of the Mineral Leasing Act which provides that leases may be canceled for breach of general regulations that were in effect a t the date the lease was issued. If, however, the 1976 diligence regulations are determined to be only interpretive regulations (i.e., those advising lessees and the public of the DOI's view of diligence under the act], then the limitation on regulations in effect at the date of issuance is not applicable

since the cancellation would be for violation of the act as interpreted by DOI. Departmental interpretations of matters committed to their discretion are generally followed by the courts even though alternative reasonable interpretations be made. Over time, departmental interpretations of law can become binding on DOI, See Andrus v. Shell Oil Co.,—U.S.—No. 78-1815, June 2, 1980 (Slip Opinion) p. 15.

[42] Mobil sued DOI in the District Court of Wyoming challenging the Secretary's authority to impose diligent development regulations on its Rojo Caballo lease in Campbell County, Wyo. The settlement provided that: 1) Mobil agreed to dismissal of the lawsuit with prejudice: 2) Mobil would take all steps necessary after mine plan approval so that a mine capable of producing coal in amounts to meet diligence would be in place not later than June 1, 1989: and 3) The extension is applicable to Mobil only and cannot pass with any assignment of more than 49 percent of the interest in the lease to anyone other than a Mobil affiliate. On Apr. 23, 1980, Secretary of Interior Cecil Andrus signed a letter approving Mobil's application for an extension of the diligent development deadline to June 1, 1991. The extension approval was based on information submitted by Mobil that it had contracts demonstrating that it could market the necessary 2½ percent of the LMU reserves after 1986.

[43] U.S. Department of the Interior, Secretarial Issue Document on the Federal Coal Management Program, Issue Paper No. 14, July 1979.

[44] See defendant's Brief in Support of Its Cross-Motion for Summary Judgment, Mobil Oil Corp. v. Andrus, No. C79-110B (D. Wyo. 1980).

[45] See 43 CFR 3475.5(c) and 3452.1.

[46] 30 U.S.C. 202(a),

[47] 43 CFR 3400.0-5 defines MER but does not impose specific requirements on existing leases.

[48] Proposed rules including MER requirements were published on May 19, 1980 (45 F.R. 321 15). In spring of 1981, DOI announced that substantially revised proposals for MER and diligence regulations were under consideration with publication for public comment tentatively scheduled for autumn 1981.

[49] U.S. Department of the Interior, Annual Federal Coal Management Report Fiscal Year 1980, March 1981, pp. 26-27.

[50] California Portland Cement v. Andrus. civil No. C79-0477 (D. Utah, Dec. 30, 1980); Rosebud Coal Sales v. Andrus. civil No. C-79-1608 (D. Wyo,, June 19, 1980).

[51] See preamble to final rulemaking on the Federal Coal Management Program, 44 F.R. 42601, July 19, 1979, and 43 CFR 3451.1(d), 1980. The effect of this presumptive waiver of readjustment on the applicability of regulations issued after the prior lease date and of FCLAA provisions to the lease is not specified. However, since DOI has previously maintained that readjustment is not necessary to make general regulations applicable to the lease, DOI probably would argue that waiver would have little effect because the regulations were applicable on promulgation not readjustment.

[52] See "Discussion Pa per," Existing Leases and PRLAs, supra. note 28. p. 1-26.

[53] 43 CFR 3452,1-1.

[54] 90 Stat. 1083, 30 U.S.C. 201(a).

[55] See 43 CFR 3475. (b)(2).

[56] 43 CFR 3435.

[57] The exchanges proposed under special legislation include: over 800 million tons in Federal leases along Interstate 90 in northeast Wyoming: over 300 million tons of PRLA reserves in southwestern Utah; and up to 60 million tons on leases in the Bisti area of New Mexico. Additionally. as much as 400 million tons of reserves in the Lake DeSmet lease blocks might qualify for exchange under SMCRA and over 130 million tons of Federal bypass lease reserves could be involved in the Northern Cheyenne lease cancellations.

[58] Public Law 95-554, 92 Stat. 2269, Oct. 30, 1978, House Rep. 95-469. See also, Cong. Rec. H11391, Oct. 3, 1978 (daily cd.). Among other things, the amendments clarified that coal removed during construction of a right-of-way did not have to be leased competitively and provided that higher minimum royalty rates did not apply to modified leases until expiration of their current terms.

[59] Bureau of Land Management, Lake *DeSmet* Exchange Study, Wyoming State Office, Johnson County, Wyo., July 1979. Texaco is the major holder of private land and mineral rights and only holder of Federal leases in the Lake DeSmet area. The acquired lands would have been used for recreation purposes. Even though the exchange was not approved, Texaco feels that reserves on several Federal leases in the block may qualify for exchange under sec. 510(b)(5) of SMCRA (letter from R.T. Carter, Vice President, Coal and Energy Resources Department, Texaco. to OTA, dated Dec. 19, 1980).

[60] Energy Daily, June 17, 1981, p. 3. The rejection followed negative recommendations by the U.S.G.S. economic evaluation unit on the value of the PRLAs because the PRLAs are located far from existing coal transportation networks. (Personal communication to OTA, U.S.G.S. Conservation Division, Denver, Colo., Dec. 15, 1980.) GAO also circulated a draft report on the exchange questioning the validity of the PRLAs because the applicant did not have an approved prospecting permit when exploratory drilling was conducted on two PRLAs: and the lack of data on the coal reserves required for making the "equal value determination": and expressing concern over the competitive effect of giving Utah Power & Light highly desirable coal lands in central Utah. Letter of Apr. 2, 1981 from J. Dexter Peach. Director, Energy and Minerals Division. GAO, to James G. Watt, Secretary of the Interior. The Utah Power & Light exchange is discussed in the final environmental statement on the Uinta-Southwestern Utah Lease Sale, Bureau of Land Management. 1981.

[61] Several of the Wyoming leases under consideration for exchange were reviewed by the OTA Wyoming task force and are discussed in ch. 6 of this report. The Interstate Highway exchange proposal includes parts of the existing Wyodak Mine and two lease blocks with favorable production prospects by 1986 (Kerr McGee's East Gillette Federal and Carter's South Rawhide Mines). Two other leases—Armstrong and Gulf (No. 3) were given unfavorable development prospects. The final lease, Belco, has uncertain development prospects-contingent on in situ gasification—with unfavorable production prospects in 1986 and 1991. Gulf Oil Co. has requested that the Gulf (No. 3) lease be exchanged for a corridor of unleased Federal coal that splits its Wildcat lease in Campbell County.

[62] 94 Stat. 2269, Oct. 19, 1980).

[63] See Senate Report 96-800. accompanying S. 1455 (June 19, 1980).

[64] 94 Stat. 1701, Senate Report 96-883.

[65] See statement of Senator Melcher, 126 Cong. Rec. S. 11142 (daily cd.), Aug. 18, 1980. According to information obtained at the OTA Wyoming task force, up to 1 billion tons of coal is covered by these leases and permits. Peabody Coal Co., holder of the seven leases and three permits, is seeking rights to 130 million tons of Federal bypass coal in return for cancellation of its tribal lease claims.

[66] 30 U.S.C. 1260(b)(5).

[67] Regulations providing for alluvial valley floor exchanges were challenged as part of litigation involving the surface mining act regulations. The AVF exchange regulations were remanded to DOI to include provisions implementing the mandatory exchange program for non-Federal lands. See con-

ference report on H.R. 2, House Report 95-493, July 12, 1977, pp. 104-105:

The Senate amendment also provided authority for the Secretary of Interior to lease Federal coal deposits as an exchange relinquishment of a Federal coal lease for coal affected by this alluvial valley floor constraint. Such an "exchange" would be limited to those operators who had made a "substantial legal and financial" commitment to mine such coal prior to Jan. 1, 1977. Similar exchange authority under sec. 206 of the Federal Land Policy and Management Act of 1976 was granted the Secretary with respect to "fee" coal owned in alluvial valley floors. Both of these authorities were discretionary on the part of the Secretary.

The conferees also stipulated that the Secretary develop and carry out a coal exchange program for fee coal located in alluvial valley floors under the provisions of sec. 206 of the Federal Land Policy and Management Act of 1976.

The language added by the conferees to the "Wallop Amendment" of the Senate version is designed to make it clear that the Secretary should actively implement the coal exchange program. This program would apply to all those private coal deposits, regardless of any previous financial or legal commitments, which the Secretary determines cannot be mined because of the provisions of sec. 510(b)(5). The program would not apply to privately owned coal which might have been mined in the same operation but which can still be mined.

*43 U.S.C. 1716, Regulations implementing sec. 206 have been promulgated but are under review by the Reagan administration.

'[9]Exchanges of checkerboarded lands covering critical winter range for big game species in the Atlantic Rim area near Rawlins, Wyo. have been suggested. See also, R. C. Anderson and A. Silverstein, Management *of* Federal *Coal* Properties in Areas *of* Fragmented Resource Ownership (Washington, D. C.: Environmental Law Institute, 1980) for discussion of exchanges for unitization of coal reserves.

[70]See Management *of Fuel* and *Nonfuel* Minerals in Federal Land, Office of Technology Assessment, April 1979, ch. 3, for discussion of various provisions for obtaining development rights for other leasable and hardrock minerals.

[71]See ch. 3 of this report.

[72]90 Stat. 1085. There were about 192 prospecting permits pending on passage of FCLAA and 28 prospecting permits. The number of PRLAs has dropped as some applications were rejected and now fluctuates between 171 and 178 depending on the results of various appeals of rejected applications. All prospecting permits have since expired. As of March 1981 the number of PRLAs had dropped to 171 as a result of: 1) addition of two new applications because of litigation challenging the DOI's denial of extensions of prospecting permits for which no applications had been filed at the time the 1976 FCLAA was enacted; and 2) the withdrawal of seven applications.

[73]The Summary Paper on Management of Preference Right Lease Applications (Office of Coal Leasing Planning and Coordination, *Secretarial Issue* Paper: Formulation *of* Proposal *for Coal* Programmatic *Environmental* Impact Statement (Washington, D. C.: U.S. Department of the Interior, June 23, 1978, Tab I) estimated maximum potential production from pending PRLAs to range from 186 million tons/year (if legal, probable and possible planning and environmental restrictions are applied) to 248 million tons (no restrictions applied). This was based on 40-year mine life on estimated recoverable reserves of 9.9 billion tons. The estimated reserves under PRLAs have been subsequently reduced to 5,7 billion tons (due primarily to elimination of an estimated 3.6 billion tons of subbituminous underground reserves in the Wyoming Powder River basin). If the lower reserve figures are substituted for those in the Secretarial issue paper, the range of potential production drops to between 108 million and 144 million tons, OTA's analysis of PRLAs in Wyoming indicates that approximately 40 million tons of potential production capacity in this revised number have unfavorable development prospects (see ch. 6 and OTA's Wyoming task force report). When OTA's estimates of potential production capacity of PRLAs in Wyoming with favorable or uncertain development prospects (20.5 million tons/year) are substituted for the revised numbers for Wyoming in the Secretarial issue paper, the range of total production potential becomes 69,5 million to 102.5 million tons/year. OTA's analysis of production potential of PRLAs in the 1990's is based on the following modifications of DOI's production estimates: Colorado, 9 million to 17 million tons; Montana, zero to 7.7 million tons; New Mexico, 7,5 million to 9.5 million tons; Oklahoma, zero to 0.4 million tons; Utah, zero to 6.5 million tons; Wyoming, 20 million tons. OTA's adjusted annual production totals yield a range of 35 million to 60 million tons including about 10 million tons of production capacity associated with existing leases and reflected elsewhere in this report as Federal mine production. Total new annual production potential of PRLAs would thus be between 25 million and 50 million tons. Some PRLA reserves in eastern Colorado and Wyoming were found to have some potential for use as a feedstock in synthetic fuels processes, but substantial production from these PRLAs is likely only if there is greatly expanded demand for such coal in the 1990's.

[74]Initial production from most PRLAs can be expected in 1988-94 assuming that it takes about 6 years for mine development from the date of lease issuance. Several groups of PRLAs will be issued during 1981 to 1982 under an accelerated processing schedule: these PRLAs include four in Colorado and the Arch Mineral PRLAs in New Mexico.

[75]105 of 172 applications submitted to BLM did not contain information proving that commercial quantities had been discovered, but rather stated that the requisite data had been provided to the U.S. Geological Survey, Seventy-five PRLAs were filed without the required qualifications statement describing the applicant, and 70 PRLAs were filed without precise descriptions of the acreage covered by the application. In addition, 25 PRLAs did not file initial showings in a timely manner required under the 1976 regulations (Coal task force No. 124, An Evaluation *of* Coed Preference *Right* Lease Applications, Washington, D. C., U.S. Department of the Interior, April 1978). In most instances, the regulations or DOI practices allow the applicant to correct the application by supplying the required information, If the applicant does not respond with the requested information then the application can be rejected. See, for example, 43 CFR 3430.2-2, 1980.

[76]Coal task force paper No. 124 identified six PRLAs that did not properly indicate the existence of recoverable reserves and four PRLAs that were not filed before the expiration date of the prospecting permit. Several of these PRLAs have subsequently been rejected.

"Preference right leases were issued in 1974, 1975, 1976, and 1977 in accordance with short-term leasing criteria in effect at that time. The four leases (one issued in each of those years) range in size from 175 to 14,902 acres.

[78]See 41 F.R. 18845, May 7, 1976 (final rules); see also proposed rules published at 41 F.R. 2648, Jan. 19, 1976.

"According to the Preamble to the Proposed Rules, use of the workability standard for classification resulted in a determination of commercial quantities "based solely on the physcial characteristics of the mineral without regard to costs such as transportation and reclamation, " The use of this standard was rejected. 41 F.R. 2648.

'43 CFR 3430.1-2.

[81]43 CFR 3430.5.

[82]*NRDC* v. *Berklund*, 458 F. Supp. 925 (D.D.C. 1978).

'[3]458 F. Supp. 937.

[84]458 F. Supp. 937.

[85]The ability of DOI to exchange leases or PRLAs for unleased Federal coal without specific congressional approval is relatively limited, but 43 CFR 3435.1 allows PRLAs to be relinquished in exchange for other rights, including: 1) the issuance of coal lease bidding rights of equal value; 2) a mineral lease other than coal by mutual agreement by the applicant and DOI; and 3) modification of other coal leases held by the applicant.

[86]458 F. Supp. 938. The decision notes that it left open the question of whether such withdrawal would constitute a taking since, under 43 U.S.C. 1701, withdrawals are subject to valid existing rights.

[87]*NRDC* v. *Berklund*, 609 F. 2d 553 (D.C. Cir. 1979).

[88]448 F. Supp. 962 (D. Ut. 1979)

[89]448 F. Supp. 988 (D. Colo. 1979).

[90]A total of 118 certified abstracts were received by DOI, as well as 21 certificates and 9 letters. Nineteen applicants did not respond and five PRLA holders were not contacted because of pending litigation.

[91]Bureau of Land Management Instruction Memorandum No. 76-646, change 2, Dec. 19, 1979.

[92]See 30 U.S.C. 521-523, especially 30 U.S.C. 524, 525, 526 and 527.

[93]43 U.S.C. 1744.

[94]43 CFR 3430.1-2

[95]*Samuel Pulford*, 45 L.D. 484, 1916.

[96]*NRDC* v. *Berklund*, 458 F. Supp. 925 (D. D.C. 1978).

[97]The legal basis for this argument is set forth in a letter from Terence Thatcher, counsel for the National Wildlife Federation to Frank Gregg, Director, Bureau of Land Management (re: comments on Bureau of Land Management Proposed Coal Leasing Management Regulations: PRLAs, May 18, 1979). In 1975, the Environmental Defense Fund and Natural Resources Defense Council concluded that a number of PRLAs in the Powder River basin, Wyoming could be challenged on this basis, but decided that litigation challenging such PRLAs would need to be done on a case-by-case basis when (or if) the leases were actually granted.

[98]44 F.R. 42599, July 19, 1979.

[99]See 30 U.S.C. 1260(b) abd 30 U.S.C. 1272(a).

[100]30 U.S.C. 1272(a)(3).

[101]See 16 U.S.C. 1.

[102]Some PRLAs in the San Juan Basin of New Mexico are located within a few miles of Chaco Canyon National Monument and its "outliers". Chaco Canyon was established primarily to preserve the Indian archeological sites there: it is likely that any protective stipulations on mining in the area would be directed at minimizing any harmful effects of mining on the archeological sites and not at preserving scenic vistas.

[103]See notice at 46 F.R. 30202, June 5, 1981.

CHAPTER 10

Implications-of Environmental and Reclamation Issues for the Development of Federal Coal

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CHAPTER 10

Implications of Environmental and Reclamation Issues for the Development of Federal Coal

This chapter considers the extent to which environmental and reclamation concerns may affect the production of Federal coal. Primary emphasis is placed on documentation of those cases where mining of recoverable coal reserves has been delayed or prevented. A brief discussion is also included on the effect that environmental and reclamation concerns have on the cost of mining Federal coal. The chapter is not an analysis of the effects of coal mining on the environment, although those issues are briefly discussed in order to provide a context for the chapter. Background information is also provided on the environmental characteristics of Western coal regions and the existing framework for coal mine regulation.

Environmental Overview of Coal= Producing Regions

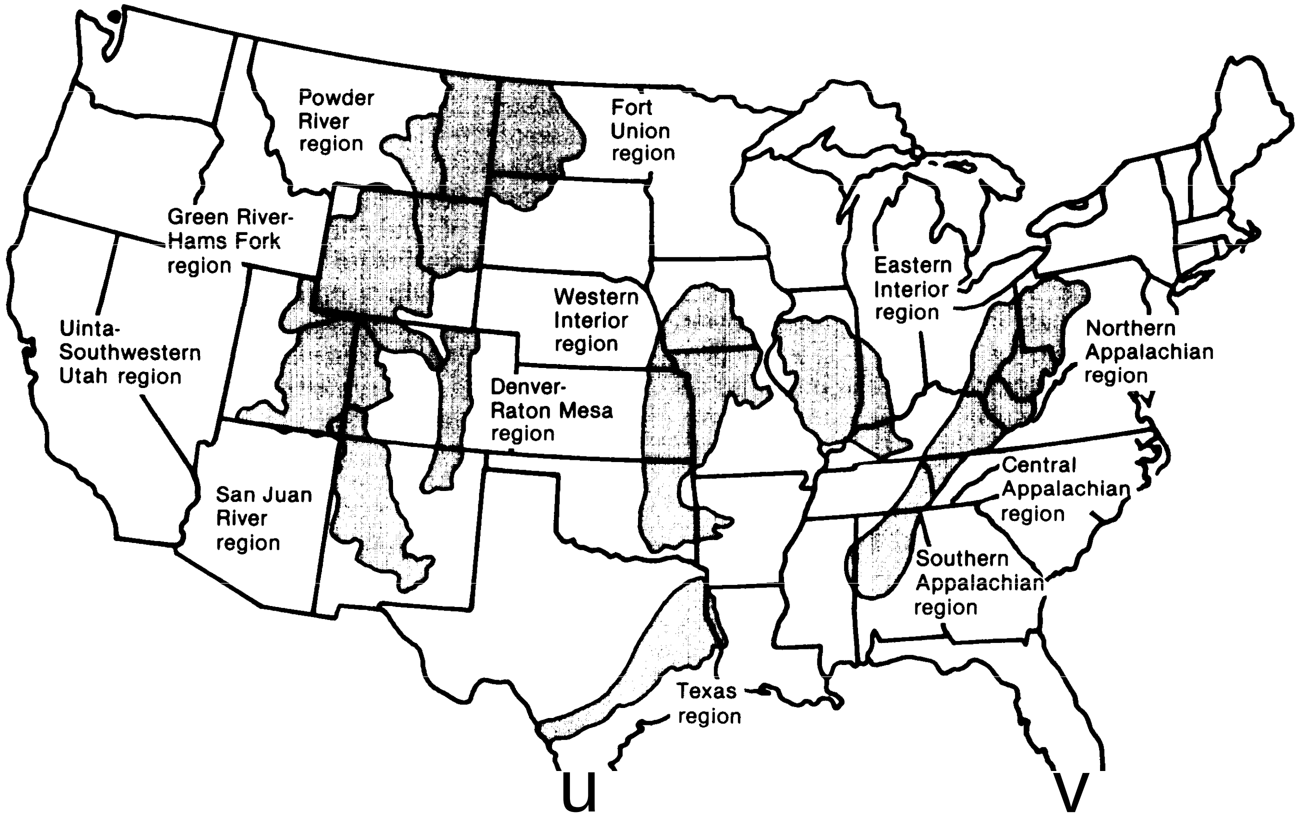
The United States can be divided into 12 major coal-producing regions (fig. 43). Federal coal accounts for a large portion of the coal reserves of the six westernmost regions. In addition, Federal coal reserves are significant in the extreme southern portion of the Western Interior region in Oklahoma. * This section reviews the important environmental characteristics of these seven coal regions, pointing out regional similarities as well as noting differences. Emphasis is placed on discussion of those characteristics that are of most importance to the mining of Federal coal reserves, and on the potential for success in reclaiming mined lands. This section serves as background to the discussion of reclamation and environmental issues later in this chapter.

Because Federal coal reserves are concentrated in the Western United States, the environmental characteristics of mining and reclamation of Federal coal differ from the mining of the other coal reserves of the Nation. Only the Federal coal reserves of Oklahoma in the Western Interior region have environmental characteristics similar to the characteristics of the privately held reserves of the Midwest and Eastern United States.

The Western United States is notably distinct from the rest of the country in its overall lack of available water, its shallow soils, and its high erosion rates. These factors combine to make reclamation more difficult than in other parts of the country. Annual mean precipitation in the West is low, ranging from 4 inches or less per year in some of the hot deserts to over 20 inches in the higher mountains. Droughts are common in the West, and precipitation is more commonly below average than above. Particularly during periods of drought, precipitation may occur in short, intense storms that have the potential to cause severe erosion. Temperatures in the West fluctuate widely, and high summer daytime temperatures can quickly dry out soil and seeds.

*Alaska has substantial coal resources on Federal lands, and there are also scattered areas of federally owned coal reserves in the eastern regions and in Texas. These coal regions are not considered in this report because of the relatively minor amounts of Federal coal there currently under lease compared to leased reserves in the seven States of Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming.

Figure 43.—Tweive Coai Suppiy Regions of the United States



SOURCE: U.S. Department of the Interior, Final Environmental Statement, Federal Coal Management Program (Washington, D. C.: U.S. Government Printing Office. 1979), p. 1-4.

Soil is poorly developed in the semiarid and arid West. Rocks weather slowly, and organic matter accumulates slowly. The resulting soil profile is loose and undifferentiated and has little capacity for holding moisture. In much of the West, rates of erosion are among the highest in the country, and soil can be lost because of flash flooding and hillslope erosion.

Vegetative succession is a slow process in the West because of climatic severity. A disturbed site in the Eastern United States may revegetate itself in 5 to 10 years, but decades or centuries maybe needed for natural revegetation in the West. Thus, natural revegetation cannot be relied on to rehabilitate disturbed sites, and careful planning is needed.’

Tables 80, 81, and 82 summarize the environmental characteristics of the seven coal-producing regions with major reserves of Federal coal. The information is separated into three categories: physical characteristics (table 80), environmental resources (table 81), and social characteristics (table 82).

‘Previous three paragraphs adapted from National Academy of Sciences, Rehabilitation Potential of Western Coal Lands (Cambrdige, Mass.: Ballinger Publishing Co., 1974),

Table 80.—Physical Characteristics

Region: State(s)	Physical division and subdivision	Topography	Soil orders[b]	Climate[c]
Western Interior: Oklahoma	Central Lowlands Division Upper Missouri Basin Subdivision	Gently sloping hills	Mollisols Inceptisols	Evaporation: 64-80"/lyr. Mild temperatures: 400 winter >800 summer Precipitation: 32-48''/yr. Winds: 11-14 mph Dust storms and tornadoes common
Fort Union: Montana North Dakota	Great Plains Division Upper Missouri Basin Subdivision	Gently undulating land surfaces; relief less than 20 ft. in glaciated areas. Gently sloping, roiling prairie, with isolated buttes, mesas and badlands in unglaciated areas.	Mollisols Entisols	Evaporation: 46-64''/yr. Semiarid continental Long cold winters, short warm summers. Mean annual temperature: 38-45 "F Precipitation: 12-16''/yr. thunderstorms frequent Winds: 10 mph
Powder River: Montana Wyoming	Great Plains Division Upper Missouri Basin Subdivision	Undulating land, Surface highly dissected in some areas.	Aridisols Mollisols Entisols	Evaporation: 48-64''/yr. Semiarid continental Mean annual temperature: 45"F Precipitation: 14''/yr. (75% of ppt. occurs from Apr. -Sept.) Chinook winds: warm, dry, 25-50 mph, Aug. windy-12 mph.
Green River-Hams Fork: Colorado Wyoming	Middle Rocky Mountain Division (Wyoming - Big Horn Basin Subdivision)	Complex mountains and basins, generally a series of parallel ranges. Local relief up 2,000 ft, but generally less than 1,000 ft.	Aridisols Mollisols	Evaporation: 48''/yr. Semiarid continental Mean annual temperature: 37-46 "F Precipitation in NW: 16-32''/yr. in rest of area: 8-16"/yr.
Uinta-Southwestern Utah: Colorado Utah	Colorado Plateau Division and Subdivision	Varied: peaks and plateaus rising from lowlands. Extremely steep slopes and narrow, vertically walled canyons. High plateaus of stratified rock cut by deep canyons in southwestern Utah.	Aridisols Mollisols Entisols Alfisols	Evaporation: North 48-64''/y.; South 64-80"/yr. Arid for most of the regions with varied weather patterns in the mountains (some of which maintain year round snow cover) Precipitation: 30% of area receives 0-8"/yr., rest of area (except mountains): 8-16''/yr. mountains: > 20"/yr.
San Juan River: Colorado New Mexico Utah	Colorado Plateau Division and Subdivision	Basins with mesas, rolling plains, and badlands	Entisols Aridisols	Semiarid Mean annual temperatures: 48-52 'F Mean annual precipitation: less than 10" to 20" Summer thunderstorms. Evapotranspiration exceeds precipitation by a factor of 6:1
Denver-Raton Mesa: Colorado New Mexico	Southern Rocky Mountain Division Rocky Mountain, Piedmont and Southern Rocky Mountains Subdivision	Eastern portion: gentle plains Western portion: Steep slopes and foothills	Alfisols	Evaporation: 64-80''/yr. Semiarid continental Mean annual temp.: 48-520 F Precipitation: 13-18''/yr., low humidity, light rainfall, periodic droughts Winds: 10 mph

[a]Physical division based on classes defined by Nevin Fennemen (National Atlas). Physical subdivisions based on classes defined by Edwin H. Hammond.
[b]Soil types listed in chart in order of dominance, Definitions of soil orders follows:

Arid ISOIS: These soils are found in arid regions. They have both a low moisture content and absorb precipitation slowly, thus most precipitation runs off. There is a period of about 3 months during the year when the soil is both warm and moist enough for plant growth. The vegetation which these soils can support without irrigation is limited to ephemeral grasses and cacti.

Entisols: These soils are in early stages of development, and thus lack defined layers down to a depth of 50 cm. They exhibit a wide range of moisture content and temperature. These soils characteristically develop on steep, actively eroding slopes, and on flood and glacial outwash plains.

Mollisols: These soils are found throughout the subhumid to semiarid plains of North America. Mollisols retain enough moisture to support perennial grasses and many have been forested or have had grass vegetation. In areas of suitable c1 imatic conditions, they are used to produce grains, sorghum, corn, and soybeans

Alfisols: These soils are characterized by a clay horizon which is capable of holding moderate amounts of water. Their moisture retention is sufficient to sustain plant growth for at least 3 months of the year, provided the soil is warm enough

Inceptisols: These soils have weakly differentiated horizons Materials in the soil may have been altered or removed, but have not accumulated. Although generally moist, these soils tend to dry out in the warm seasons

[c]Evaporation figures are for mean annual evaporation.

SOURCE: Class A pan-National Atlas.

Table 81.—Environmental Resources of Coal-Producing Regions

	Air quality	Water quantity and quality	Vegetation	Wildlife	Agriculture and land use[a]	Carrying capacity livestock[b]
Western Interior	Overall quality: good. Urban areas: moderate NO_2 levels around Tulsa, Okla.	Surface water runoff 7". Surface water quality good.	Transitional areas: eastern forests to prairie grasses.	Species typical of forest and prairies: deer, fox, coyote, whitetail deer, small woodland mammals. Federally protected species: 6 birds, 3 mammals.	supports crops and timber harvesting. Cropland: 52% Pasture: 11% Range: 15% Forest: 10%	2.6 acres/ A.U.M.
Fort Union	Uniformly very good	Annual runoff: 1"/yr. Surface water availability limited except in major streams. Groundwater available in small quantities except in alluvial valleys where more abundant. Major streams: Missouri, Yellowstone, Knife.	Eastern: Wheatgrass, needlegrass. Western: Gramma, needlegrass, wheatgrass.	Varied wildlife: 87 species birds, 70 species reamreals, 200 species fish, 20 species reptiles and amphibians. Federally protected species: 4 birds, 3 mamreals.	Cropland constitutes 75% of N. E., 5% southern area. Elsewhere, Cropland: 37% Range: 54% Principal crops: wheat and grain.	8.2 acres/ A.U.M.
Powder River	Overall quality: generally good. Variations around populated areas, i.e,, Colstrip, Mont. is a nonattainment area for TSP.	Annual surface water run-off: less than 0.5". Surface water limited except along major streams. Quality: variable. Groundwater availability and quality: variable. Major streams: Yellowstone, Big Horn, Powder, Tongue, Belle Fourche, and Musselshell.	Wyoming: Prairie shortgrass, grassland sagebrush. Montana: grassland sagebrush, and ponderosa pine.	Similar to Fort Union. Federally protected species: 3 birds, 1 mammal.	Grazing and ranching. Cropland: 5% Range: 88%	15.5 acres/ A.U.M.
Green River-Ham's Fork	Overall quality very good, however, Craig, Colo. and parts of Sweetwater, Colo., and Wyoming are nonattainment for TSP.	Annual runoff: Western half: 10-30" Eastern half: .1-2" Quality good in mountains and poor in basins. Major streams: Green, Yampa, Sweetwaters, Shoshone, Greybull.	Cold desert biome: sagebrush. Salt brush biome: greasewood, mountain shrub, evergreen forests, broadleaf forests.	53 mammal species. Large numbers of big game animals. Varied game and non-game fish species. Wild horse herds. Federally protected species: 1 fish, 3 birds, 2 mammals.	Cattle and sheep ranching, limited farming. Cropland: 4°/0 Range: 70°/0 Forests: 270/o	9.3 acres/ A.U.M.
Uinta-Southwestern Utah	Rural air quality: very good. Urban areas: occasional problems during temperature inversions.	Annual runoff: 0.1-.5"/yr. Good water quality. Region contains numerous tributaries to the Colorado River: Green, White, Duchesne, Price, Dirty Devil, Paria, Escalante, & Virgin Rivers.	Vegetation varies with climate. Cold desert biome: salt brush and greasewood. Mountain Forest biome: pine, fir, spruce, and sagebrush.	Varied habitat supports many diverse species: 90 species reamreals, 270 species birds, 26 species reptiles, 9 species amphibians Federally protected species: 3 fish, 3 birds, 2 mammals.	Desert shrubland and open woodland grazing. Crops: 3°/0 Range: 62% Forests: 33°/0	8.3 acres/ A.U.M.
San Juan River	Overall quality generally good except around industrial areas. High SO_2 levels near powerplants.	Annual runoff: 0.1-O.5''/yr. Major streams: San Juan, Colorado, and Little Colorado. San Juan River is the only perennial stream in Federal lease block area. Ground waters are generally good, but levels are dropping.	Generally sparse vegetation. Lower elevations: grassland shrub and grasslands. Upper elevations: Pinyon, juniper and coniferous forests.	Habitat supports: 100 species mammals, 116 species birds, 28 species amphibians. Several are unique to region. Federally protected species: 1 fish, 4 birds, 1 mammal.	Cattle and sheep ranching. Range: 50% Forests: 45% Limited crops: corn, hay, wheat, cotton, and sugarbeets.	22 acres/ A.U.M.

Table 81. —Environmental Resources of Coal-Producing Regions—Continued

	Air quality	Water quantity and quality	Vegetation	Wildlife	Agriculture and land use[a]	Carrying capacity livestock[b]
Denver-Raton Mesa	Overall: very good. Urban areas often fail to meet national standards due to inversions and automobile induced pollution.	Annual runoff: 0.5 inches/yr. Surface water: Quantity: 5.4 million acre ft/yr. Quality: good. Major streams: South Platte, Arkansas.	Prairie biome: Buffalo grass and blue gramma. Coniferous forest in S.W.	Typical species: marmot, ground squirrel, wildcat, vole, bobcat, mule deer, elk, porcupine. Federally protected species: 1 fish, 3 birds, 1 mammal.	Agriculture supports sugarbeets and grain. Cropland: 21% Range: 56% Forests: 21 %	16 acres/ A.U.M.

a percentages are of total land area. Only major land uses are listed.
b Refers to the ability of the land to support livestock, A.U.M. stands for animal unit month, which refers to the grazing requirements of an "averaged" livestock animal for 1 month.

SOURCE: U.S. Bureau of Land Management, *Final Environmental Statement, Federal Coal Management Program, 1979.*

Table 82.—Archeological and Cultural Resources of the Western Coal Regions

Region	Archeological resources	Major Federal parklands and forests resources	1975 population	1975 Pop. per sq. mile
Fort Union	Much of the region has some identified archeological value. A few areas have large sites and/or high site density. There is a high probability of disturbance to sites in Custer Co., Mont., and in Mercer, Williams, and Oliver Co's., N. Dak.	• Little Missouri National Grassland • Theodore Roosevelt National Memorial Park • Custer National Forest	324,399	5.4
Powder River	There is a high probability of disturbance to sites in Rosebud, Bighorn and Powder River Co's., Mont, and in Johnson and Campbel Co's., Wyo. Remainder of region considered to have some archeological value.	• Devils Tower National Monument • 65 Sites eligible for, or currently enrolled on the National Register of Historic sites. • Thunder Basin National Grassland • Custer National Forest	228,418	4.6
Green River-Hams Fork	The region has some identified archeological value. Many areas have not been surveyed.	• Flaming Gorge National Recreation Area • Dinosaur National Monument	126,938	2.6
Uinta-Southwestern Utah	There is a high probability of disturbance to Fremont and Anasazi sites in Emery, Kane and Garfield Co's., in Utah. Remainder of region considered to have some archeological value.	• Capital Reef, Arches, Canyonlands, Zion, and Bryce Canyon National Parks • Cedar Breaks National Monument • Black Canyon of the Gunnison, and Colorado National Monuments	406,626	7.2
San Juan River	This region has been identified as having both great archeological and historical value. There is a high probability of disturbance to sites in the Chaco Canyon National Monument area.	• Mesa Verde National Park • 6 National Monuments	351,143	7.2
Denver-Raton Mesa	This region has some identified archeological value.	• Comanche National Grasslands	1,854,205	77.5

a Based on a survey Performed b, the National Academy of Sciences of 69 strippable coal areas in the West. Tables A.1, A.3, Rehabilitation potential of Western Coal *Lands, NAS, 1974.*

SOURCE: Office of Technology Assessment.

Physical Characteristics. Table 80 contains information on physiographic subdivisions, topography, soil orders, and climate. The topography of the Federal lease areas is varied. The Western Interior region is typified by a gently undulating prairie landscape. The northern regions (Fort Union and Powder River) are also generally characterized by low overall relief and an undulating grassland, but selected areas include badlands, ponderosa pine forests, and rocky cliffs and outcrops. The central western regions (Green River-Hams Fork and Uinta-Southwestern Utah) are located in mountainous terrain. The San Juan River region is characterized by mesas and badlands. Topography in the Denver-Raton Mesa region varies from gentle plains to rugged slopes and foothills. As noted earlier, the Western areas tend to be either semiarid or arid in climate. There are some exceptions in the mountainous areas, which tend to create localized weather patterns of higher precipitation. In all the Western regions, evaporation exceeds precipitation. The ratio of evapotranspiration* to precipitation ranges from 2 to 1 in the Fort Union region to 6 to 1 in the San Juan River region. The evaporation rates in the region range from 48 to 64 inches in a year in the northern coal regions and generally increase to a high of 80 to 96 inches a year in the southern San Juan River region, Low rainfall and high evaporation creates moisture stress throughout the coal lease areas. The moisture stress generally increases from north to south for similar elevations. Soil types reflect the topography, geology, and climate of the regions. Most of the soils have a low moisture content, but usually hold enough water to sustain plant growth for 3 months of the year.

Environmental Resources. Table 81 summarizes air quality, water resources, vegetation, wildlife, agriculture and land use, and livestock carrying capacity of the coal lease regions. Overall, the air quality of all the regions is good to very good, although atmospheric inversions are common in all the areas for parts of the day in both summer and winter. The exceptions to good air quality are in areas with extensive urban or industrial development. Areas with air quality problems include Billings and Colstrip, Mont.; portions of Sweetwater County, Wyo.; Craig, Colo.; areas around powerplant generating stations in the San Juan River region; and in the urban Colorado Front Range corridor.

Annual surface water runoff ranges from 0.5 to 2 inches for most of the coal lease regions, with most areas falling within the lower part of the range. The major exception is in the mountainous areas of the Green River-Hams Fork and Uinta-Southwestern Utah regions. Water availability in all regions is greatest in the major river valleys. The water quality of the regions' streams is difficult to generalize and ranges from variable to good. High sediment loads are common.

The coal regions are characterized by sparse growth in the lower elevations. Prairie grasses and sagebrush are the predominant species. The mountainous forests are generally characterized by coniferous tree species. Large mammals—antelope and mule deer—range throughout the regions, with the Green River-Hams Fork and Uinta-Southwestern Utah regions containing the largest number of big game animals. The San Juan River area contains a number of animal species that are unique to only that region. The number of federally protected fish, bird, and mammal species varies from four to nine in each region.

Except for the fertile Western Interior region, the predominant land use is grazing. The semiarid conditions of the West limit croplands to areas with above-average rainfall or to irrigated or subirrigated areas generally found in stream valleys. Table 81 indicates the percent of land devoted to both farming and grazing use. In addition, table 81 summarizes the average regional carrying capacities for livestock, which range from 2.6 acres per animal unit month in Oklahoma, to 22 acres per animal unit month in the San Juan River region.

*Evapotranspiration means loss of water from the soil both by evaporation and by transpiration from the plants growing in the soil.

Social Characteristics. Table 82 contains information on population, population density, and features of archeological significance in the coal lease areas. In general, the population density of the Western regions is low, except in the Denver-Raton Mesa region which reflects the significant growth that has occurred in the Denver region.

The archeological history of most of the Western region dates back to the Paleo-Indian big game hunting tradition of the pre-8000 B.C. period, and to the Desert Culture of the period from 9000-4000 B.C. The regions also contain remains of early Indian cultures, the most significant of which is the Anasazi people and the remains of their multistoried pueblos in the Southwest that date back to 1000 A.D. Although all of the regions are considered to have some archeological significance, the San Juan River region has the greatest archeological value.

Regulatory Framework

Federal regulation of the environmental effects of surface coal mining operations, including the surface effects of underground mining, was initiated on August 3, 1977 when President Carter signed into law the Surface Mining Control and Reclamation Act (SMCRA) (Public Law 95-87).[2]

In brief, the Surface Mining Act establishes a detailed national program for addressing environmental effects of coal mining. Of particular importance is the act's establishment of environmental protection performance standards (sec. 515) and provisions for designation of lands as unsuitable for coal mining (sec. ***522).*** The performance standards of section 515 are minimum standards applicable to various aspects of the mining and reclamation process. Under SMCRA, the States may, if they choose, impose standards that are more stringent. Among other things, the standards require:

- maximum utilization and conservation of the coal being recovered;
- restoration of disturbed land to original or better conditions;
- restoration of the approximate original contour of the land surface;
- stabilization and protection of all surface areas;
- protection of prime farmlands through specific reclamation techniques;
- minimization of disturbances to the existing hydrologic balance; and
- limitation of mining on steep slopes.

Section 522 of the act establishes a procedure to designate lands as unsuitable for all or certain types of coal mining operations. The Secretary of the Interior determines unsuitability for Federal lands, while States have authority over non-Federal lands. Areas may be designated unsuitable if, upon petition, it is determined that reclamation of disturbed lands is not economically or technologically feasible. Areas may also be designated unsuitable if mining operations will:

- be incompatible with existing land use plans;
- significantly affect important fragile or historic lands;
- result in substantial loss or reduction in the productivity of renewable resource lands which produce food or fiber; or
- substantially endanger life and property in natural hazard lands.

The act requires that the Department of the Interior (DOI) obtain the consent of certain private surface owners before Federal coal underlying their lands can be leased. The act restricts mining activities affecting alluvial valley floors. Section 510(b)(5) of the act allows the Secretary of the Interior to trade unleased Federal coal reserves for existing leases or non-Federal lands that cannot be mined because of alluvial valley floor des-

[2]91 Stat. 445, 30 U.S,C. 1201 et. seq.

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ignations provided that coal is not yet being produced from the mine and the operator had made a substantial legal or financial commitment to develop a mine before January 1, 1977. The act also requires the Secretary to exchange non-Federal coal lands in alluvial valley floors that cannot be mined for available Federal coal lands of comparable value; these exchanges are not subject to the requirement of substantial legal and financial investments.

The act also created the Office of Surface Mining Reclamation and Control (OSM) within DOI to implement the statute's various programs. The act mandates compliance with detailed technical performance standards by operators on private as well as on Federal and State lands. The act originally provided for slightly less than 3 years of Federal enforcement of State-issued operating permits implementing the most stringent of the act's performance standards (known as the "interim regulatory program") followed by implementation of the remaining standards (known as the "permanant regulatory program"). At the end of 3 years (June 3, 1980), primary regulatory responsibility for the program was to have shifted to those States who had their proposed program for assuming regulatory primacy approved by DOI. In those States in which primacy was not achieved, a Federal program was to have been implemented and administered by OSM. Three and one-half years after enactment of the statute, all mining operations were to have been in compliance with permits issued in accordance with the full range of regulatory requirements, as administered by either the States or OSM.

Litigation brought in the District Court for the District of Columbia by several of the major coal companies and trade associations, as well as by several States, has resulted in significant changes to this schedule. The result of these changes has shifted the latest date for transfer of primacy or implementation of a Federal program from June 3, 1980 to January 3, 1981, and on-the-ground compliance from February 3, 1980 to September 3, 1981. Litigation pending in eight States (Pennsylvania, Virginia, Ohio, Tennessee, Kentucky, Alabama, Indiana, and Illinois) enjoining implementation of a Federal program in those States that did not gain primacy according to the schedule, has further delayed the implementation schedule. Although the full surface mining regulatory program was to have gone into effect on Federal lands 1 year after enactment of the statute (i.e., Aug. 3, 1978), the Secretary of the Interior, exercising his discretion, shifted the effective date of the permanent program requirements to coincide with the date on which primacy is transferred to a State or a Federal regulatory program is implemented for the State (Jan. 3, 1981).

Several other environmental statutes also affect the manner and method of mining coal on Federal leases. The most significant of these are the Clean Air Act and the Clean Water Act. Others, such as the Endangered Species Act of 1973, Bald Eagle Protection Act of 1969, as amended, Migratory Bird Treaty Act of 1918, as amended, the National Forest Management Act of 1976, and the National Historic Preservation Act of 1966, as amended, may act to prevent mining in certain locations at the mine plan approval stage. These acts are discussed separately later in this chapter. The DOI, in implementing the coal leasing process in accordance with the Federal Lands Policy and Management Act of 1976, has applied most of these statutory requirements to the process of selecting tracts for leasing during the land planning process, i.e., at the earliest stage in the lease development process. Because of the preliminary nature of the data available at this early point in the development process, decisions on certain criteria cannot be made concerning the suitability of a given tract for leasing, and these decisions are considered in the actual mine plan approval process.

In the West, because much of the coal reserve underlies Federal lands, OSM has had direct responsibility not only for enforcing the act's regulatory requirements, but also for issuing operating permits on specific mines. The responsibility for overseeing mining activities on Federal lands is shared by the U.S. Geological Survey (USGS), the Bureau of Land Management (BLM), and the U.S. Forest Service as well as with those Western States with Federal lands within their boundaries that have gained regulatory primacy and have signed cooperative agreements with DOI. USGS has jurisdiction over exploration on Federal lands outside mine permit areas, as well as responsibility for resource conservation, diligence, and royalties under the Mineral Leasing Act as discussed in greater detail in chapter 9 of this report, BLM is the leading agency for Federal minerals and, under a variety of Federal statutes, is responsible for the management and protection of surface resources on Federal lands. BLM can set postmining land use performance bond limits to assure protection of these resources. The Forest Service performs a similar role for National Forest System lands. Thus, USGS, BLM, and the Forest Service, together with OSM, submit recommendations to the Secretary of the Interior concerning the approval or disapproval of mine plan applications. The U.S. Department of Agriculture, acting through the U.S. Forest Service, must concur in the issuance of mine plan approvals for mines within the boundaries of any national forest. Applicable Federal, State, and local agencies retain similar authority with respect to mines that might adversely affect any public park or site included in the National Register of Historic Sites.

Each of the Western States with significant coal reserves had enacted surface mining legislation in the 1970's prior to passage of the Surface Mining Act. The stringency of the State programs varied significantly, with Wyoming and Montana generally recognized as having had the most stringent programs, and Utah and New Mexico the least stringent. All of the Western States have received approval of their permanent regulatory programs and have qualified for assumption of primary regulatory jurisdiction under SMCRA. Thus, the States have assumed primary responsibility for mine plan compliance and enforcement with the act's requirements. Those States with approved permanent plans that have entered into a cooperative agreement with the Secretary of the Interior acquire the authority to regulate mining on Federal lands within their boundaries. The Secretary of the Interior, however, retains the authority to approve or disapprove mining plans on Federal lands and to designate Federal lands unsuitable for mining.

The OSM regulatory program is in the process of undergoing changes. Secretary of the Interior James Watt has ordered major organizational and staff revisions for OSM. Proposed budgetary cuts for fiscal year 1982 decrease funding for oversight inspections of mines. Extensive review of existing regulations is expected to result in a significant decrease in the extent of current regulations and is expected to increase the use of guidance documents and handbooks to clarify SMCRA. Reliance on State enforcement programs is expected to increase significantly. In announcing a plan to reorganize the number of OSM offices outside of Washington, Secretary Watt said:

> As the States move closer to achieving primary responsibility for enforcing the Surface Mining Control and Reclamation Act of 1977, the role of the Office of Surface Mining is shifting to one of assistance, advice and review of state efforts to assure that the environmental protection standards of the Act are met. [3]

The reorganization plan and regulatory review has been critized by conservation and some agricultural groups and supported by the coal industry, The ultimate effect of these changes in the OSM regulatory program is uncertain at this time,

Selected Environmental Issue Areas and Their Relationship to the Development of Federal Coal

The following sections discuss several environmental issue areas: air resources,

‘U.S. Department of the Interior Press Release, May 21, 1981.

water resources, alluvial valley floors, topsoil and spoil handling, revegetation, wildlife, and cultural resources, and analyze how the enforcement of statutory controls may affect the production of Federal coal. Each section reviews the specific statutes important to that issue area, outlines the environmental concerns, and discusses the likely effect of these concerns on coal production. Emphasis is placed on limitations to recovery of coal reserves or on the rate of recovery. The general effect of environmental controls on mining costs is considered in the last section of this chapter.

Air Resources

Laws and regulations protecting air quality affect coal mining activities in three ways. First, mines must comply with national air standards as established by the Clean Air Act and various State implementation programs. Second, undeveloped leaseblocks whose development is contingent on mine-mouth* power generation or synthetic fuels development are affected if those facilities cannot comply with applicable local air quality standards. Lastly, changes in requirements for controlling sulfur emissions at powerplants in the market area for Western coal may affect the competitive cost advantages of low sulfur Western coal.** Issues related to direct emissions from mining activities are focused on fugitive dust and its effect on total suspended particulate (TSP). No other emission from coal mines is important to national or State air standards. Standards for sulfur dioxide ($S0_2$) and nitrogen dioxide (NO_2), as well as for TSP affect emissions from powerplants or synthetic fuel plants.

To date, air quality concerns related to direct mine emissions have had only a minor effect on Western coal mine development. In portions of the Powder River coal basin, fugitive dust emissions have exceeded or are nearing national ambient air standards, and mining activities in these areas may have to adopt better dust control measures. However, the level of production in this region is not expected to be constrained by air standards.

*Mine-mouth powerplant is a term that refers toa coal-fired electrical generating facility located at or near the supplying coal mine.

**This issue is examined in ch. 5.

Some mine-mouth powerplants may experience difficulty in receiving permits because of their inability to meet air quality regulations. Expanded development of some Federal mines in North Dakota may be delayed because of the projected impacts of new powerplants and synfuels projects on the pristine air of the Theodore Roosevelt National Memorial Park, a Class I clean air area. Similarly, powerplants or synthetic fuel plants may have difficulty meeting air standards in parts of the Powder River basin and in southern Utah. In some cases, notably in North Dakota, the quality of the coal that would fire the mine-mouth plants is too low to transport any distance. Thus, failure to gain air permits for major facilities could preclude development of some coal reserves. However, a final decision on permitting the proposed facilities in North Dakota has not yet been made.

The potential impact of changes in national sulfur emission standards on the development of Western coal is discussed in chapter 5, Markets. Generally, the requirement to control emissions regardless of the sulfur content of the coal decreases the competitiveness of low sulfur Western coal in market areas where local high sulfur coal is also available.

Statutory Control

Surface Mining Control and Reclamation Act

SMCRA requires that an operator: “stabilize and protect all surface areas including spoil piles affected by the surface coal mining and reclamation operation to effectively control erosion and attendant air . . . pollution" (sec. 515(b)(4)). Regulations adopted by OSM pursuant to this section required that an operator "plan and employ dust control measures as an integral part of site preparation, coal mining, and reclamation operations" (30 CFR 816.95(a) and 817.95(a)). These regulations listed 19 different control measures that might be employed by an operator to achieve the best available control of fugitive dust. However, these regulations were remanded to OSM by the decision of Judge Flannery of the district court of the District of Columbia.[4] The regulations, as promulgated, were said to be too encompassing and beyond statutory mandate. OSM has not proposed a revision of these performance standards and at this time is deferring to State regulatory agencies decisions about coal mine fugitive dust emissions. No date is available for reissuance of these OSM regulations.

Subsequent to this decision, each Western State except Montana remanded its State regulations that had mirrored the Federal regulations (30 CFR 816.95, 817.95). In each of these States, air resource issues are being handled by the State agency responsible for State implementation of the Clean Air Act Amendments and not by the mine reclamation agency. In Montana, coal mine related air resource issues are being handled jointly by the State reclamation agency and the State air quality agency. Even in Montana, where surface mine regulations are the strictest in the West, the standards of the Clean Air Act still take precedence. Thus, State implementation and enforcement of the Clean Air Act is the foundation of regulation of air impacts of coal mining.

Clean Air Act

The Clean Air Act establishes a national system of air quality regulation. Regulations and standards under this act are implemented at the Federal level by EPA and at State levels in conjunction with additional regulations and standards imposed by individual States. The following discussion highlights provisions of the act of significance to coal mining. Brief mention is also made of provisions of importance to mine-mouth facilities.

National Ambient Air Quality Standards (NAAQS)[5]

Regulation under the act focuses on six criteria pollutants: particulate, sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_x), ozone (O_3), and lead. Two types of ambient air quality standards are designated: primary standards, which were designed to protect human health; and secondary standards, which were designed to safeguard aspects of public welfare, including plant and animal life, visibility, and buildings. The Nation is divided into 247 air quality control regions (AQCRs) so that pollution control programs can be locally managed. Each AQCR is classified as to whether it meets the national standards.

The classification of an area with respect to ambient air quality has important consequences. Regions that are found by EPA to be in nonattainment status are subject to a particular set of restrictions under the act. On the other hand, nondegradation regions, where air is cleaner than the standards, are subject to a different set of regulations, which are intended for "prevention of significant deterioration" (PSD). Regardless of an area's classification, almost every new major source of emissions is required to undergo a preconstruction review. (A major source of emission is defined for PSD purpose at 40 CFR 52.2.l(b)(l)(i).)

To achieve air quality goals, areas with air cleaner than NAAQS were divided into classes I, II, and III. Certain national parks,

[4]In re Surface Mining Litigation, civil action No. 79-1144 (District of Columbia).

[5]The following discussion draws heavily from An Assessment of 011 Shale Technologies, OTA-M-1 18, June 1980. See also Final Rules on Requirement for State Implementation Plans for Prevention of Significant Deterioration, 45 F.R. 52676, Aug. 7, 1980. The rules implement major changes in Clean Air Act regulations required by the decision in Alabama Power Co. v. Costle, 13 E.R.C. 1225 (D.C. Cir. 1979]; 13 E.R.C. 1993 (D.C. Cir. 1979).

wilderness areas, and monuments that existed when the act was passed were immediately designated as class I areas where air quality is to remain virtually unchanged. All other clean air areas were designated class II—areas in which some additional air pollution and moderate industrial growth were allowed. Individual States or Indian Tribal governing bodies can redesignate some class II areas to class III areas in which major industrial development is foreseen and air pollution up to one-half the level of the secondary standards would be permitted. The States or Indian Tribes can also redesignate class II areas as class 1. Either type of redesignation is subject to hearings and consultations with the managers of affected Federal lands, or States in the case of Indian action.

State Implementation Plan (SIP)

Each State must submit an implementation plan for complying with primary and secondary standards. A State can decide how much to reduce existing pollution to allow for new industry and development. State plans must also include an enforceable permit program for regulating construction or operation of any new major stationary source in nonattainment areas, or significant modification to an existing facility. New processing plants and power stations must also satisfy emission standards set forth in the State implementation plan.

Each of the Western States has adopted its own ambient air quality standards (table 83). For particulate, Colorado has the strictest standards. For sulfur, important for powerplant emissions, Montana, North Dakota, and New Mexico have the strictest standards.

The Prevention of Significant Deterioration

All SIPS must specify emission limitations and other standards to prevent significant air quality deterioration in each region that has air quality better than primary or secondary NAAQS or cannot be classified with regard to compliance with primary standards because of insufficient information.

Under these PSD standards, maximum allowable increases in concentration of SO_2 and particulate are specified for each class (table 84). For the other criteria pollutants, maximum allowable concentrations for a specified period of exposure must not exceed the respective primary or secondary NAAQS, whichever is stricter.

A State can redesignate a class I or II clean air area with respect to PSD to allow greater increases in emissions under procedures set

Table 83.—Federal and State Ambient Air Quality Standards Pertinent to Coal Mine and Related Facility Development

	Concentration in micrograms per cubic meter							
Pollutant	Federal (primary)	Federal (secondary)	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming
SO_2								
Annual arithmetic mean .	80	—	80	53.3	53	53.3	80	60
24-hr maximum	365	—	365	267	267	267	365	260
3-hr maximum	—	1,300	700	1,334 (1 hr standard)	—	747 (1 hr standard)	—	1,300
Particulate:								
Annual geometric mean .	75	60	45	75	60		75	60
24-hr maximum	260	150	150	200	150	1%	260	150
NO_x (as NO_2)								
Annual arithmetic mean.	100	100	100	100 600 (3 hr standard)	100 200 (24 hr standard)	100 200 (1 hr standard)	100	100

[a] Standards for oxidants, CO, lead, and nonmethane hydrocarbons omitted.

SOURCE: Off Ice of Technology Assessment.

Table 84.—National Standards for Prevention of Significant Deterioration of Ambient Air Quality (concentration in micrograms per cubic meter, $\mu g/m^3$)

Averaging time	Maximum allowable increase Class I	Class II	Class III
Particulates:			
Annual	5	19	37
24 hour	10	37	75
SO_2:			
Annual	2	20	40
24 hour	5	91	182
3 hour	25	512	700

SOURCE Office of Technology Assessment.

forth in the act. These include an assessment of the impacts of the redesignation, public notice and hearings on such a redesignation, and approval by EPA. However, certain Federal areas cannot be redesignated.

If a facility's construction began after January 1, 1975, a special preconstruction review must be undertaken if it is located in a nondegradation area. To obtain a permit for such a facility, an applicant must demonstrate that it will not cause air pollution in excess of NAAQS or PSD standards more than once per year in any AQCR. Best available control technology (BACT) must be used for all pollutants regulated by the act, and the effects of the emissions from the facility on the ambient air quality in the areas of interest must be predicted. Impacts on air quality that could result from any growth associated with the facility must also be analyzed.

Although coal mines are not subject to PSD review under Federal regulation, State PSD permits are required for most coal mines in North Dakota and Montana. Under proposed State rules, PSD permits for coal mines in Wyoming may be required, but final administrative action has not yet been taken.

Implications of the Clean Air Act for Federal Coal Development

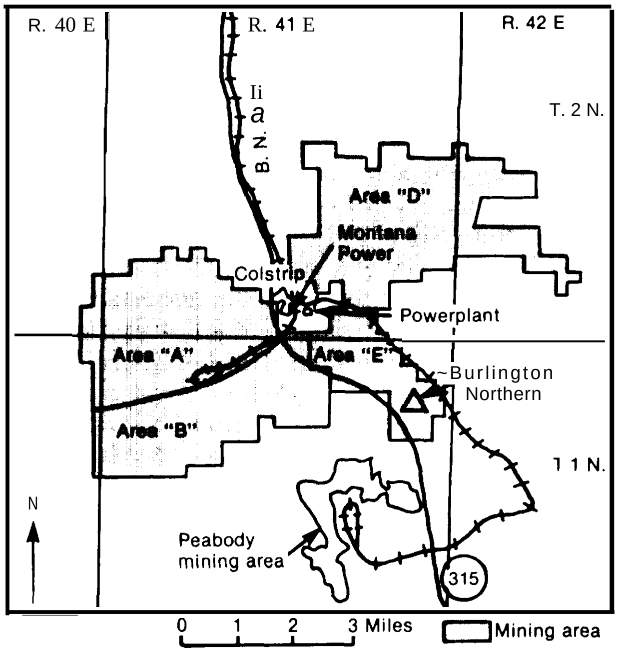
Fugitive dust emissions are the only type of coal mine emission that has the potential for violating national or State ambient air quality standards. Annual mean TSP concentrations have exceeded standards at Colstrip, Mont. in 5 of the last 6 years. Prior to 1974, the primary standard was not exceeded. In 1977, when the annual mean concentration for TSP at Colstrip was 92µg/ms, the next highest concentration was 48.1µg/ms, at Ekalaka in eastern Montana, A 120-mi^2 area surrounding Colstrip was designated as a nonattainment area in 1978 (fig. 44). Surface mining activities surrounding the town are considered the primary source of fugitive dust.

Ambient air quality standards have not yet been violated at Gillette, Wyo. However, the Wyoming standard for maximum 24-hour TSP concentration is reportedly being exceeded at some mines.[6]

Roads are the major source of fugitive dust from surface coal mining operations and generally are responsible for twice as many emissions as the next most important source. Other sources of fugitive dust include unit trains, coal storage and processing facilities, spoil piles, and reclamation areas. Options

[6] Personal communication with the Wyoming Department of Air Quality, Sheridan Office.

Figure 44.—Colstrip TSP Nonattainment Area



SOURCE: U.S. Geological Survey and Montana Department of State Lands, *Draft Environmental Statement for Proposed Expansion of Mining and Reclamation Plan, Big Sky Mine, 1978,* fig, 11-11 for controlling fugitive dust emissions include:

1. periodic watering of unpaved roads;
2. chemical stabilization of unpaved roads;
3. paving of roads;
4. enclosing, covering, watering, or otherwise treating haul trucks and railroad cars;
5. substituting conveyor systems for haul trucks;
6. minimizing the area of disturbed land;
7. prompt revegetation of regraded lands; and
8. covering coal storage areas.

Some of these options are employed at each surface mine in the West. Most mines in Campbell County, Wyo. pave their haul roads. Closed conveyor systems replace truck haulage at Gulf's McKinley Mine near Gallup, N. Mex., and at AMAX Coal's Belle Ayr Mine south of Gillette. All mines water haul roads and revegetate topsoil stockpiles. Many mines now enclose their coal storage areas.

Operations in Nonattainment Areas

The Colstrip, Mont. area has been designated a nonattainment area for TSP. In December 1979, Western Energy filed a petition against the nonattainment designation with the Montana Department of Health and Environmental Sciences and EPA. Monitoring data indicate that the TSP problem exists only in the immediate vicinity of Colstrip and not in the entire 120-mi^2 area. However, no redesignation has yet been made. T Criteria for approval of new facilities in nonattainment areas are subject to careful regulatory review. Sources of fugitive dust, most notably Western Energy's Rosebud Mine, must develop plans to limit emissions so that TSP concentrations will eventually meet standards. Also, no new facilities may be approved unless it can be shown that the new facility will not add to emissions in the area.

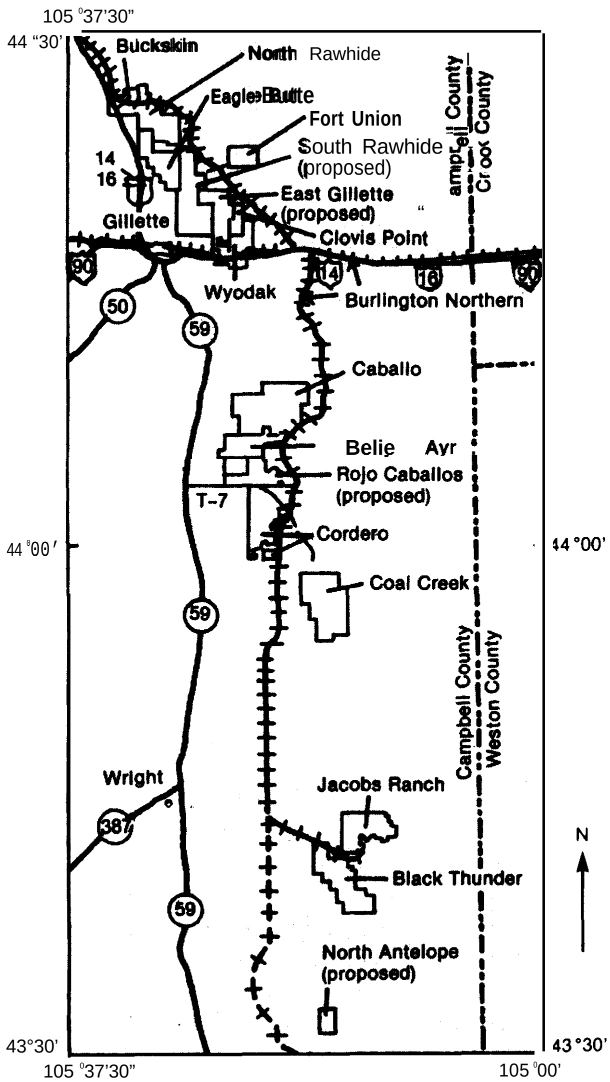
[7]Montana Department of State Lands, Final Environmental Impact Statement, Western Energy Company's Rosebud Mine, Area B Extension, 1980.

Western Energy has initiated measures to reduce emissions, including seeding of lawns in the town, paving of some roads, and chemical treatment of some haul roads. However, construction of two new powerplants in the town makes future compliance with TSP standards uncertain. As long as neither Peabody Coal, which operates the Big Sky Mine, also in the nonattainment area, nor Western Energy proposes increasing their current capacities, their future applications for extending their mines will probably not be affected. However, increasing capacities and construction of new facilities cannot be approved under SIP unless Western Energy can demonstrate reduction of other emissions such that emissions from expanded production will not increase total area emissions, Because Western Energy plans on extending capacity by 5 million tons per year in 1984, the company will have to either achieve other emission reductions by that time or gain a favorable decision on redesignation of the nonattainment area.

Operations in the Wyoming Portion of the Powder River Coal Basin

As noted, TSP levels in portions of the Powder River coal basin in Wyoming are approaching the limits set by State ambient standards. Already, mines are installing controls, including paving of many roads. However, the magnitude and concentration of mines make compliance difficult (fig. 45). In particular, north of Gillette, where the Buckskin, Rawhide, and Eagle Butte Mines are adjacent to one another, as well as to the undeveloped South Rawhide, Dry Fork, and East Gillette leaseholds, compliance with TSP standards at higher than existing production rates is of increasing concern. South of Gillette, the Caballo, Belle Ayr, Rojo Caballos, and Cordero Mines are adjacent to one another. Total 1979 production at these four mines was 20.1 million tons, but may expand to about 30 million tons in 1985 (see ch. 7). Although modeling of TSP concentrations has indicated compliance with standards at permitted production levels, OSM and Wyo-

Figure 45.— Lease Blocks in the Vicinity of Gillette, Wyo.



SOURCE: U S. Office of Surface Mining, *Draft Environmental Statement Proposed Mining and Reclamation Plan, Rojo Caballos Mine, 1980,* fig. 1-1.

ming Air Quality officials have expressed uncertainty about the accuracy of these modelling projections.[8] Expansion of mining at the Jacobs Ranch and Black Thunder Mines in southern Campbell County may increase local TSP concentrations in that area, as well.

If air quality standards are not met, portions of Campbell County could be designated nonattainment areas, despite prior issuance of air quality permits. Such designation would require development of mitigation programs and reevaluation of each operation's fugitive dust control plan. Although production rates would probably not be affected, additional control measures might be required.

Some new mines in Campbell County have not obtained approval of their proposed maximum production rate. For example, the Black Thunder Mine received a permit for a maximum production level of 20.5 million tons per year although it applied for a 30 million tons per year maximum rate. Modeling had indicated that production greater than 20.5 million tons per year would have resulted in emissions exceeding TSP standards. Black Thunder's planned production for 1991 is 20.5 million tons per year; it currently has to supply contracts 16.5 million tons per year in 1991. (See ch. 7.)

To date, Wyoming has issued permits for existing and proposed mines in Campbell and Converse counties that could accommodate over 250 million tons per year (table 85), This is three times total production from the entire Powder River basin in 1979 and is higher than OTA's high scenario estimate for coal production from all Federal mines in the entire Powder River basin, including the Montana portion, in 1991. Only three undeveloped Federal lease blocks in these two counties considered by OTA to have favorable production prospects for 1991 have not yet gained air permits (table 85). Each of these leases is expected to receive a permit for some level of production. Six Federal lease blocks have air permits in excess of their expected 1991 capacity and three lease blocks will have 1991 capacities in excess of air permits (table 85).

Under OTA's low demand scenario for the Powder River basin, only the Rochelle and Antelope lease blocks would need to acquire air permits to meet projected production levels. Permits are expected to be issued for both lease blocks. Under OTA's high demand scenario, the Buckskin, North Rochelle, South

[8] Personal communication to OTA, Wyoming Air Quality Bureau Staff, Sheridan.

Table 85.—Air Permits and Production Scenarios for Mines in Campbell and Converse Counties, Powder River Basin, Wyo.

Mine	Approved air permit	1991 capacity	1991 OTA high demand scenario production	1991 OTA low demand scenario production
Developed-Federal				
Buckskin	6	6.2	6.2	5.5
Rawhide	24	24	30.7	14.2
Eagle Butte	29	25	35.2	29.2
Wyodak	5	5	4.9	4.0
Caballo	12	12	included in Rawhide estimates	
Belle Ayr	25	11	included in Eagle Butte estimates	
Rojo Caballos	20	15	12.5	5.0
Cordero	24	24	20.5	9.7
Coal Creek	18	12	10.1	4.2
Jacobs Ranch	16	16	15.3	11.7
Black Thunder	20.5	20.5	19.4	14.6
Dave Johnston	[a]	3.8	3.8	3.3
Developed—non-Federal				
Fort Union	1.2	0	—	—
Clovis Point	4.0	5.0	—	—
Undeveloped-favorable development prospects Federal				
North Rochelle	—	8	5.9	0
Wildcat	10	7	5.1	0
South Rawhide	7	12	8.8	0
Dry Fork	15	8	5.9	0
East Gillette	11	15	11	0
Rochelle	—	6	6.0	5.3
North Antelope	5	5	5	4.4
Antelope	12[b]	8	8	7

[a] Air Quality permit is not required for this mine.
[b] Application under review.

SOURCE: Office of Technology Assessment. (Values for approved air permits are from the Wyoming Air Quality Bureau records. See ch. 7 of this report for mine capacities and a discussion of the OTA high and low demand scenarios)

Rawhide, Rochelle and Antelope blocks are expected to need air permits to accommodate higher production; between them, Buckskin and South Rawhide would need permits for 2.0 million tons per year of additional production under the OTA high demand scenario. Permits for capacities in excess of the expected capacity of 22 million tons per year at North Rochelle, Rochelle, and Antelope are expected to be issued.

implications for Onsite Powerplants and Synfuels Facilities

Lignite in North Dakota will be mined for consumption by local powerplants or synthetic fuel plants. Because of its low heat content and tendency to combust during transport, lignite is, with one exception, not shipped long distances. Future expansion of lignite mining in North Dakota is contingent on continued development of mine-mouth powerplants and synthetic fuel plants.

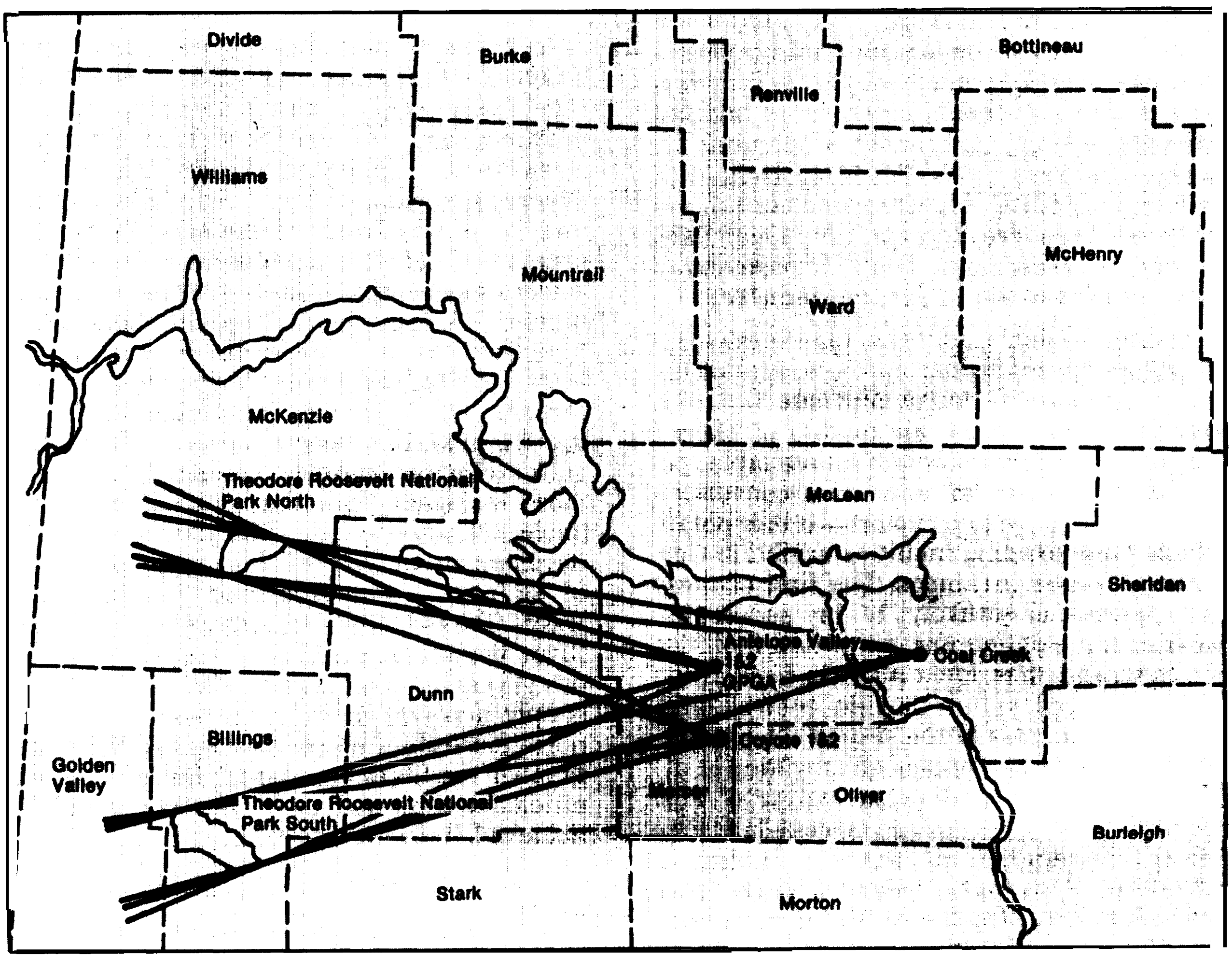
However, the prevention of significant deterioration (PSD) provisions of the Clean Air Act may delay or limit the future development of new power or synthetic fuels facilities in western North Dakota. Although there are no nonattainment areas in the State, the Lostwood Wilderness Area and the Theodore Roosevelt National Memorial Park are mandatory Federal class I areas.

Air quality monitoring and modeling conducted by the North Dakota State Department of Health suggests that available air quality increments of SO_2 at Theodore Roosevelt National Park may be exceeded if additional powerplants or synfuels facilities are permitted in west-central North Dakota. In 1978, using a model developed by EPA, the Department of Health obtained results that indicated that the operation of seven coal conversion units under review at that time would result in SO_2 concentrations that would exceed allowable standards for the national park.

These permit applications included United Power Association's Coal Creek units 1 and 2, Montana Dakota Utilities' Coyote No. 1 facility, Great Plains Gasification Associates' coal gasification plants, phase I and II, and Basin Electric's Antelope Valley Station units 1 and 2 (fig. 46). Because Basin Electric was the last organization to file a building permit application, the company had to redesign its plants to reduce SO_2 emissions. Basin Electric resubmitted its application and was subsequently granted permission to build. According to the model, the Basin Electric project left no room for additional concentrations of SO_2 at the park.

Based on the results of their modeling, the North Dakota State Department of Health has not granted any additional permits, beyond the seven listed above, for construction of new coal conversion facilities east of the park. Although powerplant operators have maintained that the EPA model used to estimate remaining SO_2 increments at Theodore

Figure 46.—Relationship of Recently Permitted (1979) Sources to the Theodore Roosevelt National Park (wind flow vectors indicated)



SOURCE: U.S Bureau of Land Management, Final *West-Central North Dakota Regional Environmental Impact Statement* on *Energy Development, 1978.*

Roosevelt National Park is not reliable beyond distances of 50 to 70 kilometers, no alternative modeling data has yet been found acceptable by the State. Most of the development in Mercer and Oliver Counties is taking place more than 150 kilometers from the park. Work on improving modeling techniques is currently underway at the North Dakota Department of Health.

The coal industry must also compete with expansion of oil and gas production for air quality increments. Because North Dakota's Western oil and natural gas resource areas overlap the Fort Union lignite region, gas extraction and refining facilities located near Theodore Roosevelt National Park would compete directly with coal development for any available sulfur dioxide increments. In general, oil and natural gas production would not involve major air quality considerations; however, much of the gas in this area is sour (i.e., contains up to 24 percent hydrogen sulfide) and presents potential air quality problems when flared or treated in sweetening plants. If additional class I increments at Theodore Roosevelt National Park become available, some could be assigned to the expansion of the natural gas industry.

At some point, additional lignite development may be dependent on the ability of lignite consumers to design and site facilities that do not affect the air quality of class I areas. If increments remain unavailable, potential developers of new coal conversion facilities will have two choices—either obtain offsets from existing facilities or obtain Government-issued variances. The first of these two options is unlikely to be successful. Most of the existing and permitted facilities are new and thus have already been fitted with advanced sulfur dioxide control techniques. In the case of the second alternative, the State so far has appeared unwilling to exercise its authority allowing waiver of PSD requirements under certain circumstances to permit degradation of the air quality of Theodore Roosevelt National Park. Proposed facilities affected by the situation are listed in table 86, However, the situation remains unresolved. Considerable uncertainty stems from the fact that five permitted facilities have not yet been built and therefore their effect on air quality can only be estimated.

Table 86.—North Dakota Department of Health Pending Air Emissions Permits

Company	Operation	Type	Capacity
Nakota	Unnamed	Coal to methanol	96,000 bbl/d
Basin Electric	AVS III	Powerplant	500 MW
Basin Electric	Sunrise	Powerplant	1,000 MW
Warren Petroleum		Sour gas treatment	30 MCF/d
AMOCO		Sour gas treatment	100 MCF/d
Minnesota Power & Light		Powerplant	1,000 MW

SOURCE: Office of Technology Assessment.

In Wyoming, class I designations and State sulfur standards may also affect onsite facilities construction. Class I areas have been proposed both for the Cloud Peak Primitive Area in the Bighorn Mountains west of the Wyoming portion of the Powder River basin and for Devils Tower to the east. State governments and Tribal governing bodies are solely responsible for making such a redesignation determination. Air quality considerations may constrain the eventual level of synfuels development in the Powder River basin and southern Wyoming, but probably not during the next 10 years. However, Wyoming's sulfur dioxide emission standard, which is more stringent than the national standard (table 83) could create difficulties for onsite development of coal reserves with high levels of sulfur. Two undeveloped Federal lease tracts (the Belco tract in the western Powder River basin and the Cherokee tract in southern Wyoming) that have reserves sufficient to supply a power or synfuels plant would require more than 95 percent sulfur reduction to meet the State standard. * Sulfur removal efficiencies exceeding 95 percent could be achieved, but would be expensive.

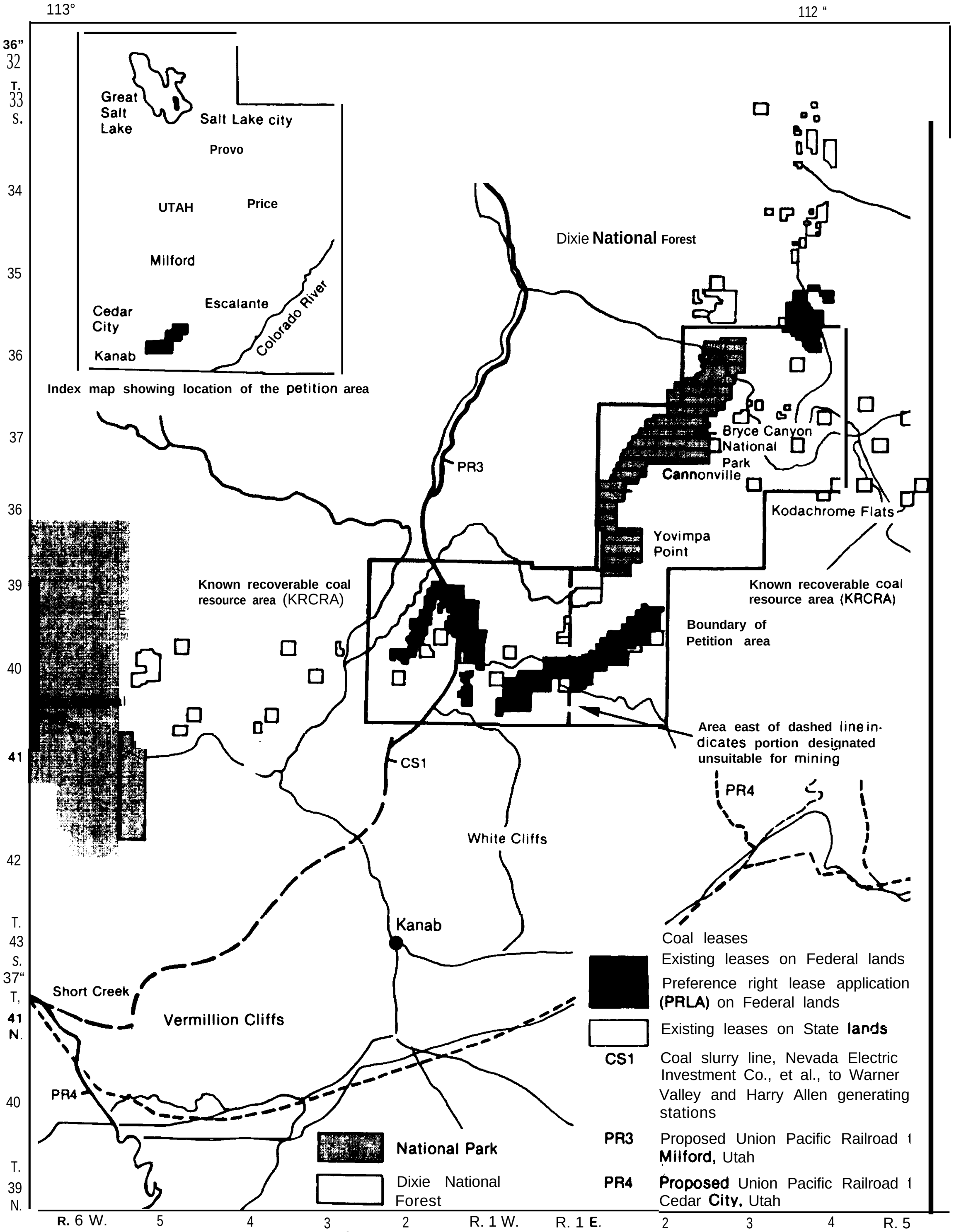
*The Belco tract is expected to be traded for other Federal coal lands under provisions of Public Law 95-554.

Air Quality Issues and the SMCRA Unsuitability Petition Process

Under the SMCRA unsuitability petition process, areas may be designated unsuitable for coal mining if it can be shown that mining operations will "affect fragile . . . lands with significant damage to important. . . aesthetic values or natural systems" (30 CFR 762.11(b)(2)). In the Alton coalfield of southern Utah, an area including 28 undeveloped Federal leases covering 26,693 acres (fig. 47), several petitioners, including local landowners and three national conservation groups, alleged, among other things, that the visibility and air quality values from and within Bryce Canyon National Park would be threatened by coal mining. (The park is a mandatory class I attainment area under the Clean Air Act.) The OSM's analysis of these allegations used PSD standards as an evaluative benchmark.[9] OSM found that 24-hour PSD class I increments could be exceeded one or two times a year in a small portion of the park. OSM also found that visibility would be locally reduced by dust plumes from mining and coal trucks. There was conflicting data from other sources that PSD increments would not be exceeded. The final decision by the Secretary of the Interior to designate 9,049 Federal lease acres of the proposed petition area as unsuitable was based on the finding that mining in part of the area would impair scenic vistas visible from the park and that high noise levels would occur in some areas within the park, thus damaging the values for which the park was established.

"See U.S. Department of the Interior, Statement of Reasons Supporting Secretarial Decision on Petition to Designate Certain Federal Lands in Southern Utah Unsuitable for Surface Coal Mining operation, Jan. 13, 1981, OSM ref. No, 79-5-001, pp. 13-14.

Figure 47.—Map of Southern Utah Petition Area Showing Federal and State Coal Leases, Coal-Slurry Pipeline Route, and Proposed Coal Haul Railroad Routes



SOURCE: U.S. Office of Surface Mining, *Southern Utah Petition Evaluation Document,* 19S0, fig. 1A-1.

Water Resources

Water is a scarce and valuable commodity in the West and concern for the water resource is indicated in detailed Federal and State regulations. Ground and surface water hydrology data required of proposed coal mine operators is more extensive than any other type of data.

Several aspects of the water resource issue could affect Federal coal development. However, none has yet resulted in disapproval of a mine plan. Potential for selected prohibitions exists in cases where water supply diminution or degradation becomes unavoidable, and alternative supplies cannot be identified. Conflicts with other water users exist in virtually every coal region; this study has not attempted to analyze these conflicts in any detail.

Water resource concerns could result in the prohibition of mining in some areas under the unsuitability petition process. These concerns were part of the Alton coalfield petition but were not critical to the final secretarial decision, because insufficient information was available on which to make a determination. The decision noted that the hydrological impacts of proposed mining operations would be reviewed when a mine plan was submitted for approval under SMCRA.[10] Water resource concerns are central to a recently filed petition for a part of the Tongue River drainage basin in southeastern Montana (see also ch. 9).

The availability of water for use by mines, particularly where irrigation is necessary for reclamation in the Green River-Hams Fork and San Juan River regions may ultimately constrain coal development. However, OTA did not identify any areas where such a constraint was imminent.

[10] Ibid, The Alton lessees submitted a mine plan for the Project before SMCRA regulations were implemented. The mine plan has not been updated to incorporate additional surface mining permit requirements.

The extent of regulatory control over water resource issues has been the subject of criticism from the coal mining industry. These criticisms are identified and summarized in this section; however, a detailed study of increased costs and time delays attributed to these regulations is beyond the scope of this report.

General Impact of Coal Mining on Water Resources

Coal mining activities affect water both directly through disturbance by mining, indirectly through powerplant facility development, and potentially through transportation by coal slurry pipelines. Primary attention has centered on the direct impact of surface mining, particularly on disruption of ground water flow and quality. Recently, research has begun on the impacts of underground mining and related subsidence on water resources.

The opening of a pit for surface mining affects the level and flow of ground waters. The mine pit will intercept all ground waters that are found above the pit floor. Directions of ground water movement may change and even reverse as water surrounding the pit in all directions flows toward the pit. As water flows into the pit, water levels in surrounding areas, as evidenced in wells, will fall. Ultimately, an equilibrium condition is established based on the characteristics of the water-transmitting rocks (aquifers) and the length of time the pits are open. Monitoring studies have measured the offsite extent of drawdown, as the lowering of the ground water level is termed, 2 miles from an active pit.[11]

Water quality can also be affected. Ground water moving through backfilled

[11] Van Voast and Hedges, Hydrologic Aspects of Existing and Proposed Strip Coal Mines Near Decker, Southeastern Montana: Montana Bureau of Mines and Geology Bulletin 97.1975.

surface mines is known to have substantially increased concentrations of total dissolved solids and other constituents. Generally, the average concentration of dissolved solids is two to three times greater in spoil waters than in the waters in undisturbed coal aquifers.

The overall potential changes are such that Congress, OSM, and the various States have developed comprehensive requirements for the prediction and monitoring of ground water impacts from surface mines.

Impacts of sedimentation and pollution on surface waters are more easily understood and monitored. The primary impact, increased sediment loads in streams caused by erosion of mine and reclamation areas, can effectively be controlled by construction of sedimentation ponds at drainage outlets from mines. Surface waters can also be affected by seepage of polluted ground waters into receiving streams. Although not observed to date, this possibility is the basis of the Northern Plains Resource Council unsuitability petititon for the Tongue River area. The petition is partly based on a published modeling study predicting this impact.

Subsidence from underground coal mining has been documented to impact water resources and the subject is receiving increasing study. Subsidence cracks have caused interception of spring flow, ground water flow, and stream flow at locations in the Uinta-Southwestern Utah coal region.[13] Since subsidence is an expected aspect of all underground mining, regulatory concern over associated environmental impacts is growing. Subsidence monitoring has been required at several underground mines as a condition of permit approval.

[12]Woessner, Osborne, Heffern, Whitman, Spotted Elk, and Morales-Brink, *Hydrologic Impacts from Potential Coal Strip Mining, Northern Cheyenne Reservation*, report to the EPA Industrial Environmental Research Laboratory, Cincinnati, Ohio, 1980.

[13]Dunrud, *Some Engineering Geologic Factors Controlling Coal Mine Subsidence in Utah and Colorado*, USGS Professional Paper 969, 1976.

Powerplants and synthetic fuel plants are affected by Clean Water Act provisions relating to discharge limitations. Effluent standards are not a significant impediment to construction of these facilities, however. The availability of water and restrictions on water usage under interstate water use compacts and State law have affected the construction of coal slurry pipelines and, to some extent, the construction of powerplants,

Statutory Control

Major regulatory review of the water resource impacts of mining proposals is conducted under the mandate of the SMCRA and the Clean Water Act. Water resource data is a major component of a mine permit application and compliance with several water resource performance standards must be demonstrated before an application can be approved. Mines must also obtain a permit to discharge effluents from an operation under provisions of the Clean Water Act. Thus, the agencies most responsible for review of water resource impacts are OSM and companion State reclamation agencies and EPA and companion State water quality agencies. The following section reviews some Federal statutes and regulations over water resources. Implementation in each of the Western States varies slightly and may be more stringent than outlined here. No State has less stringent provisions.

The SMCRA establishes conditions for permit approval or denial:

> No permit or revision application shall be approved unless the application affirmatively demonstrates and the regulatory authority finds in writing , . . that:
>
> (3) the assessment of the probable cumulative impact of all anticipated mining in the area on the hydrologic balance . . . has been made by the regulatory authority and the proposed operation thereof has been designed to prevent material damage to hydrologic balance outside the permit area (sec. 510b.)

Section 515(b) of SMCRA also establishes performance standards related to water resource impacts. A permit application must demonstrate, among other things, that these standards can be complied with before approval is obtained:

> General performance standards shall be applicable to all coal mining and reclamation operations and shall require the operation, as a minimum to—
>
> (2) restore the land affected to a condition capable of supporting the uses which it was capable of supporting prior to any mining, or higher or better uses of which there is reasonable likelihood, so long as such use or uses do not . . . pose any actual or probable threat of water dimunition or pollution . . . .
>
> (4) stabilize and protect all surface areas including spoil piles affected by the surface mining and reclamation operation to effectively control erosion and attendant . . . water pollution , . .
>
> (8) create, if authorized in the approved mining and reclamation plan and permit, permanent impoundments of water on mining sites as part of reclamation activities , . .
>
> (lo) minimize the disturbances to the prevailing hydrologic balance at the mine-site and in associated offsite areas and to the quality and quantity of water in surface and ground water systems both during and after surface coal mining operations and during reclamation by—
>
> (A) avoiding acid or other toxic mine drainage . . .
>
> (B)(i) conducting surface coal mining operations so as to prevent, to the extent possible using the best technology currently available, additional contributions of suspended solids to streamflow, or runoff outside the permit area, but in no event shall contributions be in excess of requirements set by applicable State or Federal law;
>
> (ii) constructing any siltation structures . . . prior to commencement of surface coal mining operations . . .
>
> (C) cleaning out and removing temporary or large settling ponds or other siltation structures from drainways after disturbed areas are revegetated and stabilized; and depositing the silt and debris at a site and in a manner approved by the regulatory authority;
>
> (D) restoring recharge capacity of the mined area to approximate premining conditions;
>
> (E) avoiding channel deepening or enlargement in operations requiring the discharge of water from mines , . .
>
> (G) such other actions as the regulatory authority may prescribe . . .

The purpose of these requirements is to ensure that long- and short-term adverse changes in the hydrologic regime that might be caused by coal mining and reclamation activities will be prevented or minimized.

OSM promulgated comprehensive regulations pursuant to these statutory provisions. The major subject areas of the regulations of concern to Western mining are:

- water quality standards and effluent limitations,
- diversions, sediment control, and sedimentation ponds,
- impoundments,
- protection of ground water and ground water recharge capacity,
- monitoring,
- water rights, and
- stream buffer zones.

Additional regulations concern alluvial valley floors; these provisions are discussed in a later section.

Water Quality Standards and Effluent Limitations

Control of discharges from mining and reclamation activities is jointly controlled by OSM and the agency responsible for implementation of the Clean Water Act in each State. Under sections 301, 304, and 401 of

84-141 0 - 81 - 20 : QL 3

the Clean Water Act, mining operations must obtain discharge permits and comply with EPA, or State effluent, limitations for point source discharges of pollutants to surface waters. However, the Clean Water Act permit system applies only during the active phase of mining; it does not extend to reclamation, nor does it cover nonpoint pollution sources, nor does it consider discharges to ground water. However, under SMCRA all water discharged as a result of coal mining and reclamation activities which could materially damage the hydrologic system is regulated. Thus, coal mines must obtain a permit to discharge from EPA, or administering State water quality agency, for all point source discharges. These discharges include effluents from plant facilities and discharge of ground waters intercepted in a mine pit. OSM, or State reclamation agency, review also considers other types of discharges such as those from reclamation areas, as well as providing input in the review of point source discharges.

Effluent limitations established by OSM are generally similar to those adopted by EPA (table 87). In each State, any stricter standards supersede these Western regional standards. For instance, the Montana State implementation program of the Clean Water Act includes a provision that no discharge may degrade the quality of receiving waters, regardless of conformance with specific effluent limitations. At most Montana coal mines, the necessity to meet this criterion is a stricter one than are the direct effluent limitations.

Table 87.—Effluent Limitations for Western Coal Mines in Milligrams per Liter (mg/l)[a]

Effluent characteristics	Maximum allowable	Average of daily values for 30 consecutive discharge days
Iron, total	7.0	3.5
Manganese, total	4.0	2.0
Total suspended solids	45.0	30.0

[a]EPA has proposed a relaxation of these effluent standards (46 F.R. 28873, May 29, 1961). OSM has proposed to adopt these relaxed standards (46 F.R. 34764, July 2, 1961).

SOURCE: 30 CFR 616.42(a)(7).

Diversions, Sediment Control, and Sedimentation Ponds

Sedimentation ponds in conjunction with other sediment control measures, are considered by OSM to be the "best technology currently available" to prevent offsite sediment increases, as required by SMCRA. Generally, OSM and State reclamation agencies require that ponds be constructed on drainages below all mining and reclamation disturbance areas. Regulations establish many of the design characteristics of these ponds, including their sediment storage volume, detention time, dewatering devices, methods to prevent short circuits, * spillway design, sediment removal, freeboard,** and engineering characteristics of the retaining dam.

In conjunction with sedimentation ponds, OSM regulations require sediment control measures within and around disturbed areas. These measures include:

- disturbing the smallest area practicable at any one time during mining,
- stabilizing pit backfill material,
- diverting runoff away from disturbed areas,
- use of mulches, and
- chemical treatments

Many of the design specifications of diversions are also outlined in regulation.

Impoundments

Regulations also establish minimum standards for permanent and temporary impoundments. These impoundments include any lakes or ponds proposed to become part of a reclamation landscape. Section 515(b)(8) of SMCRA establishes that permanent impoundments may only be constructed if six criteria are met:

- that the impoundment size is adequate for its intended purpose;

*Short circuiting: a process which transports sediment through a pond in less than the detention time necessary for the sediment to settle out.

**Freeboard: the height above the water surface level when the spillway is operating at design capacity.

- that the impoundment dam is designed to achieve necessary stability;
- that the quality of impounded water will be adequate for its intended use;
- that the impoundment water level will be reasonably stable;
- that water users will be provided adequate safety and access; and
- that adjacent landowners will not be adversely-affected by the impoundment.

Adopted regulations establish design criteria for impoundments and dams, and require inspections, maintenance, and initial certification.

Protection of Ground Water and Ground Water Recharge Capacity

SMCRA requires that the ground water portion of the hydrologic system be protected along with the surface water portion. Regulations have been adopted which generally require that backfilling and alinement of excavations be conducted so as to protect ground water outside the permit area.

SMCRA also requires that the recharge capacity of the mined area be restored to the approximate premining condition. Conceptually, recharge capacity is the ability of the soil and rock materials to receive water, store it for a period of time, and slowly release it, either to a topographically lower stream or lake, or to a well. Primarily, the movement of precipitation and surface water into the soil or rock materials is controlled by the infiltration capacity of those materials. Mining and reclamation have the potential of changing infiltration capacity, primarily through compaction.

Monitoring

Operators are required under SMCRA to monitor ground water and surface water quantity and quality on the permit area and in the surrounding area before, during, and after mining. The extent of the required monitoring varies, but must be sufficient to describe the premining environment and to provide enough data for evaluating the effects of mining and reclamation activities. Monitoring is required of all ground or surface waters which may be disrupted or degraded by mining.

Water Rights

Water rights issues are considered in the context of the State laws applicable in each State. OSM had developed regulations on the water rights issue; however, these were remanded in the Flannery decision (see p. 283), Generally, in each State, coal mining operations must replace any water supplies expected to be degraded or diminished by those activities.

Stream Buffer Zones

Disturbance of a perennial stream must be specifically approved under SMCRA. The regulatory authority must find that the stream channel will be restored and that undisturbed portions of the channel will not be affected.

Implications of Water Resource Issues for Federal Coal Development

Although no mine has yet been prohibited from operating because of conflicts with other water users, the potential for conflicts with municipal, domestic or agricultural water users exists. Conflicts may be acute in the Uinta-Southwestern Utah region. In all Western States, water supplies diminished or degraded by mining are required to be replaced by the operator. In many cases, mines choose to redrill nearby wells to deeper aquifers if impacts from mining are expected. The following discussion gives several illustrative examples of existing or potential conflicts.

Municipal and Domestic Impacts

Surface and ground water originating in the Wasatch Plateau of central Utah is used by several municipalities. Local water users are concerned that these waters may be intercepted or contaminated by underground coal mining along the eastern edge of the plateau. For instance, the town of Huntington, located near an active mining area, uses spring flow for its water supply. This spring flow may be affected by nearby underground coal mining. In the nearby Emery coal field, the town of Emery uses ground water that could be affected by Consolidation Coal's Emery underground mine and proposed surface mine. The effects of this mining are being studied by the company and USGS.[14] If mining were demonstrated to adversely affect municipal water supplies, mining companies would be required to replace these supplies or limit their mining areas.

In North Dakota, some lignite seams are significant aquifers. The Falkirk Mine is mining such a seam, which is also the water source for the nearby town of Underwood. Little data are yet available on the impacts of continued mining; however, the operator has made a commitment to provide alternative supplies should disruption occur.

Agricultural Impacts

The North Fork Gunnison River Valley of west-central Colorado is an area where underground coal mining may affect the availability of water for agricultural irrigation. Projected subsidence at the proposed Mt. Gunnison Mine may divert enough surface and ground water flow to adversely affect downstream water users.[15] The State reclamation agency and OSM are advising the operator that if this occurs, the company will have to purchase or replace the affected senior water rights in the valley. Otherwise, the mining company may have to leave recoverable coal in place in order to avoid subsidence and undesired water loss. Other mines in the Somerset coal field may face similar situations if projections of subsidence indicate diversion of significant surface flow.

Concern about the effect of underground mine-induced subsidence on springs is widespread in the Wasatch Plateau. A landowner above Utah Power & Light's Deer Creek Mine has expressed concern about subsidence effects on his springs, and the company has instituted a subsidence monitoring program to evaluate impacts. All operating or proposed mines in this area are developing monitoring programs to measure subsidence and impacts to springs and surface waters.

At the non-Federal Absaloka Mine in southeastern Montana in the Powder River basin, controversy about the projected destruction by surface mining of several seeps and springs has caused the operator, Westmoreland Coal, to delay proposing mining of the presumed source area of most of the springs. The State reclamation agency hopes that continued monitoring will result in a better understanding of the hydrologic system before mining is proposed for the recharge area itself.

Throughout the Fort Union region and Powder River coal basin, numerous domestic and stock wells obtain water from shallow aquifers. For example, 60 to 70 percent of western North Dakota's domestic and stock wells tap shallow lignite aquifers. Each of these water sources, if destroyed, diminished, or degraded by mining activities, is required to be replaced.

Empire Energy Co. is proposing to mine several seams below the Yampa River in northwestern Colorado in the Green River-Hams Fork coal region. Regulatory review is focused on the projected effect of mine-induced subsidence on the river, both in terms of environmental, and health and safety impacts.

Water Resource Issues and the SMCRA Unsuitability Petition Process

The effects of projected mining on water availability were part of the Alton coalfield unsuitability petition. The petitioners alleged that water development necessary to mine and transport coal, and to help reestab-

[14] Morrissey, Lines, and Bartholoma, Three-Dimensional Digital-Computer Model of the Ferron Sandstone Aquifer near Emery, Utah, USGS open file report.

[15] Personal Communication to OTA, Technical Analysis Division, Regional Director, Region V, OSM, 1981.

lish vegetation, would result in the drying of springs and stream recharge critical to agricultural water users in the same area. OSM found that "present users of . . . water . . . would be adversely affected.''[16] In making his final decision on the petition, however, the Secretary of the Interior found that insufficient information was available on this issue on which to exclude areas from mining and that the issue would be reexamined at the time of mine plan permit review.

The Northern Plains Resource Council and several affiliates have filed a petition for designation of lands unsuitable for mining for a portion of the Tongue River drainage basin in southeastern Montana. Unleased Federal coal, as well as fee and State coal reserves, are affected by the petition. In part, the petitioners claim that large-scale mining would have significant regional impacts on water resources. They claim that large-scale mining would have long-term degrading effects on the stream, adversely affecting stock and irrigation water uses. Because the effects would be experienced over a long time period, they fear that significant degradation could take place and not be identified until it was too late to initiate remedial measures. The petition is presently under review and a decision is expected by the State of Montana in late 1981.[17]

Other Water Resource Issues

Most of the water resource issues outlined in the discussion on statutory control have had no effect on the amount of Federal coal permitted for mining. Although some of the provisions have received substantial criticism from industry as being needlessly detailed and requiring unnecessary environmental protection, no Federal reserves have been prohibited from recovery because of these regulations. The issues of cost and time delay in collecting required information are briefly considered at the end of this chapter, although a detailed examination of these issues was not undertaken in this report.

Water quality standards and effluent limitations have not had an effect on the outcome of the permitting process. EPA and OSM limitations are able to be met at all Western mines. Some controversy has continued over the standard for total suspended solids, which industry has claimed to be too stringent. These standards are being revised to control total settleable solids, but the new standards have not yet been released. Industry has criticized the number and size of sedimentation ponds required of coal mines. These criticisms center around issues of increased costs. Construction of these ponds, particularly in steep canyons of the Uinta-Southwestern Utah region, has caused extensive disturbance at some areas.

To date, no permanent impoundment has been proposed under OSM regulatory program in the West. This may be because of regulatory constraints or because no impoundment has been needed for reclamation. The requirement to reestablish recharge capacity has not caused any regulatory denials; however, permit approval has been delayed in some cases because the data submitted was found to be insufficient. Monitoring requirements have been criticized as being overly demanding. However, in general, companies have apparently been able to bear these costs. The impact of these requirements on small operators is discussed in the final part of this chapter, Mining near perennial streams is generally approved under special conditions. Mining of perennial streams themselves has not generally been approved.

Water Availability: Primary and Secondary Impacts

Limited water supplies, and competition for those supplies, may ultimately affect the extent of coal mining development in por-

[16] U.S. Office of Surface Mining, Southern Utah Petition Evaluation Document, Document Nos. OSM-PE-1 and OSM-EIS-4, 1980.

[17] Northern Plains Resource Council, *Petition for Designation of Certain Lands Unsuitable for Mining*, 1980.

tions of the Green River-Hams Fork region and in the San Juan River region. In these water-deficit areas, mines need water not only for dust control and use in the facilities, but also for irrigation of vegetation on reclaimed areas. Irrigation is presently used at some mines in the Green River-Hams Fork region and all mines in the San Juan River region. Recent studies in southern Wyoming of expanded coal leasing indicate that water shortages are possible as mines, growing municipalities, and agriculture compete for the same water sources.[18]

Expansion of mining in the San Juan River region may also be affected by limited water availability. Essentially, surface water is nonexistent in this area and wells must supply all water needs. However, the Fruitland formation aquifer is expected to be the primary water supply for the uranium mining industry in the area, as well as for municipalities. According to the OTA New Mexico task force, if both industries expand in the 1980's, available water supplies may not be able to meet demands.

Water availability may also affect coal development where coal development is dependent on onsite powerplants, synthetic fuel plants, or slurry pipelines. See table 88 for water requirements for these facilities. Scarcity of water in the Gillette area of the Powder River basin justified the expense of constructing the first dry-cooling tower in the United States at the Wyodak Power Plant east of Gillette. Proposed sources of water for slurry pipelines have been the Madison Limestone aquifer and the Little Bighorn River. Controversy surrounds the use of either source. Although Energy Transportation Systems, Inc. (ETSI) has a permit from the State of Wyoming to withdraw about 20,000 acre-ft/yr from the Madison for its pipeline, the State of South Dakota is considering bringing suit against such a water use, claiming adverse impact to its existing uses of the same aquifer. The State of Montana has decided that use of water for slurry pipelines is specifically not a beneficial use of water and water use permits therefore cannot be granted for use of Montana water in coal slurry pipelines.

[18] U.S. Bureau of Land Management. Final Green River-Hams Fork Regional Coal Environmental Impact Statement, 1980.

Table 88.—Total Water Requirements for Various Major Facilities, Northern Great Plains

Facility	Water need (acre-feet/yr)
Water-cooled 1,000 MW powerplant (about 4 million tons per year)	10,000-15,000
275 million scf/d coal gasification plant.	4,500- 8,000
Slurry pipeline (35 million tons per year).	13,000-20,000

SOURCE: Office of Technology Assessment.

Alluvial Valley Floors

Under provisions of SMCRA, alluvial valley floors in the Western United States are given special protection because of their agricultural and hydrologic importance. The more important alluvial valley floors are protected from coal mining and its associated disturbance. The less important alluvial valleys may be mined, but standards for reclamation are higher than for other types of mined areas. The impact of the alluvial valley floor statutory provisions, adopted regulations, and guidelines have been the subject of continued debate among industry and regulating Government agencies. Industry has claimed that the alluvial valley floor provisions are overly complex, lead to significant delays in processing permits, and may ultimately lead to significant loss of recoverable reserves.

Analysis by OTA has found that:

1. To date, for Federal mines, only one stream valley in the West (Squirrel Creek Valley in Montana) has been identified as having the characteristics that will probably lead to absolute prohibi-

tion of mining activities in a portion of the valley. The affected companies have asked that this decision be reconsidered.

2. Numerous stream valleys in the Powder River coal basin have been, or are likely to be, identified as having characteristics that will allow mining, but under stringent alluvial valley floor reclamation standards.
3. Neither OSM, nor any State reclamation authority, has approved a proposed reclamation plan for an alluvial valley floor under the permanent regulatory program. Thus, no regulatory decisions have yet been made on which to analyze the detail and expense that reclamation of alluvial valley floors will necessitate. The general perception of both industry and Government officials is that most alluvial valley floors are reclaimable under existing technologies. Subirrigated alluvial valley floors pose the greatest difficulties for reclamation.
4. Alluvial valley floors have been identified under formal regulatory processes in the Powder River coal basin, and most leaseblocks in that basin are expected to include some areas of designated alluvial valley floor, Alluvial valley floors are also important in the Fort Union coal region. In the Green River-Hams Fork coal region and the Uinta-Southwest Utah coal region few alluvial valley floors have been identified,
5. The alluvial valley floor issue has the potential to affect more tonnage of recoverable coal than any other environmental factor. However, in relation to the total Federal recoverable coal base under lease, and the market supply relationships anticipated to exist until 1991, no adverse production effects are expected in the next 10 years.
6. Alluvial valley floor issues are likely to affect non-Federal coal reserves to a greater degree than Federal reserves because of the concentration of non-Federal coal in major river valleys, the sites of initial homesteading in the West.

Background and Statutory Control

As a general description, alluvial valley floors are those stream valleys in the western United States which: 1) are underlain by unconsolidated gravel, sand, silt, and clay; 2) have a stream flowing through them; 3) have a generally flat valley floor topographic surface; and 4) have an agricultural importance (fig. 48). The relative importance of these valleys is a function of the water supplies available in the specific valley area. The agricultural activities generally include irrigated or subirrigated hay lands, developed pasture lands, critically important grazing areas, or lands that could be developed for any of these purposes.

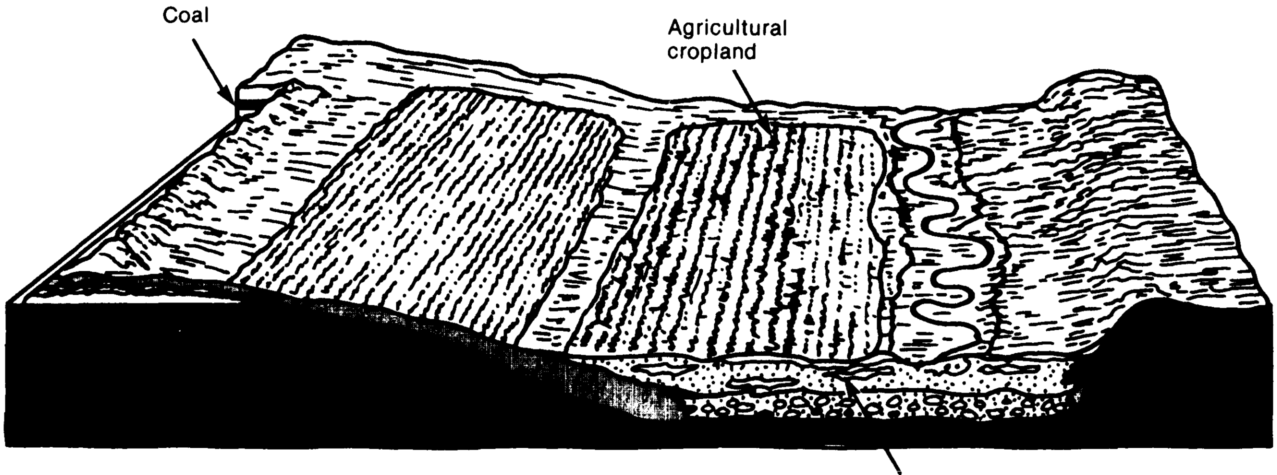
Alluvial valley floors were one of the more controversial portions of SMRCA, and were extensively debated in Congress prior to passage of the act in 1977. The special role that alluvial valley floors play in Western agriculture was central to the debate:

> Of special importance in the arid and semiarid coal mining areas are alluvial valley floors, which are the productive lands that form the backbone of the agricultural and cattle ranching economy in these areas, For instance, in the Powder River basin of eastern Montana and Wyoming, agricultural and ranching operations which form the basis of the existing economic system of the region could not survive without hay production from the naturally subirrigated and flood-irrigated meadows located on the alluvial valley floors.[19]

The provisions passed in the act included specific prohibition from mining certain alluvial valley floors, and stringent reclamation standards for those alluvial valley floors that could be mined. The prohibitions to mining are outlined in section 510(b)(5) of the

[19] U. S. House of Representatives, Committee on Interior and Insular Affairs, Report Accompanying H.R. 2, the Surface Mining Control and Reclamation Act of 1977, House Report 95-218, 95th Cong,, 1st sess., 1977, p, 116.

Figure 48.—Stylized Diagram of an Alluvial Valley Floor



SOURCE: Dollhopf, Wendy, Goering, and Hedsberg, "Hydrology of a Watershed With Subirrigated Alluvial Materials in Crop Production," Montana Agricultural Experiment Station Bulletin 715, 1979.

act. This section generally states that no coal mining operation may "interrupt, discontinue, or preclude farming" on alluvial valley floors, unless the lands that would be disturbed are "of such small acreage as to be of negligible impact on the farm's agricultural production. " Alluvial valley floors used as "undeveloped range lands" are not prohibited from mining.

Section 510(b)(5)(B) also states that coal mining must be prohibited if it would "materially damage the quantity or quality of water in surface or underground water systems" that supply those important alluvial valley floors that are prohibited from mining. Thus, mining in areas near important alluvial valley floors would be prohibited if material damage were projected.

For those alluvial valley floors not excluded from mining under the provisions of section 510(b)(5), reclamation standards are established under section 515(b)(10)(F). This section states that a coal mine must "minimize the disturbances to the prevailing hydrologic balance . . . by . . . preserving throughout the mining and reclamation process the essential hydrologic functions of alluvial valley floors. " This requirement to "preserve" both during and after mining "the essential hydrologic functions" is a regulation unique to alluvial valley floors.

Regional Studies of Alluvial Valley Floor Occurrences and Their Relationship to Recoverable Coal Reserves

The first studies of the regional pattern of alluvial valley floor occurrence were conducted prior to passage of the act.[20] The results of these studies are summarized in table 89. Generally, these studies concluded that less than 5 percent of the recoverable coal reserves of the West would be affected by alluvial valley floor provisions. Reexamination of these studies indicates that about 1 percent of the reserves studied in the above investigations would likely be affected by the prohibition provisions of section 510 (b)(5), BLM, in 1980, estimated that almost 60 percent of the available unleased Federal coal in the Gillette, Wyo. area was overlain

[20] Malde and Boyles, 1976; Schmidt, 1977; Hardaway, et al., 1977. See table 89 for full citations.

Table 89.—Alluvial Valley Floor Studies

Study	Study area	Study area underlain by strippable coal or amount of strippable coal considered	Amount or area of strippable coal overlain by AVF
Malde and Boyles, 1976	Southeastern Montana	392,000 acres	10,500 acres
Schmidt, 1977	East-central Montana		
	Burns Creek-Thirteenmile Creek KCLA	2,640 mt	39.2 mt
	Weldon-Timber Creek deposit	657 mt	15.9 mt
	Redwater River	582 mt	46.4 mt
Hardaway, et al., 1977	Existing and proposed mines, Western United States	914,000 acres	27,000 acres

SOURCES **Jack Schmidt. "Alluvial Valley Floors in East-Central Montana and their relatlon to strippable coal reserves, " Denver, Environmental Protection Agency Off Ice of Energy Activities, report No. 8908-4-77-001, 1977.**

H. E, Malde and J. M, Boyles. "Maps of Alluvial floors and strip. pable coal in forty-two 7½ minute quadrangles, Big Horn, Rosebud, and Powder River Counties, Southeast Montana", U.S. Geological Survey Open File 73, Report No. 76-162, 1976,

John E. Hardaway, Dan B. Kimball, Shirley F. Lindsay, Jack Schmidt and Larry Erickson. "Sub-Irrigated Alluvial Valley floors – A reconnaissance of their properties and occurrence on coal resource lands in the Interior Western United States: Louisville, " *Proceedings of Natoinal Coal Association/Bituminous Coal Research Symposium, 1977,* **p. 61-135,**

by potential alluvial valley floors. BLM made no attempt to distinguish between areas likely to be prohibited from mining and areas where special reclamation standards would be required. Examinations of this study by OSM indicate that BLM has also identified areas that will not be classified as alluvial valley floors.[21] Thus, the BLM study almost certainly greatly overestimates alluvial valley floor occurrence.

OSM identified alluvial valley floors in the Alton, Utah coalfield.[22] No attempt was made to distinguish between areas likely to be prohibited from mining and areas where mining would be allowed. Of the 325,000-acre area considered under the Alton unsuitability petition, less than 5 percent of the area was designated as alluvial valley floor of either type.

"Personal communication: OSM Region V, Chief, Branch of Earth Sciences and Geot echnics.

[22]U .S. Office of Surface Mining, Southern Utah Petition *Evaluation* Document, 1980.

Determinations Made by Federal and State Reclamation Agencies in the Powder River Coal Basin

The Montana Department of State Lands, with the concurrence of OSM, has determined that Squirrel Creek valley in Big Horn County is an alluvial valley floor, portions of which are being actively farmed and are significant to agriculture. The stream is a intermittent tributary of the Tongue River and crosses portions of Federal coal leases held by the Rosebud Coal Sales Co. (lease No. M-061686) and the Consolidation Coal Co. (lease No. M-46292). Areas with significant farming activities total about 250 acres; however, the total alluvial valley floor, which contains Federal and non-Federal coal reserves, is more than 1,250 acres. Alluvial valley floors, although not necessarily significant to farming activities, cover about 35 percent of the Consolidation Coal proposed mine plan area and over 40 percent of the Rosebud Coal Sales proposed mine plan area. [23]

At this time, it is not known what effect the alluvial valley floor determination will have on mining in this area. Areas considered significant to farming cannot be mined, even if they are reclaimable. On the one hand, it is possible that no mining of either lease will take place, particularly if the Montana DSL determines that mining of adjacent areas would result in "material damage to the Squirrel Creek Valley. " On the other hand, mining might still be able to take place on the surrounding uplands. Consolidation Coal intends to submit a proposed mine plan for nonalluvial valley floor areas in early 1982. The companies have estimated that a total of 100 million tons of Federal and non-Federal coal under both leases would be affected by the alluvial valley floor decision.[24]

State regulatory authorities, with the concurrence of OSM, have identified alluvial valley floors that are considered not to be

[24]Nimick, personal communication, Montana Department of Stale Lands hydrologist, 1981.

"Ibid.

significant to farming at the Buckskin, Rawhide, Eagle Butte, and Coal Creek mines, all located in the Powder River coal basin of Wyoming (see table 90). The Coal Creek mine, operated by the Thunder Basin Coal Co. (a subsidiary of Atlantic Richfield Co.), obtained approval for its mine in early 1979 and began coal shipments in late 1981. Regulatory authorities designated 846 acres of the total proposed mine plan area, or about 9 percent, as alluvial valley floors. Although initial approval was obtained for the first 5 years of mining, the regulatory agencies have stated that Thunder basin coal must demonstrate compliance with section 515 (b)(l0)(F) of the act before any additional mining will be approved. As discussed earlier, section 515(b)(10)(F) requires an operator to demonstrate that the "essential hydrologic functions" of the designated alluvial valley floors will be protected by minimizing offsite impacts and restoring the alluvial valley floors proposed to be mined.

Although only 9 percent of the total mine plan area has been designated as alluvial valley floors, Thunder Basin Coal would be seriously constrained in mining the Coal Creek if the company could not demonstrate compliance with section 515(b)(60)(F).[25] East Fork Coal Creek crosses the middle of the mine plan area. The company maintains that

[25] Smith personal communication, President, Thunder Basin Coal, 1980.

Table 90.—Alluvial Valley Floor (AVF) Summary Table Developed Coal Reserves in the Powder River Basin

Mine	Federal lease area (acres)	Acres of designated AVF significant to farming	Acres of designated AVF not significant to farming	Acres of stream valley under study as potential AVF	Name of stream
Rosebud	8,226	—[a]	—	386	East Fork Armells Creek
Big Sky (g)[b]	4,307	0[c]	0	0	Emile (Coal bank)
					L & Miller Coulee
		—	—	275	Lee Coulee
Spring Creek	2,347	0	0	0	Spring Creek
		—	—	257	South Fork Spring Creek
West Decker (g)	4,961	0	0	0	Spring & Pearson Creek
East Decker (g)	9,410	—	—	386	Deer Creek
Buckskin	599	—	358	0	Rawhide Creek
		—	—	o	Spring Draw
Rawhide(g)	5,697	0	143	0	Rawhide Creek
		0	52	0	Little Rawhide Creek
Eagle Butte (g)	3,520	0	126	0	Little Rawhide Creek
		—	—	10	Dry Fork Powder River
Wyodak (g)	1,880	—	—	240	Donkey Creek
Caballo	5,360	0	0	0	Tisdale Creek and Gold Mine Draw
Belle Ayr (g)	2,401	0	0	365	Cabal lo Creek
Rojo Caballos	3,959	0	0	0	Clabaugh and Desmet Draw
Cordero (g)	6,560	—	—	640 non-Federal	Belle Fourche River
Coal Creek	5,806	0	116	0	Coal Creek
		0	616	0	E. Fork Coal Creek and Tributary
		0	70	0	Middle Fork Coal Creek
		0	44	0	Dry Creek Tributary
Jacobs Ranch (g)	4,352	—	—	240	Little Thunder Creek Burning Coal Draw
Black Thunder(g) .,	5,884	—	—	545	N. Prong Little Thunder Creek and Little Thunder Creek
David Johnston(g)	9,662	0	0	0	—
Totals:					
Federal lease acres	84,931	0	1,525	2,704	
Federal recoverable reserves (million tons)	5,300	0	97	299	

[a] —: Indicates no determination made.
[b] g: Refers to So-called "grandfathered mines;" that is, those mines which were operating prior to passage Of SMCRA.
[c] o: Indicates determination by regulatory agency that no AVFS are along indicated streams.

SOURCE: Off Ice of Technology Assessment; mine plan review.

prohibition from mining East Fork Coal Creek would render the entire operation uneconomic. The entire mine area contains several hundred million tons of recoverable reserves. Despite the uncertainty of the future regulatory decision, Thunder Basin Coal has proceeded with its development, and anticipates that mining approval will be obtained. Even if approval were not obtained for mining the stream valleys, examination of mine plan maps suggests that the ultimate economic impact of a regulatory prohibition could be less than predicted by the company, Individual pits might be developed on either side of the main stream: however, at least 30 million tons underlying the stream would be lost.

Several regulatory decisions concerning alluvial valley floors are pending, and have affected the orderly development of mine plans. Alluvial valley floor studies are underway, with decisions pending, at 10 mines in the Powder River coal basin. OSM does not anticipate that any of the stream valleys in question will be designated significant to farming, and thus be subject to prohibition from mining.[26] At those mines operating prior to passage of the act, mine planning has proceeded under the assumption that mining of alluvial valley floors will be approved. However, formal regulatory approval has not yet been obtained. Plans for mining and reclamation of valleys were submitted by each mine in January 1981, as part of each mine's permanent regulatory program submittal. As of late March 1981, review was proceeding but no State agency had had sufficient time to approve these plans.

At two mines approved after passage of the act, Spring Creek and Buckskin, uncertainty about alluvial valley floor status and reclaimability has led each operator to avoid proposing the mining of areas of uncertain alluvial valley floor status. Studies are underway in each case that may show that the streams can be reclaimed. However, at least temporarily, 59 million tons at Spring Creek and 36 million tons at Buckskin are not proposed for mining.

[26]Kimball, personal communication, OSM, 1981.

The position that State and Federal regulatory agencies take toward compliance with section 515(b)(10)(F) will have a significant effect on the quantity of coal reserves affected by alluvial valley floor provisions. If industry is able to demonstrate that the essential hydrologic functions can be protected or restored during or after mining, then only those alluvial valley floors with significant agricultural activities on them will be prohibited from mining. In that case, it is likely that only the Consolidation Coal and Rosebud Coal Sales leases referred to above, affecting about 100 million tons of Federal and non-Federal reserves, will ultimately be prohibited from mining,

Table 91 summarizes potential alluvial valley floor occurrences on all undeveloped Federal leaseblocks in the Powder River coal basin. Total estimated area of potential alluvial valley floors is about 2,800 acres, which may include about 219 million tons of Federal recoverable reserves. Thus, about 5 percent of the Federal recoverable reserve base of undeveloped lease blocks in the Powder River basin is overlain by potential alluvial floors. Another 2 percent of Federal recoverable reserves in undeveloped lease blocks in the Powder River basin could be prohibited from mining because of the significant to farming provisions. Although the potential for affecting additional reserves through inability to develop orderly mine plans might increase the affected reserves somewhat, the increase is not expected to be substantial.

The impact of alluvial valley floor designations, and the likelihood of identifying areas significant to farming, is of greater concern to private coal owners in the Powder River basin than to Federal lessees. This situation results from the fact that private coal ownership is often concentrated in major stream valleys where significant farming operations are found. This pattern of ownership exists because the earliest homesteaded lands in the West obtained mineral as well as surface ownership rights upon compliance with the

Table 91.—Alluvial Valley Floor (AVF) Summary Table Undeveloped Coal Leases

Lease block	Lease block area (acres)	Acres of designated AVF significant to farming	Acres of designated AVF not significant to farming	Acres of stream valley under study as potential AVF	Name of stream
C X Ranch (Consolidated Coal)	674	245	300	—[a]	Squirrel Creek
C X Ranch (Rosebud Coal Sales)	524			—	
Pearl	541	—	—	40	Little Youngs Creek
Armstrong	80	0[b]	0	0	None
Bass	20.701	0	0	200	Clear Creek Powder River Deadman Creek several tributaries
Arvada	4,366	0	0	750	Powder River Robinson Draw Wild Horse Creek North Prong Wild Horse Creek
Lake DeSmet	9,417	0	0	10[c]	Boxelder Creek and Tributary
Belco	4,551	0	0	240	Negio and Dry Creek
Wildcat	1,571	—	—	120	Jamison Prong and Soukup Draw
Blue Diamond	40	—	—	0	None
Dry Fork	3,580	—	—	300	Dry Fork Little Powder River Prairie Creek
South Rawhide	4,782	—	—	180	Dry Fork Little Powder River Tributary Little Rawhide Creek
East Gillette	4,343	—	—	160	Donkey Creek
Federal		—	—	120	Dry Fork Little Powder River Tributary
Gulf (3)	756	—	—	—	None
East Wyodak	2,560	—	—	25	Lee Draw
North Rochelle	2,000	—	—	18	School Creek Tributary
Rochelle	8,821	—	—	120	Porcupine Creek and Tributary Holmes Creek West Fork Creek Tributaries
North Antelope	320	—	—	—	None
Antelope	4,817	—	—	480	Antelope Creek Logan Draw Spring Creek
Phillips Creek (1) & (2)	4,079	—	—	60	Phillips Creek Dry Fork Cheyenne River
Totals:					
Federal Lease Acres:	78,523	245	300	2,823	
Federal Recoverable reserves: (million, tons)[d]	4,000	<100[e]	e	219	

a—: Indicates no determination made.
[b]o: Indicates determination by regulatory agency that no AVFs are along indicated streams.
[c]There is an estimated 400 million tons of nonfederal coal under a potential alluvial valley floor associated with this lease block.
[d]Tonnage of coal calculated using average coal seam thickness and the assumption that acre ft of coal = 1,800 metric tons. This calculation tends to overestimate reserves in AVFs due to the assumption that the average coal seam thickness covers the whole area of the AVF.
[e]Refers to reserves for entire AVF No estimate available for percentage of reserves under nonsignificant to farming AVF which will be able to be mined

SOURCE: Office of Technology Assessment.

homestead standards. The earliest settlers were attracted to the valleys with perennial streams. Thus, the land and underlying coal reserves located along those major stream valleys with the longest history of agricultural land use are owned by private entities. Only later did the Federal Government begin the practice of transferring surface ownership without transferring mineral ownership. For example, proposed mines such as Montco's, north of Birney, Mont., and Peter Kiewit Sons' Whitney Benefits Mine, north of Sheridan, Wyo., both on or near the Tongue River, face substantial issues related to farming activities on alluvial valley floors.

Alluvial Valley Floor Occurrence in Other States

Alluvial valley floors occur in each of the other Western coal regions. By definition, alluvial valley floors do not occur in Oklahoma or other areas east of the 100th meridian. In Western coal regions outside the Powder River basin, less work has been done on defining alluvial valley floors; however, based on the work that has been done, alluvial valley floors probably occur infrequently in most areas. While only Alderin Creek at the Glenharold Mine in North Dakota is being reviewed for alluvial valley floor status in the Fort Union region, studies by Schmidt (1977) and Hardaway, et al. (1977) indicate that up to 10 percent of the reserve base of that region might be affected by alluvial valley floor concerns.[27] However, the amount of reserves that will be prohibited from mining will probably be much less because most valleys in mine areas are not being actively farmed.

[27] see table 89 for full citations.

In the Green River-Hams Fork region, alluvial valley floors may occur in southwestern Wyoming and in northwestern Colorado. Three blocks in the Kemmerer Field have potential alluvial valley floors covering less than 200 acres. No alluvial valley floors are expected to be designated in the Rock Springs or Hanna fields. In northwestern Colorado, Empire Energy is proposing mining under the Yampa River, in an alluvial valley floor. The impact of other alluvial valley floor areas on mine production is unevaluated at present.

In the Uinta-Southwestern Utah region, alluvial valley floor determinations may affect mine development in the Alton Field as discussed earlier. Elsewhere, effects are expected to be minimal because underground mining generally is not occurring under stream valleys. Alluvial valley floors are not expected to be a significant issue in the San Juan River region because of the general absence of surface water.

Topsoil, Spoil Handling, and Recontouring

OTA has identified one mine where recoverable coal reserves have been rendered unrecoverable by regulatory decision in this issue area. That mine, in the Green River-Hams Fork region in Wyoming, estimated that it lost 5 million tons* due to a limitation on the area where spoils** could be disposed. Additional reserves may be affected in the Green River-Hams Fork region at mines with characteristics similar to the mine discussed here. Regulations on this issue have also affected the cost of mining. These increased costs are discussed under the economic impacts section of this chapter.

*OTA estimates that 15 million tons may ultimately be removed from mining a t I his mine if the State continues its pattern of interpretation of these regulations.

* *Spoil is overburden material removed by mining operations in the course of exposing coal seams.

The Mining Process

The first step in developing a mine pit is the removal of topsoil. Topsoil is either stored in stockpiles or replaced on regraded spoils elsewhere in the mine. Decisions concerning the depth of topsoil to be salvaged at any location prior to mining are based on a soil survey for the mining area. Agreement between the operator and the regulatory agency is reached on how much of each soil type must be salvaged.

Overburden is the rock strata between the ground surface and the target coal seam and between the target seams. (Rock strata in the latter case may also be called interburden.) Spoil may be removed by dragline, truck and shovel combination, or scraper and dozer combination. Depending on the geology of the coal seams, an open pit, area, or terrace pit mine may be developed (ch. 11). Spoil disposal at each type of mine is slightly different. In open pit mines, spoil is stored outside the pit since the entire pit is needed for mining operations. In area or terrace pit mines spoil is disposed in inactive parts of the pit from which coal has already been removed. Requirements to limit out-of-pit spoil disposal or to selectively bury toxic overburden may necessitate different techniques of overburden removal and spoil disposal.

Statutory Control

SMCRA requires that certain standards be adhered to in the handling of topsoil and spoil. Topsoil must be removed prior to mining operations and either stockpiled or immediately placed on a regraded area (sec. 515(b)(5)). If stockpiled, the topsoil must be vegetated in order to protect it from erosion. All mined and regraded areas must be covered with topsoil or "the best available subsoil which is best able to support vegetation" (sec. 515(b)(6)). Since some spoil material may be high in concentration of elements detrimental to vegetation or livestock or may contribute to ground water pollution, spoil must be placed in such a manner as to reduce these effects (sec. 515(b)(10)(A)(19)). The reclaimed land surface must resemble "the approximate original contour of the land." Special exceptions to this requirement are made for areas of very thick and very thin overburden. In those cases, the operator is required to attain the "lowest practicable grade, " to provide drainage, to cover toxic forming materials, and to ensure land surface stability (sec. 515(b)(3)).

SMCRA regulations for topsoil removal require that an operator remove topsoil or other approved plant-growth medium before beginning mining operations, save it in a manner conducive to protecting the primary root medium from contamination and erosion, and redistribute it in a manner that will enhance its productivity. Regulations governing removal and redistribution are defined in 30 CFR 816.21 to 816.24. Removal requirements define the timing for removal as being after vegetation is removed and prior to surface disturbances caused by drilling, mining, blasting, or other such activities. Regulations define which unconsolidated subsoils should also be removed. Certain overburden materials may be used in lieu of, or as a supplement to, topsoil if those materials are approved by the regulatory authority.

Once topsoil is removed, it is desirable to move it only once, placing it where the soil will be permanently part of a new reclamation landscape. When temporary storage of topsoil is necessary, 30 CFR 816.23 defines the procedures to protect the soil from wind and water erosion, and to maintain its physical and chemical composition. Regulations also establish standards to be achieved in replacing topsoil in regraded areas (30 CFR 816.24(b)). Soil tests performed in accordance with regulatory standards are required to determine whether soil nutrients and amendments are necessary for the replaced soil to support the proposed revegetation.

Requirements for backfilling and grading of areas disturbed by surface coal mining are found at 30 CFR 816.101 to 816.105. The focus of these regulations is to "insure the prompt restoration of the disturbed lands to minimize additional damage to the environment, and to return the land to a productive use" (sec. 515(b)(3)). General backfilling and grading requirements consider:

1. the timing of these activities, subsequent to the removal of coal,
2. the contour of the land which must be restored in the final grading process;
3. the procedures to be used when the final thickness is less than 0.8 of the initial thickness* (thin overburden situations); and
4. the procedures to be used when the final thickness is greater than 1.2 of the initial thickness (thick overburden situations).

*InitiaI thickness is the sum of the overburden and coal thicknesses prior 10 the removal of the coal. Final thickness is the product of the initial overburden thickness, prior to coal removal, times a bulking factor, In order to prevent environmental degradation caused by acid and toxic forming materials, 30 CFR 816.103 requires that "a minimum of four feet of the best available nontoxic and noncombustible material (be placed upon) all exposed coal seams and all acid-forming materials."

Implications of Topsoil, Spoil Handling, and Recontouring Issues for Federal Coal Development

In the Green River-Hams Fork coal region, spoil handling requirements have resulted in the loss of about 5 million tons of recoverable reserves at the Black Butte Mine in Wyoming, following a regulatory decision limiting the area outside the mine pit where spoil can be disposed. Mining methods employed at this mine involve development of several distinct pits, many of which require out-of-pit spoil* disposal areas. OSM, in its technical review of the Black Butte Mine plan, determined that the originally proposed out-of-pit spoil areas conflicted with four regulatory standards: 1) the requirement to minimize the overall disturbed area; 2) the requirement to achieve the approximate original contour of the landscape; 3) the requirement to limit disturbance to wildlife habitat; and 4) the requirement to limit disturbance in stream channels. OSM then limited the out-of-pit spoil disposal area, necessitating mine plan changes that resulted in the loss of recoverable coal[28]

Although no other mine in Wyoming or Colorado in the Green River-Hams Fork region has experienced such a limitation to date, the similarity of the mining method used by Black Butte with that of other mines in the region suggests that some other mines in the region, most of which use out-of-pit spoils disposal methods as part of their mining operations, may experience regulatory decisions similar to Black Butte. Other mines where out-of-pit spoils and approximate original contour considerations may result in loss of recoverable reserves include Rosebud Coal Sales, Seminoe No. 2, Medicine Bow, Colowyo, and the undeveloped South Haystack lease. However, SMCRA allows out-of-pit disposal as part of the special regulations specific to open pit mining in the Kemmerer, Wyo, area (special bituminous coal mine regulations).

Proposed mine methods have been changed because of spoil disposal and spoil handling requirements. These requirements have included limitations on placement of excess spoil (East Decker Mine, Montana), the need to bury spoil high in sodium concentrations (Spring Creek Mine, Montana), and the need to bury spoil high in selected elements (Big Sky Mine, Montana; several mines in the Powder River coal basin, Wyoming). At some of these mines, companies claimed that the regulatory changes in mining method resulted in increased costs which are now being passed to the consumer. These increased costs are examined in the final section of this chapter.

Approximate original contour considerations may have effects in areas of steep topography even where coal seams are flat lying. For example, at the Spring Creek Mine in the Powder River basin, recoverable coal underlies a steeply sloping area of sandstone bluffs. The operator is uncertain whether the approximate original contour can be restored. The effect of this concern is unclear at this time. At the nearby West Decker mine, the Montana State reclamation agency has requested the company to mine into the bluff in order to achieve erosion control at the highwall. Thus, the impact of approximate original contour regulations is still uncertain.

*Out-of-pit spoils are those spoils removed in the course of mining that are not backfilled in the mine pit but rather are left on the natural ground surface.

[28]U.S. Office of Surface Mining, Technical Analysis, Black Butte Coal Co. amendment to spoil handling procedures in Area D, 1979,

Revegetation

Public Law 95-87 establishes a uniform stringent standard for revegetation of mined lands that is particularly challenging in the West. Section 515(b)(19) requires the establishment of a "diverse, effective and permanent vegetative cover of the same seasonal variety that is native to the area of land to be affected and capable of self-regeneration and plant succession at least equal in extent of cover to the natural vegetation of the area. " The standard also makes allowances for use of introduced species where desirable and necessary to achieve the approved post mining land use plan. The use of introduced species in the West generally requires more intensive management to maintain optimum levels of productivity compared to restoration of native vegetation. This is generally not feasible in most areas of the West that will be surface mined because the added costs of intensive management usually do not increase productivity sufficiently to pay off. Consequently, most reclamation in the West involves reestablishment of native ecosystems.

Revegetation of surface mined lands has been the subject of considerable controversy in the West primarily because the arid and semiarid climate makes the establishment and maintenance of vegetation more difficult than in the humid East. A study by the National Academy of Sciences[29] concluded that areas receiving 10 inches or more of annual precipitation can usually be reclaimed* provided that evapotranspiration is not excessive, landscapes are properly shaped, and techniques demonstrated to be successful in rehabilitating disturbed rangelands are used. However, the NAS committee concluded that in drier areas receiving less than 10 inches of precipitation, revegetation will be much more difficult and can probably be accomplished only with major sustained inputs of water, fertilizer and management. The committee used slightly less stringent criteria than in SMCRA for defining successful reclamation, and emphasized that its conclusions were not based on long-term extensive controlled experiments in revegetation.

More recent studies that have evaluated revegetation practices in the West[30] have noted short term success in revegetation, but have concluded that the long term success of revegetation through periods of extended drought have yet to be demonstrated, and that revegetation techniques remain essentially experimental in nature,

There is no dispute about whether vegetation can be established on mine land in the West. This has been accomplished through the use of irrigation and intensive management even in the driest areas such as the San Juan River basin and southern Wyoming, and high levels of productivity have been measured at several reclaimed sites in the Northern Plains that have used fertilization and introduced species. However, disagreement exists as to whether native ecosystems with similar levels of productivity and resilience to the stress of drought can be established. Of particular concern is whether a suitable mix of native species can be established that provides good year-round pasture for livestock in the Northern Plains without requiring continued intensive management and whether desert and foothills-shrub vegetation associations that provide critical winter range for large game in the Rocky Mountain coal areas can be established. Another area of concern is the revegetation of spoils high in sodium concentrations, a problem in the Fort Union and Powder River regions.

[29] National Academy of Sciences, Rehahilitation Potential of Western Coal Lends (Cambridge, Mass.. Ballinger Publishing CO., 1974).

*The NAS Committee used the term "rehabilitation'" rather than "reclamation," but in current usage, the two terms are usually used interchangeably.

[30] F. X. Murray (cd.), Where We Agree: Report of the National Coal Policy Project, V.2 (Boulder, Colo.: Westview Press, 1978) and D. P. Wiener, Reclaiming the West: The Coal Industry and Surface Mined Land (New York: INFORM, Inc., 1980),

Reclamation experts differ in the degree of optimism or pessimism with which they view the likelihood of success in reclaiming native ecosystems in the West, but there is general agreement that it will be a number of years before the question is resolved. It has been 7 years since Montana passed the first reclamation law in the West that had stringent standards for revegetation, and as yet no land reclaimed under that statute has developed a vegetative cover that qualifies for bond release,[31] A recent study by the Committee on Soil as a Resource in Relation to Surface Mining for Coal of the National Academy of Sciences concluded that the 10-year time period specified in SMCRA for bond liability after reclamation is completed may not be long enough to demonstrate success of revegetation in the arid areas of the West.[32]

The issue of revegetation has not had a significant impact on the availability for development of Federal coal under existing leases. The main reason for this is that while regulatory authorities recognize that uncertainties remain concerning the long-term success of current revegetation practices, they do not feel that the probabilility of serious failure is high enough to justify rejecting a permit application on the basis of difficult conditions for revegetation. This judgment is evident in DOI's decision on the petition to designate the Alton area in southern Utah as unsuitable for mining. One of the arguments made in the petition was that conditions in the area were too difficult for successful reclamation because of the nature of the soil and the arid climate. However, DOI concluded that revegetation would be successful.[33]

Unless there are dramatic failures in revegetation involving state-of-the-art reclamation practices in the next 10 years, it is unlikely that difficult conditions for revegetation will prevent any existing Federal coal leases from being developed, However, concern over revegetation has required, and can be expected in the future to require modification of mining plans. For example, OSM has concluded that the Black Butte Mine in southern Wyoming has very difficult conditions for revegetation and has required the use of a sprinkler irrigation system.

[31] Personal communication with Bruce Hayden, Administrator of the Reclamation Division of the Montana Department of State Lands.

[32] National Research Council, *Surface Mining: Soil, Coal and Society* (Washington D.C.: National Academy Press, 1981).

[33] Supra note 22.

Wildlife Concerns

Concern about the protection of wildlife habitat has resulted in minimal prohibition of mining and production of Federal coal, In southern Wyoming, in the Green River-Hams Fork region, protection of raptor habitat along outcrop areas has resulted in some changes to mining plans, including contributing to the loss of 5 million tons at the Black Butte Mine (previously discussed in the Topsoil, Spoil Handling, and Recontouring section). The inability of a North Dakota operation to demonstrate reclamation of wooded draws that are important wildlife habitat has led to delay in approval of a mine plan. Despite conflicts between proposed mines and designated critical winter range for game, leasing has taken place in southern Wyoming. Unless endangered species are found to reside on a proposed mine site, it is unlikely that significant amounts of recoverable reserves will be lost because of concerns about adverse effects on wildlife.

Statutory Control

Jurisdiction under SMCRA for protection of fish and wildlife is based on a provision which states that an operation must:

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> . . . to the extent possible using the best technology currently available, minimize disturbances and adverse impacts of the operation on fish, wildlife, and related environmental values, and achieve enhancement of such resources where practicable (sec.515 (b)(24)).

OSM, in developing its final regulations (30 CFR 816.97), interpreted the term "related environmental values" to mean habitat for fish and wildlife. Operators are required to: 1) design electric powerlines and other transmission facilities so as to minimize the potential for electrocution of raptors; 2) locate and fence roads in order to minimize impacts; 3) exclude wildlife from hazardous waste areas; 4) protect or restore riparian areas; and 5) refrain from using persistent pesticides. Where fish and wildlife habitat is to be a primary or secondary postmining land use, an operator must select plant species on reclaimed areas based on their nutritional value and their value as cover, and must distribute these species to optimize habitat. Where cropland is to be established after mining, such as in North Dakota, fields are to be interspersed with "trees, hedges, or fence rows."

Three important Federal wildlife acts also affect coal mines: the Bald Eagle Protection Act, the Endangered Species Act, and the Migratory Bird Treaty Act. Each of these acts is primarily enforced by the U.S. Fish and Wildlife Service (FWS). The Bald Eagle Protection Act requires, among other things, that bald eagles' and golden eagles' nesting areas not be disturbed. Since many Western coal mines have eagle nests located on them, conflicts with this act have occurred. FWS has permitted the moving of eagle nests in a few selected instances.

The Endangered Species Act requires that a determination be made of the occurrence of endangered species on any proposed mine site. If adverse impacts from mining activities are projected, an operator must mitigate or avoid those impacts. To date, no endangered species, such as the black-footed ferret or the peregrine falcon, have been found to be resident on any proposed mine site. The Migratory Bird Act requires enhancement and prevention of loss of migratory bird habitats. This act, though considered in the mine review process, has not affected mining planning to date. Potential effects include possible requirements to protect wetland habitat used by migratory species in North Dakota.

Implications of Wildlife Concerns for Federal Coal Development

Generally, wildlife concerns have not had a significant effect on the ability to produce coal. However, in selected instances, wildlife concerns are limiting recoverability of reserves and the manner in which coal is mined. Particularly in southern Wyoming, mine plans have had to be adapted for the protection of raptor habitat, especially that related to nesting areas for eagles. In North Dakota, mining is being restricted in wooded draws, a scarce wildlife habitat in the State. In northwestern Colorado, surface mining areas conflict with elk habitat; however, mitigation strategies are being studied so that recoverable coal is not lost.

Green River-Hams Fork Region

Topography in southern Wyoming is more diverse than in the Powder River coal basin or the Fort Union region. Southern Wyoming is characterized by intricate drainage features, expanses of rock outcrop, development of long ridges, and other topographic irregularities that serve as good wildlife habitat. Also, big game migration patterns vary from winter to summer, and certain areas of southern Wyoming serve as critical winter habitat for game. Without such critical winter habitat, game populations would decrease substantially.

Eagles and other raptors favor rock outcrops or dead trees along drainages for nests. Eagle populations, particularly golden eagles, are high in southern Wyoming. Coal mine operators generally begin mine pit excavations at or near the coal outcrop. In many cases, coal outcrops are found in conjunction with linear sandstone outcrops, Were it not for concern about raptor habitat on these outcrops, mining methods would generally use draglines to open the initial cuts near the outcrop. The boxcut spoil would be cast over the adjoining outcrop. Such spoiling would cover the original outcrop and thus would cover or destroy raptor habitat. State and Federal reclamation agencies have prohibited this kind of mining method. For example, at the Black Butte and South Clock mines, requirements to protect outcrop areas have resulted in the opening of cuts further away from the outcrop than originally planned. Relocation of the opening pits has also necessitated some rehandling of spoils.

In the Hanna Field, at the Seminoe No. 1 Mine, concern about raptor habitat may result in decreased reclamation costs to the company. An eagle established a nest in an abandoned highwall prior to the highwall's scheduled slope reduction. As a consequence, the highwall may not have to be reduced.

Although not a significant deterrent to lease development in southern Wyoming to date, wildlife values may conflict with future development of Federal coal. With the exception of the Jim Bridger Mine, which is mostly covered by critical habitat for antelope and mule deer, most mine development in southern Wyoming has not been located in areas designated as critical habitat by the Wyoming Game and Fish Department, However, a number of new proposals for the development of coal mining in southern Wyoming could conflict with the preservation of wildlife values, and the Wyoming Game and Fish Department has expressed its opposition to some of these mines. The Red Rim tract, recently leased, includes over 2,000 acres of critical winter range for antelope in Wyoming. Several other proposed mines, such as Red Desert and Atlantic Rim, have significant areas of critical wildlife range, and a competitive lease application by Idaho Power Co. in southern Carbon County, Wyo., was rejected several years ago because of wildlife considerations.

Critics of the Wyoming Game and Fish Department's opposition to these mine development proposals in southern Wyoming have argued that data are insufficient to determine the critical winter range for large game. OTA was not able to evaluate this criticism on a site-specific basis, but did compare areas identified as critical by the Wyoming Game and Fish Department (1979) with data on wildlife presented in the South-central and Southwest Wyoming Environmental Impact Statements (BLM, 1978). This comparison suggests that the Department is rather conservative in identifying areas of concern for large game. For example, the EIS's identified seven leases (Seminoe No. 1, Black Butte, Hanna South, Cherokee, Long Canyon, Twin Creek, and South Haystack) as being partly or completely covered by antelope, elk or mule deer winter range. However, current areas of critical winter range mapped by the Wyoming Game and Fish Department show winter range only on the Long Canyon lease.

Mining may affect wildlife values other than big game herds. Eight developed leases in the Powder River basin and 5 developed leases in southern Wyoming are completely or partly covered by critical habitat for upland game birds. Several black-footed ferret skulls have been found on or near the South Haystack and Rosebud Mines in southern Wyoming. Rare plant species have been found within or adjacent to lease boundaries at the Lake DeSmet Block (Brownish sedge), North Block (Abies lasiocarpa-pinus contorta community), and the South Haystack lease block (malt sagebrush and stemless wild buckwheat).[34]

North Dakota

To date, mining activities have not been affected by the presence of any of the endangered wildlife species that exist in the State. The destruction of woody plants in draws, a scarce woodland resource found in the lignite region of North Dakota, has become a significant issue at Consolidation

[34]Wyoming Natural Heritage Program, 1980.

Coal's Glenharold Mine. The protection of these areas is mandated by State, rather than Federal, statutes. The woody draws, dominated by green ash, box elder, and American elm, are found throughout the Glenharold site in draws, valleys, and along the north- and east-facing slopes of the project area. The understory, consisting of a mixture of shrub species provide habitat for deer and other wildlife. Consolidation Coal's plans to mine across these draws have resulted in opposition from the State Public Service Commission and have delayed approval of Consolidation Coal's mining permit application. Consolidation Coal must demonstrate the ability to successfully reclaim these draws before it can gain regulatory approval for mining these areas. With the exception of the Glenharold Mine, other coal mining operations in the state either contain no woodland areas or have managed to avoid mining these areas.

Other Regions

In northwestern Colorado, surface mines conflict with elk migration and calving areas. At the Energy Fuels Mine, a calving area is being mined. The company, in conjunction with OSM and the Colorado Division of Wildlife, is experimenting with "habitat manipulation." The company is attempting to recreate offsite the type of calving habitat that is being lost due to mining. To date, wildlife concerns in this area are not expected to affect recoverability of coal because of the extensive mitigation strategies available to operators.

Seven of the eight new leasing tracts of the Wasatch Plateau in Utah have critical winter range for big game, Since the tracts involve underground mining, the potential impacts are substantially less than those associated with surface mining,

Cultural Resources

Throughout the Western United States, archeological and historical sites are frequently encountered. Under current statutes and regulations, a comprehensive survey must be undertaken before disturbance. If a site has significant scientific value, it is studied and the artifacts are generally salvaged, Only at sites with significant architectural or recreational value would a site be preserved and prohibited from mining.

However, according to the OSM staff, cultural resource issues are perceived as a "thorn in the side" by industry. Mine operators are frustrated by the rejection of cultural resource surveys determined incomplete by OSM and the subsequent delays in permitting. OSM staff claim that industry has had difficulty taking the cultural resource issue seriously. Often, companies have contracted with firms or universities whose work has been found inadequate by OSM.[35] Future problems may be alleviated if the OSM promulgates guidelines for adequate surveys.

The San Juan basin area has the greatest potential for future conflicts between cultural resources and mining of Federal coal. The Anasazi cultural features of the region are generally recognized by archeologists to have great significance and value. Architectural sites abound and several areas are protected by the National Park Service, Conflicts are likely in the Star Lake-Bisti region where it is likely that coal reserves are found beneath remnant "outlier" communities to Chaco Canyon. Expansion of the Chaco Canyon National Monument to include some of these communities might also affect coal recovery. No attempt has yet been made to quantify these conflicts.

[35]Shafer, OSM staff archeologist, personal communication, 1980.

Statutory Control

Federal requirements for the protection of archeological and historic resources are derived from SMCRA, OSM's authority to protect these resources comes from other Federal laws directed at protecting archeological and historic resources. These include:

1, The Antiquities Act of 1906 (Public Law 59-209, 34 Stat. 225; 16 U.S.C. 431-433);
2. The Historic Sites Act of 1935 (Public Law 74-292, 49 Stat. 666; 16 U.S.C. 461-467);
3. The Reservoir Salvage Act of 1960 (Public Law 86-523, 74 Stat. 220; 16 U.S.C. 469-469 c);
4. The Historic Preservation Act of 1966 (Public Law 89-665, 80 Stat, 915; 16 U,S,C. 470);
5. The National Environmental Policy Act of 1969 (Public Law 91-190, 31 Stat. 852; 42 U.S.C. 4321-4347);
6. Executive Order 11593 (May 13, 1971, 36 F.R. 8921);
7. Archaeological Conservation Act of 1974 (Public Law 93-291, 88 Stat, 174);
8, The Tax Reform Act of 1976; and
9. Archaeological Resources Protection Act of 1979 (Public Law 96-95, 93 Stat. 721: 16 U.S.C. 470).

The more important laws are briefly discussed below.

Under the Historic Preservation Act of 1966, the historic value of any site in the National Register, or eligible for listing in the National Register, must be taken into consideration when any project utilizing Federal funds or under Federal permit might adversely affect such a site. Detailed surveys of proposed mine sites must be undertaken to ensure that all eligible sites are identified prior to mining.

The National Environmental Policy Act of 1969 declares that it is the policy of the Federal Government to use all practical means, consistent with other essential considerations of national policy, to—among other things—improve and coordinate Federal plans, functions, programs, and resources with the objective of preserving nationally important historic, cultural, and natural aspects of our heritage. It directs that the policies, regulations, and public laws of the United States shall be interpreted and administered, to the fullest extent possible, in accordance with the act. Further, it directs all agencies to use a systematic interdisciplinary approach that will ensure the integrated use of the natural and social sciences and the environmental design arts in planning and decisionmaking which may have an impact on man's environment, It further requires that, on all federally sponsored or licensed projects which significantly affect the environment, the responsible official submit an environmental impact statement that assesses the impact of the proposed action and any unavoidable adverse environmental effects (this has been consistently interpreted to include impacts to archeological and historic resources), sets forth the alternatives to the project, identifies the long- and short-term results, and identifies any irreversible and irretrievable commitment of resources required by the project.

The Archaeological Conservation Act of 1974 specifically provides for the preservation of historical and archeological data (including relics and specimens) that might otherwise be irreparably lost or destroyed as a result of alteration of the terrain caused by any Federal construction project or federally licensed activity or program.

Together, these acts require that OSM ensure that all potential archeological or historic sites are identified and salvaged before mining. Actual preservation of sites will probably only be required where significant structures exist.

Economic Impacts of Environmental Regulations on Federal Coal Production

Environmental regulations may have an economic impact on Federal coal production in two major ways: 1) income foregone by the leaseholder in terms of profits, and by the Federal Government in terms of royalties, as a result of leaving coal in the ground that would otherwise be recovered if environmental concerns were not considered; and 2) increased mining costs because of changes in mining methods necessitated by environmental regulations.

Losses of reserves attributable to environmental regulations can be quantified and OTA's evaluation of existing Federal leases has found that most mines currently producing Federal coal have not had to leave reserves in the ground as a result of environmental requirements. Furthermore, losses of reserves at those mines at which environmental requirements have, or will, prevent mining of reserves usually involve small tonnages in comparison to the total reserves in a mine block. In the Powder River basin, 700 million tons of Federal reserves under lease are likely to be under alluvial valley floors, but only a small portion of these Federal reserves (less than 100 million tons) appear to be subject to clear prohibition against mining. Delays of mine plan development at two mines because of alluvial valley floor issues (Buckskin, Spring Creek) have affected another 95 million tons of the potential 700 million tons. Most reserves under alluvial valley floors can be mined if adequate reclamation can be demonstrated; such demonstrations are expected. Regulatory decisions that have resulted in prohibitions have affected a total of 29 million tons (see table 92), and the recovery of perhaps another 200 million tons of Federal reserves may be delayed or otherwise affected by regulatory decisions. In comparison to total leased Federal reserves (16.5 billion tons), these reserves are small.

Analysis of the impact of environmental regulations on the cost of mining coal is difficult because of both conceptual and practical problems in quantifying the impact of such regulations. A recent study that analyzed the economics of reclamation has identified a number of the difficulties involved in quantifying the cost impacts of environmental regulations as follows:[36]

1. A conceptual problem with cost-benefit analysis of reclamation is that costs are relatively easy to consider in monetary terms (i.e., costs imposed on coal operators and consumers of coal), but costs of not reclaiming mine sites (i. e., the benefits of reclamation) are often difficult, if not impossible, to measure in monetary terms.
2. Reclamation costs are highly site-specific. For example, earth-moving costs associated with reclamation may vary by a factor of 3 or 4, and since these costs may be as much as 90 percent of reclamation costs, such variations significantly affect total cost at a site.
3. Inflation and questions of cost allocation, such as the extent to which earth-moving costs should be considered mining or reclamation costs, make precise measurement of reclamation costs difficult.
4. Coal operators are generally unwilling to disclose the detailed costs of mining and reclamation for business reasons, so most cost data available is based on hypothetical information from engineering studies, or publicly financed experimental projects which often do not create optimum conditions for achieving the least cost in production.

[36] National Research Council, Surface Mining: Soil, Coal and Society (Washington, D. C.: National Academy Press, 1981).

Table 92.—Summary of Impacts to Federal Recoverable Reserves From Environmental and Reclamation Considerations

Issue area	Specific issue	Location of affected area	Federal reserves affected (millions of tons)	Effect
Air resources	Expansion of mine production rate in a nonattainment area	Rosebud Mine, Colstrip, Mont.	1.5 ret/y after 1985 or about 30 mt of reserve	U , effect would be to limit production rate, not prohibit any mining areas
	Permitting of additional powerplants near class I area where SO_2 levels for existing and permitted but not constructed facilities are currently predicted to be at maximum PSD level. The additional powerplants would be fueled by lignite mines in the vicinity.	West-central North Dakota	<100	U , improved air quality modeling techniques being developed
Lands unsuitable for mining	Impacts of coal mining will damage important esthetic values of Bryce Canyon National Park	Alton Coalfield, southern Utah	24	Ap -on portion of proposed mine area designated as unsuitable; rest of leasehold unaffected.
Water resources	Subsidence of mine will divert surface and ground water and adversely affect other uses	Mt. Gunnison Mine, west-central Colorado	23	U, approval likely if mine will buy or replace senior water rights affected.
	Alluvial valley floor (AVF) in areas significant to farming	CX Ranch leases Montana portion of the Powder River basin	<100	Ap uncertain
	Developed mines with stream valleys under study as potential AVF where mine plan development has been delayed	Powder River basin Buckskin and Spring Creek mines	95	D, mining of valleys expected
	Designated AVF in developed mines. Valleys not significant to farming. Mine plan development affected	Powder River basin Eagle Butte, Rawhide, Coal Creek mines	61	U, mining of valley expected
	Potential alluvial valley floors which existed in developed mines prior to passage of SMCRA. Reclamation plans must still be approved	Powder River basin Big Sky, East Decker, Eagle Butte, Wyodak, Belle Ayr, Jacobs Ranch and Black Thunder mines	240	U, mining of valleys expected
	Potential AVFS in undeveloped coal lease areas	Powder River Basin	219	U, mining of most valleys expected
Spoil handling and protection of raptor habitat	Limitation on out-of-pit spoil area	Black Butte Mine Green River-Hams Fork region	5	Ap
	Limitation on out-of-pit spoil area	Green River-Hams Fork region	50	Possible problem; resolution uncertain
	Mining in environmentally sensitive woody draws	Glen Harold Mine, west-central North Dakota	29	D

'Total Federal reserves under lease are 16,500 million tons,
²Ap-absolute prohibition; D-delay in approval; U-unresolved
³Jurisdiction lies with the Montana Department of Health and Environmental Sciences.
'Jurisdiction lies with the North Dakota State Department of Health
⁵Decision made by the Department of the Inter[or, 1960, Decision under appeal to Federal courts.
⁶Jurisdiction lies with Colorado Department of Natural Resources and U S Office of Surface Mining.
'Under sec. 510(b)(5) of SMCRA. Jurisdiction lies with the Montana Department of State Lands. The department has ruled that the alluvial valley floor is significant to farming. The lessee has asked the department to reconsider its decision.
⁸Jurisdiction lies with Montana Department of State Lands (Spring Creek) and Wyoming Department of Environmental Quality (Buckskin)
⁹Jurisdiction lies with Wyoming Department of Environmental Quality
'"Lead decision made by OSM.
"Permit application denied by North Dakota Public Service Commission on grounds that plans for reclamation of wooded draws were Inadequate

Table 93 summarizes "typical" reclamation cost estimates in 1978 dollars in the West, Midwest, and Appalachia, showing costs before and after passage of SMCRA. It is evident that both on a per-ton and a per-acre basis, reclamation costs are significantly less in the West than in the Midwest and Appalachia, The largest part of the cost increases in the West attributable to SMCRA is the 35 cents/ton fee for the abandoned mine reclamation program, which is not strictly an increase in production costs, but rather is a tax to pay for rectifying the environmental costs of past mining practices. When this reclamation fee is subtracted from the estimated total reclamation costs in table 93 to reflect cost increases attributable to changes in mining method, "typical" reclamation costs in the Midwest are 8 times higher than in the West and more than 20 times higher in Appalachia than in the West. The main reason for this large difference in cost is that much thicker coal seams are mined in the West, and the large size of many mining operations allows considerable economy of scale. The main reasons incremental costs in Appalachia and the Midwest are greater with Public Law 95-87 compared to the West is that water pollution control is much more difficult in Appalachia and in the Midwest. Also, prime farmland reconstruction requirements require a larger relative change in materials handling than in the West.

Table 93.—Summary of "Typical Reclamation Cost Estimates (in 1978 dollars)[a]

	$/ton		$/Acre	
	Range	Mid-[b] point	Range	Mid-[b] point
1. Pre-Public Law 95-87 (SMCRA)				
a. Appalachia	$3.23-7.16	$ 5.19	$2,676-14,915	$9,460
b. Midwest (rowcrop)	1.40-2.73	2.07	7,000-10,000	8,500
c. West	0.08-0.39	0.24	1,899- 8,186	5,043
2. Incremental cost with Public Law 95-87 (SMCRA)				
a. Appalachia	—	5.24	—	—
b. Midwest (rowcrop)	–	1.80	—	—
c. West	—	0.57	–	—
3. Estimated total reclamation costs with Public Law 95-87 (1 +2)				
a. Appalachia	—	10.33	–	—
b. Midwest (rowcrop)	—	3.87	–	—
c. West	—	0.81	–	—

[a]This table presents cost estimates developed by the NAS Committee on Soil as a Resource in Relation to Surface Mining for Coal, based on a synthesis of all studies available as of 1980. However, until more experience is gained with the reclamation provisions of Public Law 95-87, cost estimates will remain uncertain. The NAS report notes that these cost estimates are probably higher than costs will be in the long run.

[b]The midpoint values for $/ton and $/acre were derived independently from the two sets of ranges and thus are not directly comparable to each other.

SOURCE: National Research Council, *Surface Mining Soil, Coal and Society* (Washington, D.C National Academy Press, 1981)

On a site-specific basis, Federal coal may experience significant cost increases because of environmental regulations, but such situations appear to be the exception rather than the rule. Two areas where such impacts may be significant on a site-specific basis are the extensive hydrologic data collection and analysis that is required in Public Law 95-87 for permit applications, and requirements necessitating changes in spoil handling procedures. The effects of these extensive hydrologic data collection and analysis requirements are greatest on small operators or companies with limited financial backing. Although OSM's Small Operator Assistance Program offsets costs for the smallest size operations, somewhat larger mines may have difficulty conducting the required studies. However, comparison of the detail of mine plan data submittals to OSM indicates that considerable variation exists in the detail of hydrologic information considered acceptable. Mine operations in the Northern Great Plains are required to submit more comprehensive data than mines in other areas.

There are several examples of the impacts of requirements under SMCRA concerning spoil handling. The Decker Coal Co, has claimed that the change in mining methods necessitated by prohibition of placing spoil in an intermittent stream valley adjacent to their East Decker mining area increased the cost of mining by several dollars per ton. These costs were passed on to the consumer in the form of increased coal prices. At present, the city of Austin, Tex., is suing the Decker Coal Co., challenging the validity of the increased prices. The case has not been resolved. At the Black Butte Mine in southern Wyoming, restrictions on placement of out-of-pit spoils has required significant modifications of the original mining plan, but these modifications apparently have not jeopardized the viability of the mining operation,

In summary, OTA has identified a number of examples on existing Federal coal leases where there are demonstrable economic impacts on mining because of environmental regulations, both in terms of revenues foregone because of the necessity to leave coal in the ground, and through increases in mining costs. However, to date, and in the foreseeable future, total reserves lost through such requirements appear to be relatively small, and OTA has not identified any situations where the overall viability of a mining operation has been jeopardized because of increased costs attributable to environmental requirements. Significant modification of mining plans to accommodate environmental concerns is not uncommon.

The primary reason that environmental regulations appear to have had a relatively small impact on Federal coal production is that costs resulting from these regulations are small when compared to other major coal-producing regions. Current requirements concerning out-of-pit disposal of spoils have the greatest relative impact on mining costs in southern Wyoming, and northwest Colorado, where the mining of dipping multiple coal seams creates difficult conditions for surface mining. Improved spoil handling methods through the reorientation of pits and expanded use of truck-shovel combinations rather than draglines may lead to resolution of many of these problems, but at the present time it appears that SMCRA has reduced the competitive position of coal mined in southern Wyoming compared to coal from the Powder River basin, although this change is difficult to quantify.

CHAPTER 11

Mining Technology

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Contents

List of Figures

CHAPTER 11

Mining Technology

The Federal Coal Leasing Amendments Act of 1976 charged OTA to assess the feasibility of the use of deep-mining technology on leased areas. With the passage of the Surface Mining Control and Reclamation Act of 1977 congressional interest in the study of deep underground mining technology shifted its principal focus from a concern for the protection of surface resources to a concern for maximum economic recovery and the conservation of the resource. Lessees are required to mine all coal that can be extracted economically and within the limits of safety and technology so that coal reserves are not left in the ground where they can deteriorate and not later be retrieved. Underground mining methods usually leave a significant portion of the coal reserve in the ground, Some underground mines recover only **30** to **50** percent of the minable resource, although, averaged over all underground mines in the United States, the recovery ratio is **63** percent. Surface mines, on the other hand, typically recover from **70** to **90** percent of the minable resource.

[1]The recovery ratios used in this chapter are derived from the following sources: 1) R. L. Lowrie, *Recovery Percentage of Bituminous Coal Deposits in the United States*, Bureau of Mines, RI 7109, 1968; E. S. Secor, G. M. Larwood, A. B. Gupta, and A. S. Lees, *Coal Recovery From Bituminous Coal Surface Mines in the Eastern United States: A Survey*, Bureau of Mines, IC 8738, 1977; and R. G. Reese, B. B. Dash, and P. A. Hamilton, *Coal Recovery From Underground Bituminous Coal Mines in the United States by Mining Methods*, IC 8785, 1978; 2) OTA review of lessee mine plans; and 3) personal communication to OTA from Eugene R. Palowitch, Director, Pittsburgh Mining Technology Center, U.S. Department of Energy.

Introduction and Overview

This chapter summarizes OTA'S review of the mining technologies currently in use on Federal leases and the potential for commercial mining technologies to extract Federal coal reserves from deep underground seams. The chapter discusses:

- three surface mining techniques that are used in the West: 1) area strip, 2) open pit, and 3) terrace pit;
- two methods of underground mining in the West: 1) room and pillar with continuous miners, and 2) longwall mining;
- recent underground mining technology developments in Europe and the Western United States that could affect the production of coal from Federal leases; and
- factors affecting the choice of these underground coal mining technologies in the West, including: 1) capital requirements, 2) resource recovery, 3) labor, 4) production and productivity, 5) environmental impacts, and 6) health and safety.

A number of technological innovations have been developed recently for underground coal mining, but the greatest near-term commercial promise for the expansion of underground coal mining in the Western United States appears to be the implementation of longwall mining techniques developed in Europe. Although longwall mining is used virtually exclusively to produce coal from underground mines in Europe, it accounts for only 5 percent of annual underground coal production in the United States. Longwall systems have been used in several European countries to extract most of the reserves in 30-ft thick seams at depths of 3,000 ft. In the United States, on the other hand, such recovery of thick, deep underground seams is still in the development stage,

Some of the largest underground mines in the West, including several that produce Federal coal, have recently converted to longwall mining. Longwall mining is also scheduled to be installed at other large underground operations in the West. For these reasons, much of this chapter compares longwall mining with the dominant underground mining technology in the West—room-and-pillar mining with continuous miners.

Federal coal reserves in the Rocky Mountain province provide the greatest near-term potential for the application of longwall mining. The first successful longwall operation in the West was the York Canyon Mine of Kaiser Steel located near Raton, N. Mex. Although the York Canyon Mine is not located on Federal leases, New Mexico provides opportunities for the implementation of longwall mining on Federal land.

Longwall systems have also been introduced in several mines with Federal leases in the Book Cliffs Field of central Utah. New concepts are now being implemented and tested to extract coal from thick seams and to mine steeply dipping seams at two mines with Federal leases in Colorado—the Coal Basin Complex of Midcontinent Resources and the Snowmass Mine of Snowmass Coal Co. These projects are likely to encourage the use of longwall mining to extract other thick or steeply pitching coal seams in the area.

Longwall systems are also scheduled to be implemented at two mines with Federal reserves in the Hanna basin of southern Wyoming. In 1981 a longwall system will be introduced at Carbon No. 1 Mine. This system will be the highest longwall unit (14 ft) in the West. Much of the area overlying this operation has already been surface mined. In 1984 Energy Development Co. plans to use a longwall unit at the Vanguard No. 2 Mine.

In the Powder River basin of Wyoming and Montana, where coal is mined inexpensively from large surface mines, it may be technically possible to extract thick underground seams. However, the resource information on deep underground coal deposits in this area is inadequate to assess the economic feasibility of this. The comparatively low-Btu value of coal in the Powder River basin and the very large, inexpensively minable surface deposits in the basin are economic barriers to underground mining in this region at least throughout this decade.

A potential method for recovering energy from coal is through in situ gasification of deep coal seams that cannot be mined by surface mining methods. The thick coal seams in the Powder River basin are considered attractive in their potential for in situ gasification, and two separate small-scale test sites have been developed in Campbell County, Wyo., one by the Department of Energy (Hoe Creek Site) and another by ARCO Coal Co. In situ gasification in this country is still in early experimental stages. A major disadvantage with in situ gasification is that it does not produce pipeline quality gas. Thus, unless there are industries nearby that could use low- or medium-Btu gas, a surface facility must be constructed to upgrade the gas to pipeline quality or perhaps to convert it to methanol. The National Coal Policy Project concluded that even if in situ gasification experiments in the Powder River basin are successful, the distance of the region from centers of demand is likely to limit application of the technology.[2] Considering the present state of development of the technology, in situ gasification is not likely to be used commercially in the Powder River basin until the mid-1990's at the earliest.

To date, the experience with longwall mining both in Europe and the Western United States points to significant potential advantages in terms of increased resource recovery, higher production and productivity, reduction in the cost of labor and frequently in the overall costs per ton of coal, the control of differential subsidence on the surface, and a reduction in the number of unintentional roof falls at the face. One should not conclude, however, that longwall mining will realize these advantages in all underground mining environments or that longwall mining can be

[2]F. X. Murray (cd.), Where We Agree: Report of the National Coal Policy Project (Boulder, Colo.: Westview Press, 1978).

used profitably and efficiently in all of the deep Federal coal seams in the West. The decision to implement a particular underground mining technology at a particular site can be made rationally only after the completion of comprehensive sit e-specific geological, engineering, economic, and environmental assessments,

In spite of the positive experience with longwall mining both in Europe and the United States, many underground coal producers in the West will be reluctant to install this mining technology because of its high initial capital cost. The cost of a typical longwall installation is $9 million; total capital cost of the technology per ton of coal mined over the life of a system is about $1,50. This compares to a capital cost of $0.40/ton of coal mined over the life of the system for the typical room-and-pillar operation in the West, using continuous miners. In many cases, the savings in labor and the other advantages of using longwall mining may not be sufficient to offset this cost differential. Nevertheless, longwall systems are likely to figure prominently in mining underground Federal coal reserves in several areas of New Mexico, Utah, Colorado, and Wyoming.

Review of Coal Mining Technologies Currently Used at Federal Mines

Although underground mining was, at one time, the principal mining method in parts of Colorado, Montana, Wyoming, and North Dakota, and continues to be so in Utah, surface coal mining now predominates in most areas of the West. Because coal seams are generally thicker and nearer the surface in most Western States, compared to the East, they are more amenable to recovery by surface mining techniques. Surface mining operations are usually well-suited to the many areas of the West that have not yet experienced the extensive development of towns, cities, highways, and railroads characteristic of the Midwest and the East.

Surface Mining Techniques

Surface mining of coal is characterized by the use of large, capital-intensive and efficient mining equipment. First, the overlying soil and rock layers (overburden) are removed. The coal is then fractured with explosives or machines, and loaded onto vehicles for haulage from the mine site. Finally, the disturbed land must be fully reclaimed. Principal considerations in the selection of surface mining and reclamation techniques and equipment include the thickness and character of the overburden, the dip of the seam, the thickness and number of recoverable seams, and the physical and chemical characteristics of the coal. The three surface mining techniques most widely used in the West are area strip, open pit, and terrace pit.

Area Strip

Area strip is the principal surface mining technique used in the United States. The technique was perfected in the coalfields of Illinois, Indiana, Kentucky, and Ohio. The capacity of a dragline, the machine used to remove the overburden in strip mining, varies in size from 10 to over 200 cubic yards. Many Eastern mines use stripping shovels instead of draglines; and stripping shovels currently are being used successfully at several strip mines in the West such as the Rosebud Mine in the Montana portion of the Powder River basin which produces Federal coal.

Area strip mining proceeds by first making a box cut into the earth to uncover the initial strip of coal that is to be mined. The strip of coal uncovered will vary from 100 to 200 ft in width and from one-quarter to several miles in length. The actual size of the cut will be determined by the thickness of both the overburden and the coal and the designed production rate of the mine. After the coal has been mined from the bottom of the box cut, the overburden covering the next strip of coal is removed and placed in the void left by the mining of the preceding strip of coal. Mining proceeds with succeeding parallel stripping cuts until the property limits of the mining area are reached (see fig, 49).

Even the largest draglines have limits on how much overburden they can remove from a given operating location. A single dragline can generally remove overburden to depths of 100 ft. However, it is possible to extend the stripping limits to as deep as **200** ft by teaming the principal stripping dragline with additional equipment such as another dragline, a stripping shovel, a bucket-wheel excavator, or fleets of trucks and shovels or scrapers. This additional equipment will increase the total overburden removal costs and can be justified only by significant increases in the amount or quality of the additional coal that can be recovered.

Open Pit

The open pit mining technique currently used in the Western United States was initially developed in the metal mining industry. An open pit mine is characterized by a series of benches, the number of which increases as the mine is deepened. Each one of these benches is **40** to **50** ft in height, and excavation can proceed to depths of hundreds or thousands of feet.

The use of an open pit for overburden removal is justified only where there is an exceptionally thick seam or a series of seams that can be mined in sequence, The single seam mines can be found in the brown coalfields of Germany, but only the multiseam mines are found in the Western United States. The best example of the latter type is FMC's Skull Point Mine located on Federal leases in southwestern Wyoming.

Equipment used for overburden removal in an open pit coal mine is currently limited to truck and shovels or scrapers. The truck and shovel or scraper approach typically provides the most flexibility in the development of a bench system and the mining of coal seams. However, lower overburden removal costs might be achieved if rail or conveyor haulage systems, similar to those used in the copper mines of the Southwestern United States, could be implemented in open pit coal mines,

Terrace Pit

The terrace pit system for surface coal mining has come into use only during the last 5 years (see fig. **50).** This method, which essentially combines the area strip and open pit techniques, is used in the thicker coal beds of northeastern Wyoming and southeastern Montana. In these two areas, the removal of overburden thickness in excess of the 100-ft stripping limit of a dragline is justified economically by the mining of exceptionally thick coal seams.

Terrace pit mines have a system of benches similar to those designed for open pit mining. However, the overburden depths that can be removed economically by the terrace pit method are currently limited to between **200** and 300 ft. so that the maximum number of benches will be about seven, Also, unlike the open pit system, the terrace pit system does not remain in the same location but rather moves across the property in a manner similar to area strip mining. The overburden that is removed from one side of the pit is hauled to the other side of the pit and dumped where the coal has already been mined. As a result, the overburden removal operation of the terrace pit moves constantly in a specified direction, usually down dip during the initial years of mining. The removed overburden is replaced behind the mining operation at a distance determined by the number and size of the benches.

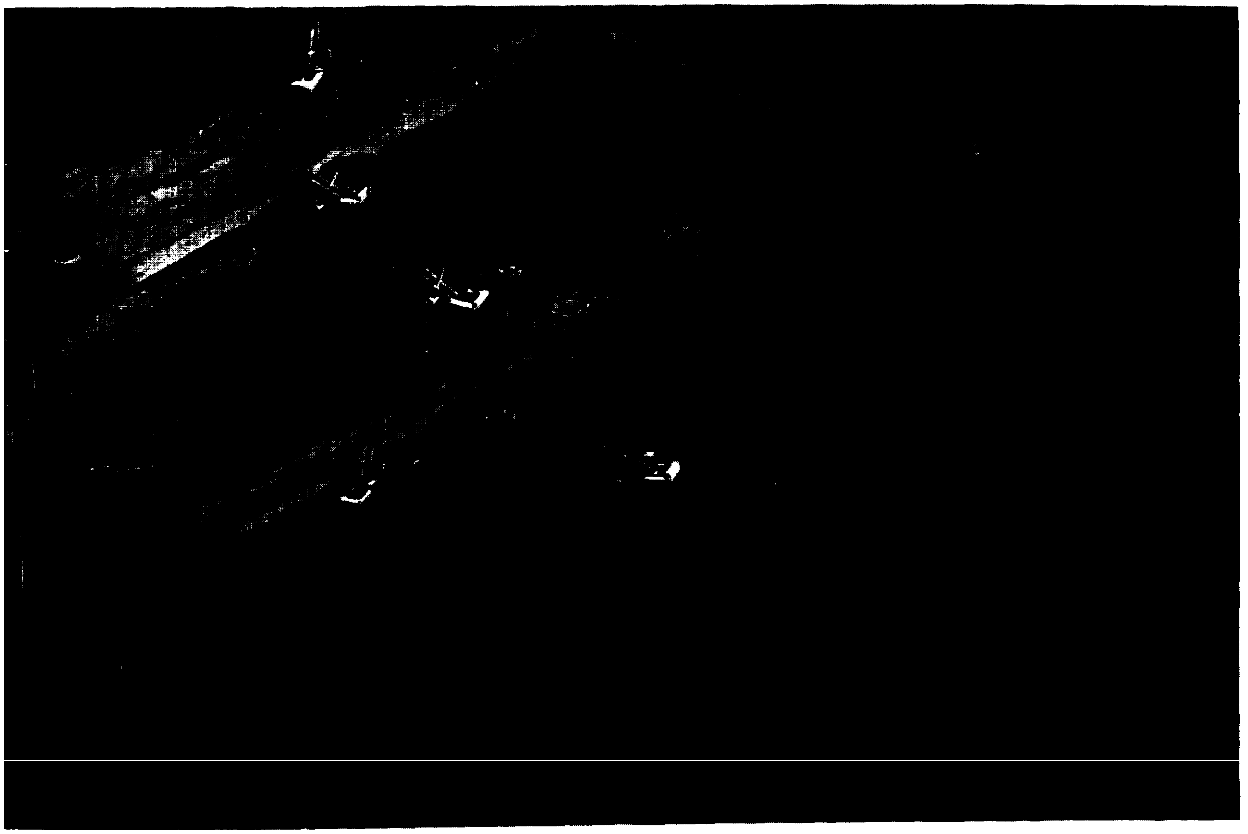
Equipment used for overburden removal and coal extraction in the terrace pit system typically consists of trucks and shovels, although draglines are used at several such mines in the West, including the Rawhide

Figure 49.—Western Strip Mining

Photo credit: Office of Technology Assessmer

Dragline (background) exposes coal seam while front-end loaders (foreground) dump it into trucks for haulage to rail spur or powerplant

Figure 50.—Truck and Shovel Terrace Pit Mine With Two Overburden Benches and Two Coal Seams



SOURCE U S Bureau of Mines

Mine which is located on Federal leases in the Wyoming portion of the Powder River basin. A maximum of two to three shovels will typically be assigned to each overburden bench together with a sufficient number of trucks to haul the material excavated by the shovels to the other side of the pit, The number of shovels used in this operation is determined by the length and the rate of development of the pit. As in open pit mining, other forms of excavation and haulage equipment, such as bucket-wheel excavators and conveyors, are being considered for terrace pit mining. However, the dynamic aspect of terrace pit mining makes it more difficult to use equipment that does not have the mobility characteristic of trucks and shovels,

Underground Mining Techniques

Surface mining is generally preferred by mine operators over underground mining. The reasons for this preference include higher percentage of coal recovery, higher labor productivity, lower operating costs, and fewer safety and health hazards. Also, some environmental impacts of underground mining, such as subsidence, acid mine drainage, and the interruption of aquifers can be greater than those of surface mining, All of these factors are important and will be discussed in more detail later in this chapter. In cases where coal seams are too deeply buried to be recovered economically using surface mining techniques, it is likely that the coal will be mined using one of the two underground mining techniques discussed below, Furthermore, several companies mining Federal coal in the West have had to shift from surface to underground mining as their surface minable reserves became exhausted.

Access to underground mine workings will be by one of three methods. If the coal seam outcrops at the surface it is possible to mine directly into the seam from the surface; this type of mine is referred to as a drift mine. Most underground mines in the West are drift mines. If the minable seam is located under shallow cover then it may be possible to reach the coal bed through the use of an inclined drift (slope); this type of mine is referred to as a slope mine. If neither of these forms of access is possible, then it is necessary to sink a vertical shaft from the surface to the minable seam; this type of mine is referred to as a shaft mine.

The initial capital cost for developing a slope mine may be slightly more than that for developing a shaft mine because, for the same overburden thickness, a slope is approximately three times longer than the depth of a corresponding vertical shaft. However, over the long term, a slope mine has lower operating costs because of the relatively low cost to move men and materials into the mine and coal out. A slope mine is typically more economical when the overburden is less than 500 ft; a shaft mine when it is over 1,000 ft. In the 500- to 1,000ft range a site-specific economic evaluation is usually necessary to determine what type of mine should be developed.

Room and Pillar

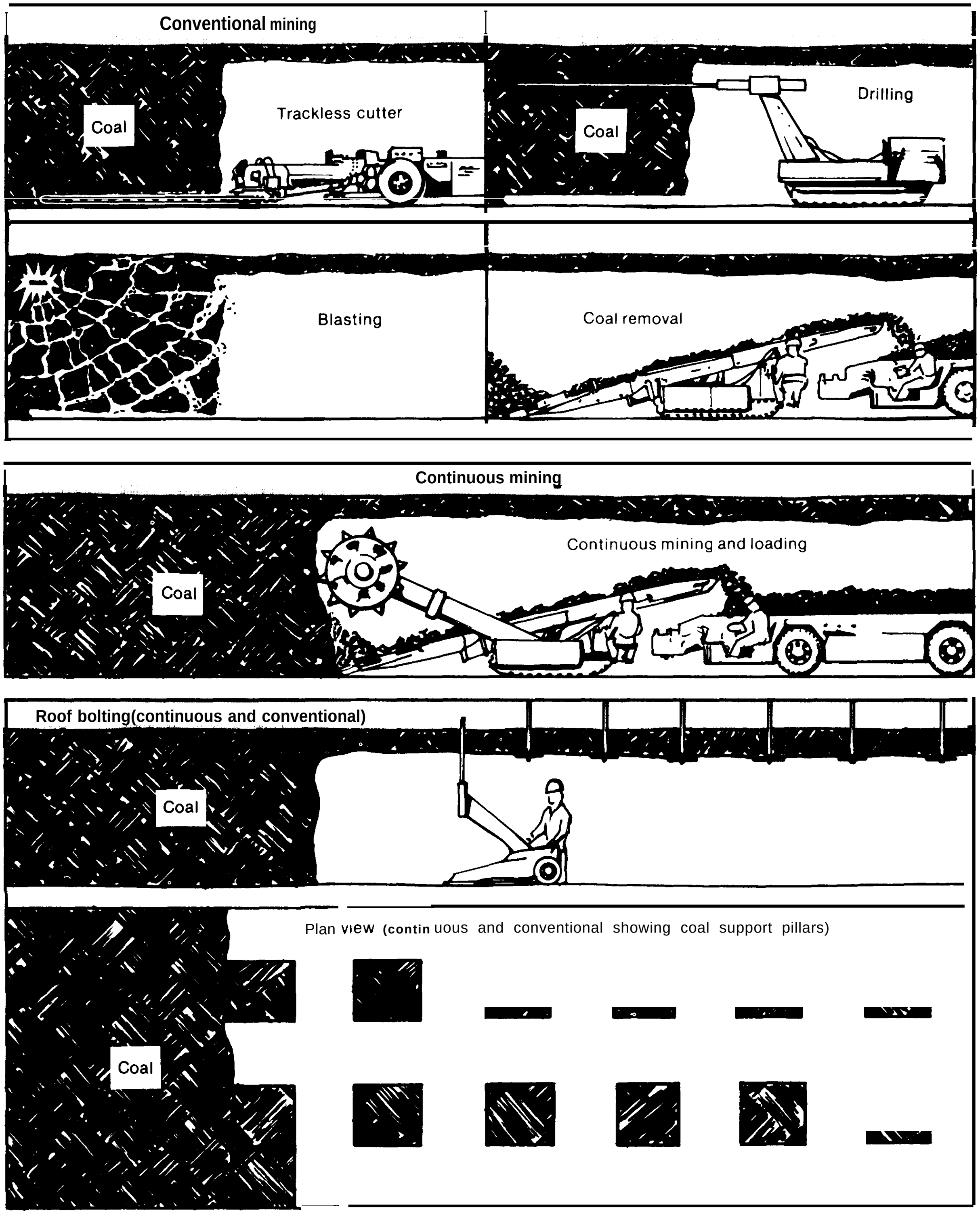
In the room-and-pillar method, the voids left by removed coal form the rooms and the unmined coal forms the pillars (see fig. 51). The pillars are left in place to support the weight of the overlying strata. The principal factors determining the percentage of coal that can be removed from a seam are the thickness of the seam, the strength of the seam and the confining rock strata, the presence of faults or fractures, and the depth of the seam. The deeper the seam, the greater the weight of overlying rock that must be supported; thus the size of the pillars generally will be greater for deeper mines.

The extraction of the coal in a room-and-pillar mine is accomplished using either **conventional mining** or **continuous miners.**

Conventional mining declined in popularity during the 1960’s and most of the 1970’s but continues to account for 35 to 40 percent of the underground coal production in the United States. The first step in conventional mining, which is more labor-intensive than continuous mining, is to cut a slot into the seam with a machine that looks like a large chain saw mounted on a large, rubber-tired vehicle (see fig. 51), Holes are then drilled into the face and loaded with explosives. After blasting, the coal is fragmented and allowed to drop on the floor of the mine. A roof-bolting machine is used to drill vertical holes into the roof and install bolts for roof support. A loading machine is then used to gather up the coal and to load it into rubber-tired shuttle cars which haul the coal from the loader to a conveyor belt for transport out of the mine. In a few instances, a series of bridge conveyors are used in place of the shuttle cars.

Continuous miners are equipped with a rotating head with cutting bits that is used to break coal from the face (see fig. 51). The design of the cutting head and the form of rotation will vary with the manufacturer, but all continuous miners typically break the coal from the face and load it directly into shuttle cars or onto conveyors. As in conventional mining, a roof-bolter is used to install bolts for roof support. The labor requirement for continuous miners is at least 10 percent less than that of conventional mining systems. While continuous miners generally are more efficient, conventional mining can be more readily adapted to certain difficult mining conditions and to large inclusions in the coalbed.

Figure 51.—Room-and-Pillar Underground Mining



SOURCE Office of Technology Assessment

Longwall Mining

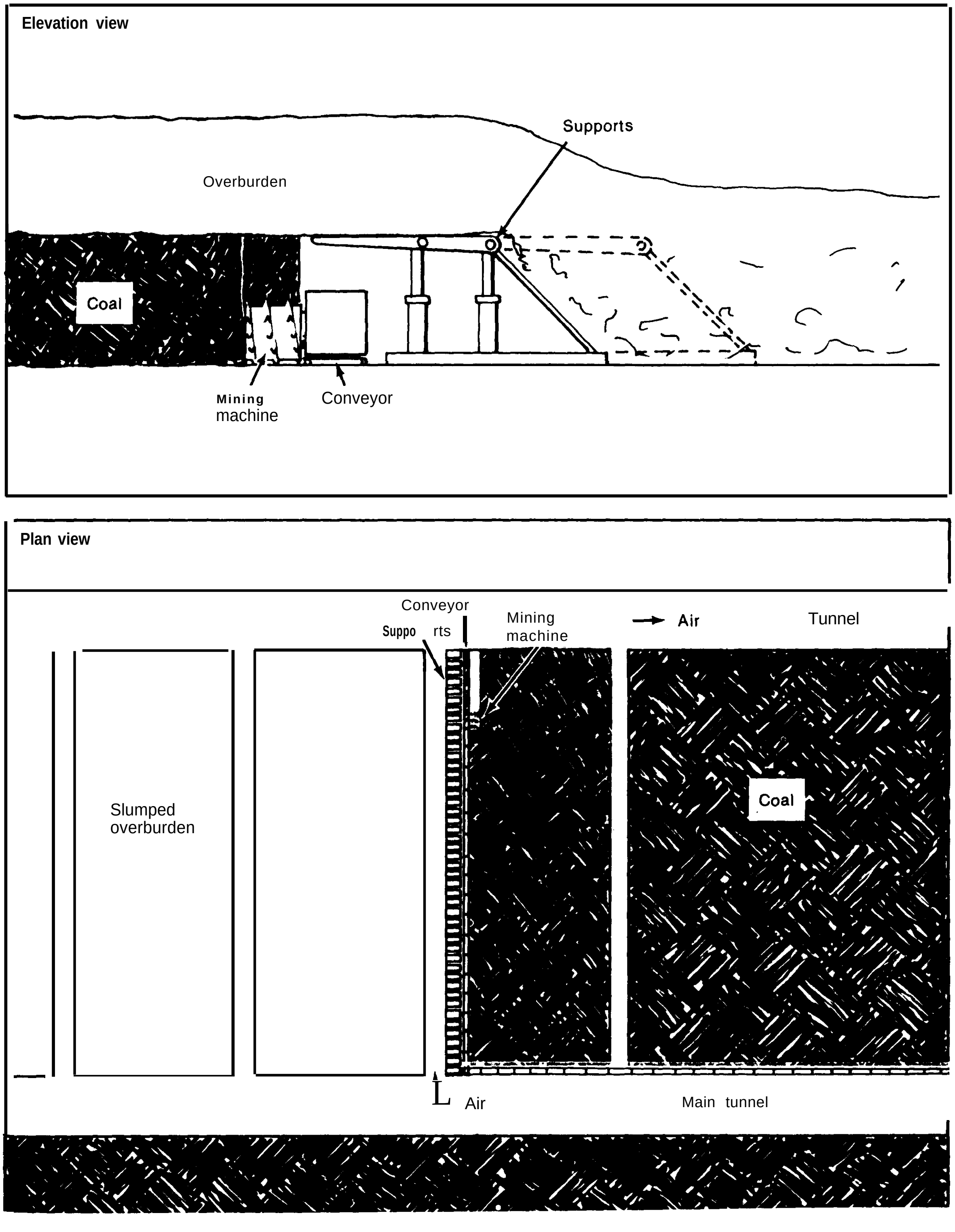
The basic longwall system consists of a set of supports that are located parallel to the mining face, a conveyor system that runs along the base of the face, and a machine that moves back and forth along the face, cutting the coal and loading it onto the face conveyor for transport out of the face area (see fig. **52),** In addition, continuous miners are required for the development of longwall panels. The length of the mining face will depend on a number of factors (discussed in more detail later in the chapter), but will generally range from **400** to **650** ft, with **500** ft being typical.

The basic longwall support system consists of hydraulic rams positioned vertically to support the roof when they are extended. Depending on the size of the mining operation, the rams are arranged into one or more pairs located in the plane perpendicular to the face, When more than one pair of hydraulic rams are used, they will be structurally connected to one or more other pairs to ensure lateral stability. The exact configuration of the rams and the method of interconnecting them will vary according to model or manufacturer. For additional support, a shield support system may be employed. This system uses a protective canopy as a structural part of the support mechanism to protect miners working along the face from roof falls.

The longwall chain conveyor system is mounted on the mine floor in front of the base plate used for the roof support rams or on separate supports, In either case, the conveyor assembly must be flexible to allow for bending as the supports are advanced one after another to keep pace with the advancing face. As the supports are advanced, the roof is allowed to collapse behind them. The typical conveyor mechanism used on a longwall chain conveyor system has a series of horizontal bars or flights that are located perpendicular to the longitudinal axis of the conveyor, These flights are spaced approximately 1 ft apart and are fastened together with chains connected to their ends *or* centers, The chain-connected flights move along the top and bottom surfaces of the chain conveyor system through the force of a gear mechanism which engages the chain. Sideboards are mounted along the top surface of the system so that coal falling into the trough formed by the sideboards will be pulled along by the chain-driven flights.

The machine used to cut the coal from the face and load it on the face conveyor is either a plow or a shearer. Plows are favored in West Germany because of the thin coal seams and soft coal deposits in that country. The cutting action of a plow is just as the name indicates. The height and the depth of the cut will be limited by the amount of pulling force that can be applied to the plow. In the case of shearers, however, the cutting force comes from a rotating drum with cutting bits mounted on it. The diameter of the drum will typically be somewhat greater than one half the face height so that two passes of the drum will be required to mine the full height of the face. The top half of the face is mined first. Since a shearer drum is designed to operate only in one direction, a double-ended shearer makes it possible to cut the upper and lower portions of the face without having to return the shearer to the same end of the face to begin each cut.

Figure 52.—Longwall Mining System



SOURCE Off Ice of Technology Assessment

Analysis of Mining Technology Problems

The preceding descriptions of surface and underground mining techniques currently in use on Federal coal leases are very general. They are intended to introduce the reader to the basic differences between surface and underground coal mining. This section will discuss in more detail the problems that are encountered in using these coal mining technologies. These problems will be illustrated with examples from mines currently operating on Federal coal leases.

Recovery Ratio

Recovery ratio is the percent of minable coal recovered from the seam. Generally, the recovery ratio for surface mining will be higher than that for underground mining because some coal must be left in place in underground mines to support the roof and limit surface subsidence. According to the Bureau of Mines, the average recovery ratio from all surface mines in the United States is 83 percent; for underground mining the national average is 63 percent.

Thick single-seam surface mines often have recovery ratios in excess of 90 percent. For example, the thick-seam mines of the Powder River basin of Wyoming are achieving recovery ratios of 95 percent. The reason for this is that the coal lost at the seam boundaries in a thick seam is a small fraction of the total coal being mined. The operator often does not recover 6 to 12 inches of coal at the upper and lower seam boundaries, because this coal usually contains significantly more mineral matter than the remainder of the seam, The proportionate amount of the seam thickness lost is much less for a 50- or 100-ft thick seam than it is for a 5- or 10-ft thick seam.

A multiseam surface operation will often have a lower recovery ratio than a single-seam mine because a certain thickness of coal is lost for each boundary between a coal seam and the surrounding material. Hence, even though the cumulative thickness of the seams in a multiseam mine approaches or exceeds the seam thickness in many single-seam mines, the percentage of coal **not** recovered will be greater.

Recovery ratios in surface coal mines also can be adversely affected by such factors as extreme seam dip, faults, and characteristics of the overburden material that interfere with stripping operations. Such problems are common in the surface mines of northwestern Colorado and southwestern Wyoming. However, mines such as the Colowyo and the Trapper mines encounter a combination of these problems but still achieve recovery ratios in excess of 80 percent. Seam dip at the Canadian Strip Mine in north-central Colorado is so steep that it has been necessary to implement what is essentially a contour strip operation. Here a bench is cut into the hillside and all of the coal in the bench area is mined. Even though the ratio of waste material removed to coal mined is on the order of 15 or 20 to 1, only a small percentage of the coal is not recovered.

The recovery ratio for underground mining will usually be less than for surface mining as a certain amount of the coal must be left in place around access facilities such as shafts, slopes, drifts, main entries, and submain entries. Additional coal is also lost that is left in boundary pillars around the perimeter of the property and in pillars in the mined out areas to support the roof and prevent or lessen subsidence of the surface.

Recovery ratios for room-and-pillar mines will vary from a low of 20 percent to a high of 80 depending on the completeness of the secondary recovery of pillars from the mining panels. The average recovery ratio for all room-and-pillar mines in the country is 62 percent. Several equally important factors determine the recovery ratio of these mines including the dip of the seam, the presence of igneous or other intrusions in the seam, faults (vertical displacements in the seam), and the depth of the seam. The depth of the seam is important in the West where many mines are

2,000 to **3,000 ft** deep. The greater the depth of the seam, the more overlying rock strata that must be supported by pillars left around access facilities and in the mining areas. To avoid failure of these support pillars due to excessive loading, they must have larger cross-sectional areas, If the pillars are larger, then the amount of coal that can be recovered will be correspondingly less. Support problems caused by the depth of the seam can be aggravated by the presence of faults, poor competency of the rock strata forming the floor and roof of the mine, and excessive water. Several of these conditions are found at mines with Federal coal leases in western Colorado. Conditions became so severe at U.S. Steel's Somerset Mine that one of the mining levels had to be abandoned, Stresses induced in support pillars at this mine caused the pillars to fail explosively, However, according to a spokesman for the Bureau of Mines, this problem has been brought under control at Midcontinent's Coal Basin complex in Colorado,

Recovery ratios for longwall mining range from a low of 50 percent to a high of 80. The average recovery ratio for all longwall mines in the country is 75 percent. * Longwall mining generally results in higher recovery ratios than those achieved in room-and-pillar mining when the latter does not include full extraction of the pillars. A good example of the recovery ratio increases which can be expected from longwall mining when compared to room-and-pillar mining is found in the Deer Creek-Wilberg mine complex of Utah Power & Light in central Utah. These mines had operated as room-and-pillar mines with recovery ratios of 55 to 60 percent. The company has already installed one longwall system and plans to install a second. The recovery ratio for the longwall system at this mine is approximately 80 percent.

Production and Productivity

Although there is no hard and fast relationship between the production rate for a mine and its rate of labor productivity, it is often true that those mines with high production rates also will have relatively high rates of labor productivity, The reason for this is that both surface and underground mines with high production rates generally have training programs and equipment that will generate higher labor productivity y.

The large surface mines of the Western United States have long been characterized by high rates of labor productivity. The productivity of some of these mines is as high as **30** to 35 tons per worker per day. The average productivity rate for all surface coal mines in the United States is approximately 15 tons per worker per day, Since labor is one of the major costs for any mining operation, productivities on the order of 30 or more tons per worker per day translate into significantly reduced unit operating costs. However, high rates of productivity are typically achieved as the result of greater investments in equipment, so that the reduction in unit operating costs will be partially offset by increases in the unit capital costs. Furthermore, capital costs for initial infrastructure development and interest charges are the most significant costs in coal mining.

Because there are fewer operating constraints, surface mining will generally present fewer problems with respect to achieving high production rates and concomitantly high labor productivity rates. The achievement of these goals in underground coal mining, however, requires good mining conditions as well as good management and a willingness to invest in the appropriate equipment. A good example of the high level of productivity that can be achieved in underground mining is the Soldier Canyon Mine of California

[1]Personal communication to OTA from John M. Karhnak, Manager of Ground Control, Division of Minerals. Health & Safety Technology, U.S. Bureau of Mines, Mar. 31, 1981.

*The average recovery ratio for shortwall mining in the United Stales is even higher (84 percent). As in longwall mining, short wa U mining uses chocks for roof support. However, continuous m iners are used in shortwall operations to mine the coal and haulage is done bv shuttle car rather than with a continuous conveyor. Shortwall mining may he used in the future in the West in cases where a 600-ft face is not available. Personal communication to OTA from Daniel J. Snyder, 111, President. Colorado-Westmoreland, Inc., June 15. 1981.

Portland Cement Co. in central Utah. Using a longwall system, this mine is achieving a labor productivity of 23.5 tons per worker per day and an annual production rate of over 1 million tons. This productivity rate is not only much higher than the national average of 8.6 tons per worker per day for underground coal mining but also exceeds that achieved by most surface coal mines,

It is generally accepted that longwall mining represents a better opportunity for achieving higher production rates, higher labor productivity rates, and better safety in underground mining. A room-and-pillar operation using continuous miners can readily achieve shift production rates of 350 to 400 tons. Rates in excess of 700 tons per shift are exceptional, In the case of longwall mining, shift production rates in excess of 1,000 tons are common in the West and rates of 1,500 to 2,000 tons per shift have been achieved at a number of longwall operations.

Environmental

Environmental problems resulting from coal mining operations in the arid West are more likely to be associated with surface mining than underground mining. Environmental issues are discussed in detail in chapter 10. Although the siting of surface facilities for underground mining operations will generally have limited environmental impacts, a potentially greater problem associated with increased underground mining on Federal coal leases is surface subsidence. * The impact from subsidence depends on the location of the mine and is greatest in highly built-up urban areas. This problem is most often associated with cities and towns in the Eastern United States but has also occurred in Western towns such as Rock Springs, Wyo., where buildings and other facilities located in several areas of the city have been endangered.

*Acid mine drainage, which can be an acute problem in many mining areas in the East, is not a significant problem in most arid regions of the West.

Surface subsidence can also be a problem in rural and unpopulated areas. Differential subsidence can break through to the surface in the form of fractures and sinkholes. More typically, subsidence will manifest itself in the form of a generally lowered surface elevation, This will not be a problem unless it occurs under a stream, railroad, highway, building, or dam. Even then, the adverse effects of subsidence can be minimized if the mine is properly planned. In several European countries, especially West Germany, where the art of deploying planned subsidence is well developed, entire towns have been lowered as a result of underground mining without adverse effects.

It is becoming apparent that longwall mining is usually preferred to room-and-pillar mining where surface subsidence may be a problem. The reason for this is that longwall mining is more likely to produce more uniform and predictable subsidence. Concern about the potential impact of surface subsidence on springs and ground water hydrology has been expressed by local residents in mining areas in Utah and Colorado. Subsidence tends to be differential in room-and-pillar mining and may not occur until years after mining operations have been completed. It may then occur without warning and with potentially catastrophic results. However, full recovery of the pillars will usually result in the more uniform subsidence comparable to that achieved with longwall mining.

Roof Support

Deeper mines require that larger support structures be left in place in the underground workings. Greater support can be accomplished by leaving the coal in place or by replacing it with substitute support structures, For longwall mining there is increasing evidence that controlled subsidence of the mined areas reduces support stresses on boundary pillars that are left in place along main and submain entries. In some longwall mines it has been necessary to install supplementary supports such as packs or cribbing, but the amount of support provided has been much less than that required to support the full weight of the overlying rock strata.

Review of Technology Developments in Europe and the Western United States

This section reviews mining technology developments in Europe and the United States and discusses possible solutions of the mining technology problems described in the preceding section.

Because surface mining techniques and equipment in the United States are relatively advanced compared to underground coal mining technology in the United States, only new underground technology developments will be discussed in this section. As the number of underground mining operations increases in the West, improvements in underground mining technology can lead to significant improvements in coal production, recovery ratios, productivity rates, and safety.

Comparison of Mining Conditions in Europe and the Western United States

Mining conditions on Federal coal leases vary from nearly ideal to some of the most difficult conditions anywhere in the world. For example, in certain locations in northwestern Colorado and in northwestern New Mexico the minable seams are a few hundred feet deep and from 6 to 30 ft thick, the dips of the seams range from the horizontal to a few degrees, there are few faults, and the floor and roof rocks are nearly ideal for support. In contrast, the conditions found at some existing mines with Federal leases in western Colorado and central Utah include depths of cover that are over 3,000 ft, seams that range from 4 to over 40 ft in thickness, seam dips that approach 350, extreme fracturing and faulting of both the coal seams and the confining rock strata, and floor and roof rocks of very poor competency. Many mines in Colorado and Utah extract coal from seams that are over 1,000 ft deep.

Mining conditions vary in other areas where there are substantial Federal leaseholdings. For example, in the Powder River basin of northeastern Wyoming the depth of coal seams ranges from **a** few hundred feet to an undesirable 2,000 to 3,000 ft. However, most other mining conditions are good in this area. Difficult mining conditions in the Star Lake-Bisti area of New Mexico include seam dips up to zoo and faults. In Oklahoma, high concentrations of methane gas and undulating, thin seams cause extremely difficult mining conditions on most Federal leases.

Direct comparisons of coal mining in European countries with coal mining in the Western United States can be misleading because many mining conditions are different in these two areas. The principal coal mining countries of Europe—France, Great Britian, Czechoslovakia, the Soviet Union, Poland, and West Germany—are currently mining coal from seams that would be considered unminable in the United States. A condition which is present in all of these countries, but which has not been observed in the Western United States, is extreme folding of the coal seams. In the case of folding, it is necessary to deal not only with steeply dipping seams but vertically oriented seams as well. Most of the coal mined in England is extracted from seams that are deeply buried, thin, folded, and faulted. Both France and Poland are currently operating deep mines with almost full extraction of coal seams 20 to 30 ft thick. However, even though many mining conditions in Europe differ from those in the Western United States, the use of longwall mining in Europe to extract deep, thick seams is relevant to assessing the technical potential for extracting deep, thick seams in the Western United States.

New Equipment Developments

The equipment developments discussed below include both refinements to existing underground mining technology and new equipment concepts that are still in the prototype and testing stage. New equipment and concepts could solve many of the problems described in the section on mining technology problems.

Longwall Mining Improvements

Modern longwall mining technology emerged in its present form in Germany, the Soviet Union, and Great Britain during the latter part of the 1950's after more than 20 years of continuous development in these countries. Refinement and improvement of longwall equipment and techniques have since continued in these countries. The United States has been a late entrant into the use of longwall mining, and the equipment manufacturers in this country have made relatively few contributions to the technology during the past 10 years.

Many of the recent developments in longwall technology have dealt with improvements in reliability and production capability, although there also has been considerable effort to improve safety conditions associated with longwall mining. The discussion of these improvements of longwall mining technology will be organized according to the three principal components of a longwall system; roof support, the face conveyor, and coal cutting and loading.

Principal improvements in the longwall support system have included increases in the load-carrying capability of the hydraulic rams, increased maneuverability of the supports, better stability, and refinements in the controls. Most manufacturers of longwall supports now offer units that have maximum yield loads of 1,000 tons or more, The increases in the maximum yield loads also have been accompanied by the development of shields and chock-shields that offer greater stability and more protection to the miner. Advancement and alinement of the supports now can be done remotely which not only reduces the time required for advancing the support system, but also allows locating miners away from the moving support and out of the way of falling material caused by movement of the support.

The transport of the cut coal away from the longwall face by the face conveyor still remains a major potential bottleneck in the longwall mining system. A breakdown in the conveyor can result from broken flight chains; minor delays also are caused by oversized lumps of coal becoming stuck in conveyor transfer points. The broken flight chain problem has been partially solved by the use of a "twin-inboard" chain at the center of the flight which reduces stress on the flight chains as the flight conveyor bends around curves. The need for a transfer point at the headgate where the face conveyor meets the panel belt conveyor in the headgate entry has been eliminated by the recent innovation of the roller curve in West Germany. The roller curve allows the face conveyor to turn the 900 corner at the headgate and to dump coal directly onto the panel gate conveyor or into a feeder-breaker which reduces the size of oversize lumps and then feeds the coal onto the panel belt conveyor.

The majority of the longwall cutter-loaders installed in the United States are shearers rather than plows. Two major hazards associated with the use of shearers have been high coal dust concentrations created by the cutting action of the rotating shearer drums and the danger from a break in the chain that is used to pull the shearer back and forth along the face. Significant reduction of dust concentrations has been reported through the use of a "Shearer-Clearer" water spray system which was developed by Foster-Miller Associates in conjunction with the U.S. Bureau of Mines. This system partitions the airflow around the shearer into a clean split through the use of water sprays. The coal dust cloud is confined to the vicinity of the coal face while the shearer operators remain in the clean split on the support side of the cutting machine.

The broken chain hazard has been solved by equipment manufacturers in Great Britain, West Germany, and the United States which now offer chainless drives, These drive systems are all based on a variation of the rack and pinion gear system. Initial indications are that these chainless systems already have gained wide acceptance by the operators.

One additional development in longwall technology is a system designed specifically for steeply dipping seams. The system is called the "Troika" and is offered by Hemscheidt America Corp. It is designed for use in seams that dip up to 750 and is scheduled to be used to extract Federal coal from a seam pitching 330 at the Snowmass Mine in Colorado. It consists of three shields connected to a central structural beam by a double-acting ram assembly. The beam is connected mechanically to the center shield and to the outer shields by the rams. The center shield, which has no double-acting ram, is moved by the outer shields with the rams through the beam. The outer shields follow this beam during movement.

The new equipment developments for longwall mining are potentially important, but better use of available equipment is an equally important aspect of technology development for this system. An example of the latter is the use of available longwall technology to extract the maximum thickness possible from seams that are thicker than the approximately 12-ft seams currently being mined with conventional longwall systems.

One approach to thick seam extraction in underground mining is the double lift longwall method currently being developed to mine Federal reserves at the Coal Basin Complex of Midcontinent Resources under a cost-sharing contract with the Department of Energy. With this system, the coal seam is extracted by taking two successive passes of the longwall. Total thickness of the coal seam is 25 ft; by taking two 10- to 12-ft lifts, all but 5 ft of the seam will be recovered. Although this is less than the total seam thickness at Coal Basin, it is a significant improvement over the extraction of 8 to 10 ft of coal achieved with the single lift approach. Conceptually, this method could be extended to extract the full coal seam, using three or more lifts.

Another approach to thick-seam mining using a longwall system, developed in France, uses a single-lift longwall operation under the bottom of the sea. The roof supports on this system have been modified to allow the portions of the seam located above the longwall to cave in behind the supports under the overlying broken roof rock. The broken coal is then collected on a conveyor belt running behind the supports.

Room-and= Pillar Mining Improvements

For some time there has been an awareness that the cutting action used by existing continuous miners is less efficient and produces more dust than alternative cutting actions. Tests of the linear-cutting miner experimental concept developed by the U.S. Bureau of Mines have indicated that deeper cuts at constant depth in the coal face can be made more efficiently, while reducing the respirable dust that is normally generated by continuous miners. It is estimated that this new cutting concept would produce three times the amount of coal with one-third of the dust and would use one-third to two-thirds less electrical power, depending on the cutting depth. However, the development of the commercial machine is not likely for another 20 years.

A concept for extracting more coal from pillars during secondary recovery operations is the underground auger miner developed by FMC under contract to the U.S. Department of Energy. In addition to the recovery of coal in pillars, the system shows a potential for mining out prepared panels of coal at significantly lower cost than conventional methods.

The system consists of an underground augering machine, a two-stage coal conveyor, and auxiliary ventilation and rock-dusting equipment. The auger miner excavates coal by drilling a series of large holes side by side into [he coal seam. The conveyor carries the coal to the mine's face haulage system, The in-hole ventilation and rock-dusting equipment is used to dilute methane gas and coal dust to nonexplosive concentrations,

The availability of efficient and reliable haulage systems has long been one of the goals of underground mining technology development. Existing rubber-belt conveyor systems have gone a long way to satisfy this requirement, but major deficiencies remain at the face. The principal need is for a continuous haulage system which is sufficiently flexible to adapt to the multitude of configurations experienced during the development and product ion from a coal panel. Besides the need for flexible components, there is also a need for an efficient method for transferring coal from one component to another, e.g., from shuttle cars to panel belt conveyors. *

* This need is also eveident for panel development in longwall mining

Long-Airdox has introduced a continuous haulage concept that is based on the use of mobile bridge carriers and piggyback bridge conveyors. A piggyback bridge is atttached directly to the boom of the continuous miner at one end and is supported by a dolly at the other end. This dolly is designed to move freely along rails mounted on top of the sides of a separate mobile bridge. Coal flows from the miner to a piggyback bridge to a mobile bridge to a piggyback bridge, and so on, until it reaches the last piggyback bridge's dolly and is dumped onto the panel belt. Four standard mobile conveyors (each 30 ft) coupled with five standard piggyback conveyors (each 3 to 41 ft) can provide an effective reach of over 300 ft in a seven-entry mining projection.

Other concepts of continuous haulage that have been tested include the use of air and water as the carrying media for crushed coal in pipelines. Although this approach offers some advantages, it is still more difficult to implement than are concepts based on the use of conveyor belts. A slurry pipeline system has been installed in one Eastern mine, however,

Considerations for Using Improved Longwall Mining Techniques on Federal Coal Leases

The preceding sections of this chapter have provided an overview of mining systems currently in use on Federal coal leases and have considered several of the technology problems associated with the use of these systems. This section will address: 1) the cost in capital and labor and the time needed to implement longwall mining and 2) the comparative production advantages and some of the physical, environmental, and social consequences of using this technology.

Capital

During the 20-year period that reliable longwall mining systems have been on the market, an important reason for the reluctance of coal producers to use this technology has been the initial cost of installation. The installation of a complete longwall mining system, not including the cost of development workings and other mine infrastructure, requires the expenditure of a single large lump sum of capital, usually $1.5 million per 100 ft of face length. This cost includes: 1) the face support subsystem, 2) the face conveyor subsystem, and 3) the coal cutting-loading subsystem. The total installed cost of the three longwall subsystems will vary significantly from mine to mine. The more important variables which determine the cost of a specific longwall system include the length of the face, the height of the coal to be cut, the geological conditions of the seam, the thickness and quality of the roof rocks (which determine the capacity of the face support subsystem required), and the rated capacity of the system.

The typical longwall system now being installed in the Western United States has a designed face length of 600 ft and a rated production capacity of 1,250 tons of coal per shift. However, the actual production capacity obtained varies from 700 to 1,500 tons per shift because of variations in mining conditions and in the ability of producers to operate longwall systems. This compares with a national average of 400 tons per shift for longwall systems in 1980.

The cost of this typical longwall installation in 1980 dollars is estimated at approximately $9 million. Assuming that the mine operates 250 days per year and two shifts per day, the rated annual production capacity of the typical longwall system will be 625,000 tons. * If the longwall system is assumed to have a productive life of 10 years, which is not unrealistic if the system is adequately maintained and there is selective replacement of the more expendable system components, then the total production capacity over the 10-year life will be 6,250,000 tons of coal. Hence, the total installed capital cost of the longwall system over the life of the system will be approximately $1.50/ton of coal mined.

The significance of capital cost for longwall mining can be illustrated by the following example. Utah Power & Light installed a longwall system in its Deer Creek mine near Huntington, Utah, in April 1979. The system was designed for a 480-ft face and a 10-ft thick seam. The initial production capacity of the system was 1,500 tons per shift. However, after only 3 months of operation longwall production reached an average of 2,500 tons per shift, Using a schedule of two shifts per day, the initial 3,000-ft long panel was mined out in a period of 6 months for an average production of 2,200 tons per shift.

The impact of the success of this initial longwall system on the entire Deer Creek operation is dramatic. Prior to the installation of the longwall unit, daily production capacity at the mine was 7,000 tons. To achieve this production rate it was necessary to use as many as 10 continuous miner sections. With the implementation of the longwall system the daily production has increased to in excess of 10,000 tons and the monthly production to 220,000 tons. Of this 220,000 tons, a total of 115,000 tons is produced by the single longwall unit and the balance by eight continuous miner sections. With the installation of a second longwall, the company expects the requirement for continuous miners to drop to four sections. Two of these sections will be used for longwall panel development and two to extract pillars from sections of the mine which have already been mined using the room-and-pillar technique.

Prior to the installation of the first longwall unit the Deer Creek Mine was producing 1.75 million tons of coal per year, This rate was achieved through the use of 10 continuous miner sections. Assuming an average investment of $700,000 per section, the total investment in mining equipment was $7 million. Based on a 10-year life for the continuous miners and auxillary equipment, the total capital cost per ton of coal mined over the 10-year period was $0.40. Assuming an installed cost of $9 million per longwall unit, a similar calculation for the 2-longwall and 4-continuous miner production system now producing 2.64 million tons of coal per year results in a capital investment of $0.80/ton of coal produced over a lo-year period, assuming the longwall units and the continuous miners have productive lives of 10 years. Considering the cost of money at 20 percent and total financing of the equipment, the all continuous miner system cost becomes $0.85/ton and the cost for the mixed system $1,65/ton.

Although the capital cost per ton of coal produced is higher for the longwall system, labor costs are reduced. Assuming that the

*This figure takes into account the amount of time the system is not in operation during this period because of maintenance, etc.

longwall and the continuous miner sections both require 10-person crews for their operation and that the size of the maintenance support staff is the same for both the all continuous miner mine and the combined longwall and continuous miner mine, the combined operation will require 80 fewer hourly employees to operate on a two shift per day basis. Based on a direct hourly rate of $9/hour and a fringe benefit rate of 35 percent, each of these 80 employees costs approximately $25,000 per year. Therefore, the total savings in labor costs for the mine configuration using the combined systems is $2 million per year, This sum is 14 percent of the difference in capital cost between the combined operation ($21 million) and the all continuous miner operation ($7 million). When the fact that the combined operation produces 900,000 additional tons of coal per year is factored in, then the payback period becomes of the order of 2 years.

There are a number of existing and planned underground mines on Federal coal leases that could use development strategies similar to that of the Deer Creek Mine. The Skyline Mine of Coastal States Energy Co., which is located near Price, Utah, is scheduled to open in 1982 with an initial production rate of 437,000 tons per year, This rate ultimately will be increased to 5.4 million tons per year. Over 40 percent of this production, 2.3 million tons, is scheduled for three longwall units ranging in capacity from 702,000 to 864,000 tons per year. Because of extreme variations in seam thickness and the presence of faulting on the property, problems which do not exist at the Deer Creek Mine, the balance of the annual production will be mined with continuous miners. It is estimated that 14 continuous miners will be required to produce their 3. l-million-ton share of the annual production.

Labor

As the above section shows, increased capital costs for longwall mining can be offset by reduced labor costs and increased production, Because the costs of capital and labor will be the major inputs into any mining system, both surface and underground, there always will be some tradeoff between the two, which will vary from mining system to mining system. However, several aspects of labor requirements for longwall systems differ from the labor requirements for room-and-pillar systems. These differences cannot be readily quantified in terms of direct cost.

Western coal mines usually recruit their miners from the general labor force. Some workers may come to the industry with a background in construction or some other related occupation, but few have any mining experience. Therefore, if a mine using longwall mining hires a new employee, there is frequently no need to retrain an individual recruited from room-and-pillar operations. This ability of the Western coal miner to adapt readily to the longwall mining environment has been noted by a number of companies. As indicated above in the discussion of the Deer Creek Mine, the production rate from its newly installed longwall face increased from 1,500 tons per shift to 2,500 tons per shift in little more than 3 months of operation. The only experiences longwall miners at the time the longwall unit was installed were the three shift foremen. The Coal Basin Mine longwall operation in western Colorado and the Sunnyside Mine in central Utah also have had good experiences with the installation of their first longwall units. Like Deer Creek, these mines have achieved production rates much higher than those obtained at many of the longwall units located in Eastern coal mines.

Another benefit of longwall mining from the point of view of the mine operator is the reduced labor requirement when compared to room-and-pillar systems. This factor is an advantage both with respect to finding enough qualified employees to staff an operation and in reducing the amount of infrastructure needed where a mine is remotely located and requires development of a supporting community infrastructure to serve employees, Since minable coal deposits in the West often are located in sparsely populated areas, the availability and the housing of employees are two major considerations. In the case of a mine such as Skyline, which is located in a large rural area of Utah that already has seen the expansion and development of a number of large mines, attracting skilled labor becomes a problem. Thus, reduction in the total number of operating employees required from 480 for a mine using all continuous miners to 340 for a mine using a combination of continuous miners and longwall units is significant,

There are other advantages to the mine operator of reduced overall manpower requirements. These include the reduced potential for personnel turnover, less need for employee training, and an overall reduction in personnel support costs. Operating with a smaller labor force also means that fewer people will be exposed to the hazards of underground coal mining per ton of coal produced. This will be discussed in greater detail in the section on health and safety,

Production and Productivity

As has been discussed in preceding sections of this chapter, production and productivity are related but separate operational considerations. An increased production rate is of interest to the operator who has the reserves to support large market commitments but who is not able to produce the coal required of these commitments because of deficiencies in the production system. In contrast, productivity is of interest to all mine operators, Productivity is usually discussed in terms of coal output in tons per unit of labor expended, but is equally applicable in terms of coal output per unit of machine time expended. Whether stated in terms of labor productivity or equipment productivity, the objective is to maximize coal production per unit of resource used.

The question of improved productivity and longwall mining has been addressed. In the discussion of the capital cost of longwall mining, the potential for improving labor productivity through the installation of longwall equipment was illustrated by two examples. It was also shown that even though the improved labor productivity was achieved through the use of longwall equipment which was more expensive than the continuous miners it replaced, the overall effect was a reduction in the total cost per ton of coal mined.

The underground coal mining industry in the United States has undergone significant change in the past 10 years. A 500,000-ton-per-year mine, formerly considered a large mine, is now considered of small to average size. With this change, production equipment and the scheduling of equipment have become more complex. Whereas a 50(),0()0-ton mine could operate with two to three continuous miners on a two shift-per-day schedule, mines such as the Skyline Mine discussed above would require 24 continuous miners to sustain its 5,4-million-ton-per-year production rate, Coping with the production scheduling in a mine where there are 24 operating sections which require the assignment of manpower, equipment, maintenance, and transportation is an extensive and demanding task. The Skyline operation is not unique in this respect. Other existing and planned underground mines on Federal leases that eventually will be producing in the 5-million-ton-per-year range include the Price River Coal Co. mine (formerly Braztah) in Utah and the Loma Complex in Colorado. In the 2-million- to 3-million-ton-per-year range there will be SUFCo in Utah, Mt. Gunnison in Colorado, Energy Development in Colorado, and potentially La Ventana in New Mexico, The mines in the l-million- to 2-million-ton-per-year range are even more numerous.

Nearly all of these mines will install longwall units, One of the major considerations in arriving at the decision to use longwall mining at these mines has been the need to achieve high production rates. A single longwall unit can produce 750,000 tons of coal per year. The longwalls at the Deer Creek Mine are producing in excess of 1 million tons per year per unit, The Wilberg Mine, a sister mine of Deer Creek, is installing a longwall unit that is rated at 3,000 tons per shift. This translates into 1.5 million tons per year, Coastal States Energy Co. is currently studying the feasibility of using longwall mining at its SUFCo Mine which is located on Federal leases near Salina, Utah. The minable seam, the Hiawatha, varies from 6 to 15 ft in thickness. However, the average thickness is 12 ft and with the exception of thinning on one part, the lease tends to maintain this average over extensive areas. There is little dip to the seam and little noticeable faulting. In sum, these conditions suggest that installation of at least one longwall unit to replace some of the existing 10 continuous miner units would simplify the operation and might reduce the cost of mining.

In summary, Western underground mines need to continue to pursue methods for increasing their production rates and improving their productivity. These combined goals will lower their unit mining costs and thereby enable them to compete more effectively with the coal mines in the Eastern United States and the large surface mines in the West. Other than reduced mining costs, an additional advantage of the increased production rates could be the ability to use unit-train transportation to move coal to markets and thereby recover some of the transportation cost penalty associated with supplying coal to Midwestern and Eastern markets.

Environmental

In the arid West, the impact of underground coal mining on the environment is generally less than that resulting from surface coal mining. Longwall mining can further reduce the environmental impacts normally resulting from room-and-pillar operations.

Subsidence from underground mining can take the form of either a wide-area lowering of the ground surface or sinkholes and fractures that break through to the surface. The results of several studies, conducted both in the United States* and Europe, indicate that longwall mining is most likely to result in wide-area subsidence and to cause little differential subsidence that can result in breaks in the ground surface. These studies also have indicated that surface subsidence is generally limited to an amount equal to one-half the thickness of the coal being extracted, although it can exceed 50 percent and can go as high as 90 percent of the seam thickness. For the thicker seam longwall operations, this would generally mean a subsidence of about 6 ft. A lowering of the surface elevation of this magnitude could be a problem in the Western United States and would have to be handled on a case-by-case basis. However, the areawide form of subsidence likely to result from longwall operations is preferable to the differential subsidence that is more likely to result from room-and-pillar operations,

*The Department of Energy has supported such studies at two mines with Federal leases, the La Ventana Mine in New Mexico and the Snowmass Mine in Colorado.

Health and Safety

Regardless of the type of mine, underground coal mining takes place in a hazardous environment. Fewer workers will be exposed to these hazards in a longwall operation than in other underground coal production met hods for a given level of production.

Because of the fundamental differences between room-and-pillar and longwall mining systems it is difficult to make a direct comparison as to which provides a healthier or safer environment for the worker. The basic hazards—coal dust, methane gas, spontaneous combustion, roof falls, bumps, and moving machinery in confined spaces—are present in both types of mining. In some cases there are tradeoffs in hazards, The control of excessive coal dust at the longwall face is a problem that must be solved, although there are some potential breakthroughs. On the other hand, however, the protection from roof fall hazards provided by longwall supports is superior to that available to the continuous miner operator.

Equipment advances that improve the underground mining environment with respect

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to worker health and safety will continue. However, the most direct results will be obtained through increases in labor productivity and a concomitant reduction in the number of workers that must be exposed to the dangers of underground coal mining.

CHAPTER 12

Revenues and Socioeconomic Impacts

Contents

List of Tables

List of Figures

CHAPTER 12

Revenues and Socioeconomic Impacts

Introduction

This chapter responds to the third of OTA's tasks under Public Law 94-377: calculation of potential Federal revenues from existing leases, It provides an estimate of revenues from rentals and royalties based on OTA's analysis of lease development and production prospects. The chapter also describes the various methods used by the Western coal States to distribute their share of mineral leasing revenues and discusses Federal and State programs for ameliorating the adverse impacts of energy development. Areas that potentially will be affected by expanded Federal coal development are identified.

Background

Rapid growth and its consequent social disruption have been characteristic of much energy development in the Northern Great Plains and Rocky Mountain regions. Large influxes of people, associated with the construction and operation of energy projects, have come to rural towns. Prior to this, many of the communities had stable or declining populations and economies based on service to agriculture.

With the sudden increases in population, local social structures have been hard pressed to meet the needs of the residents. Both public and private sectors have faced difficulties. Among the consequences of rapid growth have been:

- acute housing shortages with rapid cost escalations;
- inability of the public sector to provide services, such as sewer and water, in a timely way;
- dislocations in the private sector, such as business failures and labor shortages;
- manifestations of increased social stress, such as crime, truancy, and suicide;
- accompanying pressure on health, welfare, public safety, and mental health services;
- discontent expressed by both old and new residents; and
- high turnover rates and declines in productivity among employees of energy industries.

Financial shortfalls during the early stages of rapid growth have been particularly acute. These are called front-end financing difficulties. New public works, such as water or sewer systems, cannot be built quickly and they are expensive. In some instances, local voters have been reluctant to approve bond issues for public works, fearing that after the boom they will be left with a large debt. In other cases, towns have been limited by State statutes in the amount of debt they can incur.

As a result, most Great Plains and Western States have devised mechanisms to assist local governments in meeting both their front-end financing requirements and the other needs arising from rapid growth. Federal mineral leasing revenue payments are an important source of funds for impact assistance. A variety of types' of other Federal aid also are available.

Potential Federal Coal Leasing Revenues

Under section 35 of the Mineral Leasing Act of 1920, each State receives a share of the revenues derived from sales, bonuses, rentals and royalties from mineral activities on public lands within its borders.[1] Originally, a State's share was 37.5 percent; it was to be spent by the State legislature "for the construction and maintenance of public roads or for the support of public schools or other public educational institutions.'" Of the remaining revenues, 52.5 percent went to the Reclamation Fund to be used for water projects, and 10 percent went to the U.S. Treasury. { From 1920 to June 30, 1976, over $1.3 billion was distributed to the Western States for public roads and schools. There was no requirement that the areas most affected by mineral development on Federal lands receive priority in the allocation of the States' share.

In 1976, section 35 was amended to increase a State's portion of the revenues from **37.5** to **50** percent. The amount paid into the Reclamation Fund was reduced to 40 percent. In addition, purposes for which the State distributions could be spent were broadened. ' Each State legislature can now allocate mineral leasing revenues "giving priority to those subdivisions of the State socially or economically impacted by the development of minerals leased under this chapter for 1) planning, 2) construction and maintenance of public facilities, and 3) provision of public service."[5] This language established for the first time a specific priority for use of the revenues for impact assistance,

According to the Congressional Budget Office (CBO), a total of $210 million in Federal mineral royalty payments were distributed to the States in fiscal year 1979,') Most of these payments came from oil and gas leases; only $14 million (about 7 percent) came from coal leases on Federal lands in the West, according to CBO. Table 94 shows the total Federal coal production and total coal royalties reported by the Department of the Interior

[1]30 U.S.C. 191.
[2]Act of Feb. 25, 1920, c. 85, sec. 35, 41 Stat. 450.
'As part of its statehood entitlement, Alaska receives 90 percent of the Federal mineral leasing revenues generated within the State since it does not participate in the Reclamation Fund. See 30 U.S.C. 191. The Reclamation Fund was established by the Act of June 17, 1902, c. 1093, 32 Stat. 388, now codified at 43 U.S.C. 391, as amended. Moneys in the Fund are to be used for the reclamation of arid and semiarid lands through construction of dams, reservoirs, and irrigation projects, and for other specified purposes for the benefit of 17 Western States.

[4]The major amendments to sec. 35 (raising the Stale's share and broadening the purposes) were made by sec. 9 of the Federal Coal Leasing Amendments Act of 1976. Public Law 94-377, 90 Stat. 1087 (1976).
[5]30 U.S.Sc. 191.
'Energy Development, Local Growth, and the Federal Role, Congressional Budget Office, U.S. Congress, June 1980, p. 24.

Table 94.—Federal Coal Production and Royalty Revenues, by State: Fiscal Years 1979 and 1980

State	FY 1979 coal production (tons)	FY 1979 royalty revenues ($)	FY 1980 coal production (tons)	FY1980 royalty revenues ($)
Alabama	1,777	1,916	27,780	31,669
Colorado	7,401,530	3,852,839	8,562,862	7,115,564
Kentucky	59,637	62,385	9,219	10,830
Montana	7,964,316	1,298,325	10,345,255	2,065,885
New Mexico	4,660,225	1,048,550	6,546,224	1,472,900
North Dakota	589,079	134,622	1,418,129	272,272
Oklahoma	333,773	789,681	299,599	826,942
Utah	6,778,615	1,476,612	8,616,415	3,968,073
Washington	215,662	43,124	0	0
Wyoming	31,136,664	7,411,170	36,130,862	8,804,557
Total	59,141,237	16,119,225	71,958,165	24,568,692

SOURCE: U.S. Department of the Interior, *Federal Coal Management Report" Fiscal Year 1980,* 1981.

(DOI) for fiscal years 1979 and 1980; the States received one-half of these receipts,

Royalties are expected to increase substantially in the next decade, although the magnitude of the increase depends on the assumptions of the forecaster. CBO estimates that total payments from all types of mineral leases will reach $450 million to $500 million by fiscal year 1985. State shares of revenue from coal, CBO projects, will grow from $14.1 million in fiscal year 1979 to $65 million to $85 million by fiscal year 1985.

Budget figures prepared by DOI for fiscal year 1982 show an expected increase in total coal royalties from existing and new leases in all States from $24,6 million in fiscal year 1980 to $131 million in fiscal 1985, and to $792 million in fiscal 1990 (again the States would get half these revenues).[7] OTA's estimates of potential revenues from coal production on existing Federal leases also show a significant rise in payments (see below).

The increases can be attributed to several factors: the anticipated expansion of Federal coal production, the scheduled readjustments of existing leases to, and the issuance of new leases at the higher minimum royalty rate of 12.5 percent for surface mines required under the Federal Coal Leasing Amendments Act of 1976 (FCLAA).

OTA Estimates of Potential Revenues From Federal Coal Leases

Section 10 of FCLAA directed OTA to provide an estimate of the "receipts to the Federal Government" from existing Federal leases. OTA calculated the potential rentals and royalties for 1986 and 1991 based on OTA's estimates of the production prospects for Federal leases presented in chapter 6 of this report. The estimates include increased royalty rates on all leases that are due for readjustment over the next decade.

According to OTA's analysis, total Federal royalty revenues from existing leases in the six Western coal States should increase from $31.5 million in 1980 to $193 million to $215 million in 1986, and to as much as $336 million to $544 million in 1991 (depending on the rate of development of existing leases). The States will receive half these revenues. In the past, the amounts received as the States' shares of bonuses and rentals have been small compared to the front-end costs of meeting the impacts of coal development. Only when royalty payments started with commercial production have the States received significant benefits from coal lease revenues.

Bonuses

When Federal coal leases are offered competitively, the successful bidder pays a lump sum or "bonus" for acquisition of the lease as well as an annual rental and percentage royalty on production. Under the current bidding system, DOI establishes the rental and royalty before the lease sale and the lease is awarded to whoever offers the highest bonus bid. FCLAA requires that half of the leases for sale in any year be offered on a system of deferred bonus bidding, which allows lessees to pay the bonus in installments. No bid can be accepted for less than the fair market value of the coal, which is established before the sale by the U.S. Geological Survey (USGS).

No bonus is paid for the acquisition of a noncompetitive preference right lease. About half of the existing leases were issued through the preference right system and the more than 170 pending preference right lease applications (PRLAs) could result in new additional noncompetitive leases. When new leases are offered, the States receive half of the bonuses paid.

Table 95 shows the bonus payments received for Federal coal leases between 1954 and 1980. Since 1954 over $15 million has been received in bonuses for competitive leases. Of this amount, $1.4 million was paid after the 1976 amendments raising the State

[7] Personal communication, U.S. Geological Survey, Conservation Division, Royalty Accounting Section, February 1981.

Table 95.—Competitive Coal Lease Sales on Public Lands Fiscal Years 1954-1980 (acreage, bonus payments, average bonus per acre)

Fiscal year	Total acres	Total bonus payments	Average bonus dollar per acre
1954	400	$ 420	$ 1.05
1955	0	0	.
1956	4,316	4,317	1.00
1957	3,863	6,064	1.57
1958	15,375	19,176	1.25
1959	8,805	224,179	25.46
1960	4,358	9,055	2.08
1961	12,733	20,531	1.61
1962	38,976	202,404	5.19
1963	20,780	143,023	6.88
1964	10,768	39.532	3.66
1965	23,264	146,258	6.15
1966	44,894	753,727	16.79
1967	43,885	721,294	16.44
1968	88,037	3,077,736	34.96
1969	0	0	0
1970	18,493	370,395	20.03
1971	28,386	7,618,634	268.39
1972	0	0	0
1973	0	0	0
1974	3,989	390,776	97.96
1975	0	0	0
1976	0	0	0
1977	0	0	0
1978	574	31,380	54.69
1979	6,395	803,408	125.62
1980	7,817	582,369	74.50
Total	385.408	$15.164,678	$ 39.35

SOURCE:U.S Department of the Intertor,U.S.Geological Survey, Conservation Division, *Federal and Indian Lands Coal, Phosphate, Potash, Sodium, and Other Mineral Production, Royalty Inccome and Related Statistics. CY 1980.*

share to 50 percent. Throughout the period, individual bonus payments ranged from as low as $O.25/acre to hundreds of dollars per acre depending on when the sale was held and on the location and quality of the reserves.

Rentals

Estimated rentals from Federal leases are shown in table 96. The rentals are small compared to the revenues received from royalties. However, for States with large amounts of Federal lands under lease but with small amounts of production, rentals can be a significant component of their Federal revenue. Before passage of FCLAA, the amount of annual rental paid was subtracted from the royalties due. New leases and leases readjusted after August 4, 1976 do not allow rentals to be subtracted from royalties and require payment of annual rentals as well as production royalties. The amount of rental charged is set by the Secretary of the Interior before the lease sale and at readjustment. Most pre-FCLAA leases have rentals of $1.00/acre; minimum rentals for post-FCLAA and pre-FCLAA leases at readjustment are currently set at $3.00/acre, although some leases have rentals as high as $7.0()/acre.

Royalties

Federal coal royalties are based on either a straight fee per ton, generally between $0.15 and $0.22/ton for many pre-FCLAA leases, or a percentage royalty of the sale price per ton of coal produced with a statutory minimum of 12.5 percent for surface mined coal, The 1979 annual Federal coal management report noted the following about the percentage ad valorem royalty provision:

> The amount of money collected under a cents-per-ton royalty does not increase as the value of the coal production increases. During the 1970's, the Department shifted to percentage ad valorem royalties which provide that royalty payments to the Government will increase as the value of the coal increases. Conversely, the Government will share the risk with the lessee, receiving in ab-

Table 96.—Estimated Rental Payments for Federal Leases in 1986 and 1991

State	Number of leases	Total acres	1986[a] total rentals	1991a total rentals
Colorado	127	124,091	$253,886	$373,748
Montana	21	37,327	73,992	111,858
New Mexico	29	44,760	119,772	133,596
North Dakota	20	18,048	46,684	57,556
Utah	204	279,416	650,721	855,186
Wyoming	101	217,067	548,072	660,734
Total	502	720.709	$1,693,129	$2,192,678

a Rentals not reduced for portion of rentals credited to royalties due for unadjusted leases

SOURCE: Office of Technology Assessment

solute terms, less royalty money should the future price of coal decrease.

In calculating the potential royalty payments, OTA used the production estimates derived from the OTA analysis of the development prospects of Federal leases (ch, 6), These production estimates are expressed in ranges of production that reflect uncertainties based on markets, transportation availability, and the rate of mine construction. Consequently, royalty estimates reflect similar uncertainties, Because detailed long-term contract information and individual mine cost data were not available, OTA used a regional competitive mine-mouth price of coal in calculating future royalty payments. The actual mine-mouth sales price may be higher or lower than the regional figures used. The competitive mine-mouth prices were derived from an economic analysis done for OTA and are based on projections of the potential demand for Western coal. For the Hanna basin and Denver-Raton Mesa coal fields, which were not included in the economic analysis, OTA substituted an estimated mine-mouth price based on a review of DOE's national coal model supply curves and on OTA contractor surveys of mine operators, Table 97 shows the competitive mine-mouth prices used in the royalty calculations.

The estimates for all leases that are due for readjustment before 1991 reflect higher rental and royalty rates—$3.()()/acre rental and 12.5 percent surface and 8.0 percent underground royalties, Pre-FCLAA lease rentals were generally set at $1.()()/acre and royalties at $0.15/ton. The increases in royalty payments from readjustments will be substantial. For example, for underground coal mined at $20.0()/ton, the current royalty may be as low as $().15/ton; on readjustment, it would be raised to 8 percent of $l.60/ton—more than 10 times the previous level, For surface mined coal, the increase will also be substantial. Total Federal coal royalty payments in calendar year 1980 were about $32 million on total production of 69 million tons, Table 98 shows the potential Federal coal production, total royalty revenues, and State distributions estimated for 1986 and 1991.

Some existing underground mines have requested royalty reductions from the current minimum of 8 to 5 percent or lower under the provisions of section 39 of the Mineral Leasing Act and current regulations, [H] There is no statutory minimum royalty for underground

’30 U.S.C. 207

Table 97.—1986 and 1991 Competitive Mine-Mouth Prices by Federal Coal Production Regions (1979 dollars per ton)

Region	Btu/lb	1986 dollars/ton	1991 dollars/ton
Fort Union	6,000	6.00 Surface	6.00 Surface
Powder River basin	8,500	7.40 Surface	7.40 Surface
Hanna basin	10.500	16.50 Surface	16.50 Surface
Green River-Hams Fork:			
Wyoming	10,000	14.50 Surface 25.30 Underground	18.60 Surface 25.30 Underground
Colorado	10,000	20.00 Surface and underground	23.90 Surface and underground
Uinta	12,500	24.00 Underground	24.20 Underground
Southwestern Utah	11,000	11.80 Surface 24.00 Underground	11.80 Surface 24.20 Underground
San Juan	10,000	15.10 Surface and underground	15.30 Surface and underground

NOTE All prices are for steam coal

SOURCE Off Ice of Technology Assessment

Table 98.—Federal Royalties and State Distributions From Potential Coal Production on Federal Leases 1980 (actual) and 1986, 1991 (estimated) (1986 and 1991 royalties are in constant 1979.1980 dollars)

	1980[a]			1986[b]			1991[b]		
State	Federal lease production (millions of tons)	Royalty total (millions of dollars)	State share (millions of dollars)	Federal lease production (millions of tons)	Royalty total (millions of dollars)	State share (millions of dollars)	Federal lease production (millions of tons)	Royalty total (millions of dollars)	State share (millions of dollars)
Colorado	9.4	8.9	4.5	27	49	24	33-40	78-94	39-47
Montana	10.4	2.7	1.3	23-31	21-27	10-14	25-40	23-37	12-19
New Mexico	6.3	7	3.5	9-11	15-16	7-8	12-16[c]	21-28[c]	11-14[c]
North Dakota	0.6	(0.3)	0	about 6	about 4	2	6	5	2
Utah	8.7	4.5	2.5	26	48	24	34-66	64-122	32-66
Wyoming	33.4	8.7	4.4	113-150	57-71	28-36	133-238	145-258	73-129
Total (West).	68.8	31.5	16.2	204-250	193-215	95-108	245-405	336-544	168-277

Details may not add to totals because of independent rounding.

a U.S. Department of the Interior, U.S. Geological survey, Conservation Division, *Federal and Indian Lands, Coal, Phosphate,* Potash, *Sodium, and* Other *Mineral Production, Royalty Income, and Related Statistics, Calendar Year 1980,* June 1981.
b Royalty estimates assume timely readjustment of leases to a minimum royalty of 12.5 percent for surface coal and 8 percent for underground coal.
c Excludes about 8 million tons of Federal PRLA production and about $15 million in PRLA royalties.

mines as there is for surface mines. In some areas where underground mining costs are high, the royalty paid for underground mined coal can be higher per ton than that charged for surface mined coal. It is possible that, if many underground operations receive underground royalty rate reductions, total royalty revenues could be lowered in States such as Colorado and Utah where underground production is significant. But in return, since the royalty reduction is intended to allow the mine to be operated at a profit, it assures continued production, employment, and other revenues.

State Allocation of Federal Mineral Leasing Revenues

In response to the 1976 amendments and to local priorities for impact assistance, each Western State has established its own formula for spending Federal revenues. As the income from Federal production grows and local needs change, the States can alter these disbursement formulas. Current State practices (surveyed by OTA in 1980) are described in the following section.

Table 99.—Colorado Allocation of Federal Coal Royalties

State public school fund	25%
Water Conservation Board	10%
Mineral Impact Fund	15%
Counties (limited to $2(X),000 per county per annum; any excess to school fund) .	50%
Total ., ...	100%

SOURCE: Colo. Rev. Stat. 1973, 3463-101, 102, as amended.

Colorado

Colorado distributes its Federal mineral revenues in four different ways (table 99). The Mineral Impact Fund is dispensed by the Executive Director of the Department of Local Affairs, after a recommendation procedure involving local, regional and State entities. (State severance tax receipts are handled in the same way.) The Fund is used for planning, construction and maintenance of public facilities and for the provision of public services. Priority is given to "political subdivisions socially or economically impacted by the development, processing, or energy conversion of minerals" from lands leased from the Federal Government or subject to State severance taxes.[9]

A limitation of $200,000 per year on the direct county allotment means that major energy-producing counties receive much less

[9] Colo. Rev. Stat, 1973, §§34-63-102and 39-29-110 (1979 Supp.).

than 50 percent of the revenues. The excess goes into the public school fund, In fiscal year 1980, for example, Rio Blanco County generated $5.86 million and Moffat County $1.07 million of the $20.3 million that came back to the State. The $200,000 that each received amounted to 3.4 and 18.6 percent of the respective royalty revenues they generated. Six Colorado counties reached the $200,000 limitation; the spillover was $7.7 million (38 percent of the amount the State received), which raised the school revenues to $12.7 million (63 percent of the total receipts).

The original $200,000 per county limitation was enacted at a time when total mineral lease revenues were low and some Colorado counties were receiving far greater oil and gas revenues than their sparse populations could justify. These conditions have changed dramatically with substantial growth from coal development and expected change from proposed oil shale processing; as a result, legislation to raise the maximum has recently been proposed.

Wyoming

In Wyoming, revenues from the Federal mineral royalties are assigned according to a complex formula (table 100). About 19% percent is available for local assistance, including 21A percent for roads, 71/2 percent for public facilities, and 9¾ percent for communities.

The Wyoming Farm Loan Board allocates grants from the Impact Assistance Account and has the authority under the Joint Powers Act[10] to issue $60 million in loans to energy impacted jurisdictions. (See discussion on severance taxes, below, for a description of additional Wyoming mitigation programs.)

Utah

In Utah, 32% percent of the mineral leasing revenues are dedicated to a Community Impact Account (table 101). Established in 1977, it is a revolving fund for loans and grants to political subdivisions that are socially or economically impacted by mineral resource development.[11] The account is particularly important since Utah is the only Western coal-producing State without a coal severance tax. For the 1978-79 period, Utah received $13 million in mineral leasing moneys of which $4,2 million was allocated to the Community Impact Account. However, impacted communities requested more than $11 million. Most of the funds have been used for water and sewer projects in communities with critical growth problems.

The State requires that a majority of the funds given to the Board of Regents for higher education be spent for research, educational,

Table 100.—Wyoming Allocation of Federal Mineral Lease Revenues

State Highway **Fund** for construction and maintenance of permanent roads and highways in impacted counties	**2.25%**
Public School Foundation Fund.	**37.50**
State Highway Fund .,	**26.25**
University of Wyoming (pledged to bond issues).	**6.75**
Incorporated cities and towns for planning, construction or maintenance of public facilities or providing public services ($10,000 plus formula).	**7.50**
Wyoming Government Royalty Impact Assistance Account (Farm Loan Board)	**9.75**
(a) For impacted incorporated cities and towns, counties, joint powers boards without existing revenue sources; and	
(b) To fund planning, construction and maintenance of public facilities, provisions of public services or equipment purchases.	
School District Capital Construction Account.	10
	100%

SOURCE: Office of Technology Assessment

Table 101 .—Utah Allocation of Federal Mineral Lease Revenues

Community impact account revolving fund	32.5%
Board of Regents-institutions of higher learning	33.5%
State Board of Education.	2.25%
Geological and Mineralogical survey	2.25%
State Water Research Laboratory	2.25%
General fund appropriation	27.25%
Total	100°/0

SOURCE: Utah Code Ann. 1953, 63.51-1 through 4

[10] Wyo. Stat. §§9-1-l 29 through 136.

[11] Utah Code Ann. 1953, §§53-7-l and 2: 65-1-64 and 65; and 65-1-1 15(1979 Supp.).

and service programs to benefit communities economically or socially affected by mineral leasing activities.

Other Western States

The other Western States distribute funds by a variety of formulas. Montana currently provides 62.5 percent of its Federal royalties for schools and 37.5 percent for highway improvements. How much of this money ends up in energy impacted communities is difficult to determine. New Mexico designates virtually all of its Federal mineral revenues to the General Permanent Fund for the public school textbook fund and other purposes. North Dakota similarly places all its royalties in the general fund for distribution to public schools.

Federal Programs To Assist Energy-Impacted Communities

Loans Against Future Leasing Revenues

Section 317(c) of the Federal Land Policy and Management Act of 1976[12] authorizes the Secretary of the Interior to make loans to States against their share of anticipated mineral leasing receipts for any prospective 10-year period. The loans, intended to address front-end financing problems, are to be made specifically for relieving the socioeconomic impacts associated with Federal mineral development activities. The program has yet to be extensively used by the States. ”

Payment in Lieu of Taxes (PILT)

The Payment in Lieu of Taxes Act of 1976[14] provides Federal funds to local units of government as compensation for taxes that they cannot levy on the tax exempt Federal lands within their boundaries. With regard to coal development, annual payments are made to local jurisdictions that contain land administered by the Bureau of Land Management (BLM) or the U.S. Forest Service. The PILT funds are allocated under a formula based on acreage, population, and revenue producing programs on public lands such as timber, grazing and mineral development. Although not so designated, the funds are often used for energy impact assistance. ’s Total (coal and other) payments under PILT in 1979 were $105 million and in 1980 amounted to approximately $108 million (table 102).

An important feature of PILT is that the payments given to local governments are reduced by the amount of Federal mineral lease revenues redistributed to these jurisdictions by the States. That is, any lease revenues that flow directly to local areas are deducted from the per-acre PILT payments. This arrangement serves as an incentive for States to use mineral royalties for purposes other than returning them directly to impacted jurisdictions. But it makes no difference to the local

[12] Publjc Law 94-579; 90 Stat. 2743; 43 U.S.C. 1747.

[13] According to the CBO study, note 6 *supra*, the loan Program met with initial objections from the executive branch because of the low interest rates provided, In 1978, the act was amended to allow higher rates, thus removing the major objection. A total loan level of $212 million was authorized through fiscal year 1982, although no funds have been appropriated, and $40 million of the authorization expired in fiscal year 1979. See Public Law 95-352, sec. l(c), 92 Stat. 515, Aug. 20, 1978.

[14] Public Law 94-565.

[15] PILT payments are made almost exclusively to county governments, since cities and towns generally do not contain BLM or Forest Service lands.

Table 102.—Payments in Lieu of Taxes by State

State	FY1980 payment
Colorado	$7,507,361
Montana.	8,078,067
New Mexico	9,589,751
North Dakota	571,552
Utah	8,146,654
Wyoming	6,550,736

SOURCE: Department of the Interior.

governments, since they receive equal sums, either from Federal PILT payments or from the State's share of mineral lease receipts.

Abandoned Mine Reclamation Funds

The Surface Mining Control and Reclamation Act of 1977[16] provides for annual grants to States to help develop, administer, and enforce statewide reclamation programs. The programs are for Federal and non-Federal lands disturbed by coal mining. The act also establishes Federal and State abandoned mine reclamation funds, financed primarily by revenue derived from a reclamation fee of $0.35/ton of surface-mined coal and $0.15/ton of underground-mined coal, or 10 percent of the gross value of the coal, whichever is less.

Fifty percent of the reclamation fees collected annually in any State must be allocated to the State's abandoned mine reclamation fund. This in turn must be used to reclaim any land mined for coal and abandoned (or otherwise left in an inadequate reclamation status) prior to 1977. If all such land in a State has been reclaimed, the State may use its 50 percent of the fees for construction of public facilities in communities impacted by coal development.[17] The State must certify, and the Secretary of the Interior agree, that there is a need for such facilities and that the moneys available under the Mineral Leasing Act or the PILT payments are inadequate for such construction.

Since the Western States until recently have had little large-scale coal mining, they have fewer abandoned, unreclaimed coal mines than the Eastern States. Therefore they are more likely to qualify to use their 50 percent for public facilities in coal impacted communities, This could be a major source of funds for Western States with approved reclamation programs.

[16]Public Law 95-87, 91 Stat. 445, 30 U.S.C. 1201 et seq. Title 4 of the act established the Reclamation Fund.

[17]30 U.S.C. 1233(g)(1).

"601" Program

A Federal program for energy impacted areas was established by section 601 of the Powerplant and Industrial Fuel Use Act of 1978.[18] Administered by the Farmer's Home Administration in the Department of Agriculture, it provides funds for planning assistance and acquisition of land for housing and public facilities in communities affected by coal or uranium development. Individual States have not received much assistance from section 601 programs because of the relatively small appropriation ($20 million in 1979 and $50 million in 1980), the statutory limitations on the use of the money, and the large number of States that have applied for assistance.

Other Federal Programs

BLM is supporting a project on the social effects of the Federal coal management program in the West.[19] The project will develop a guide for social impact assessment to help fill existing data gaps and remove some theoretical uncertainties about community disruption. Because it is designed to improve the generic process, the project should, in the long run, significantly improve the social and economic mitigation aspects of Federal leasing efforts.

A variety of other programs, not directed at energy *or* mineral development, is also available to State and local governments; however, only a few deal with socioeconomic problems. According to various authors, from 30 to 165 programs have been useful to boomtown communities.[20]

[18]Public Law 95-620; 92 Stat. 3323 (1978).

[19]BLM Social Effects Project, Mountain West Research, Inc., Billings, Mont.

[20]The following reports provide information useful to impacted communities:

An Assessment *of Oil* Shale Technologies (ch. 10), OTA, GPO stock No. 052-00340759-2 (Washington, D. C.: Government Printing Office, 1980).

Energy Development in the Western United States—Impact on Rural Areas, Murdock and Leistritz (New York: Praeger Publishing,1979).

Report to the President-Energy Impact Assistance, Energy Impact Assistance Steering Group (Washington, D. C.:

State Programs

Each State has developed ways of providing technical and financial assistance to energy impacted areas. In addition to traditional revenue sources such as sales, income, and excise taxes used to support general programs, Western States have relied on three specific sources for energy impact mitigation. These are Federal mineral royalties, State severance taxes, and bonding authority. In most States, severance tax revenues contribute the most aid.

Severance Taxes

A severance tax maybe broadly defined as a special levy assessed at flat or graduated rates on the extraction of natural resources. Severance taxes are distinguished from other taxes by their imposition on the removal of the natural resource rather than on the resource itself. Legally, severance taxes are generally held to be excise rather than property taxes and, as such, are not subject to the constitutional requirements placed on property taxes of uniformity and equality. There has been much controversy on the nature, level, and distribution of severance taxes.

Some of the arguments cited in support of severance taxes include:

- Natural heritage.—A State's natural resources are an irreplaceable heritage of the people of the State. A severance tax is compensation for a portion of the irretrievable loss of this wealth.
- Conservation of natural resources.—If a tax is high enough, the increased price of the extracted mineral should slow the rate of resource exploitation and stimulate the substitution of alternative technologies and/or renewable resources.
- Internalization of socioeconomic costs, —The significant public costs associated with large-sale mineral development can be internalized by levying a severance tax. If the tax is shifted to consumers, a price for the resource can be established that reflects a truer cost of production, both public and private.
- Capture of economic rent.—According to the concept of economic rent, the finite nature of natural resources results in a market price that includes a portion representing pure surplus that can be taxed away without affecting consumer price, production levels, or allocation of resources. For example, in passing the Montana Coal Severance Tax Act, the Montana Legislature declared that "coal in Montana, when subbituminous and recoverable by strip mining, is in sufficient demand that at least one-third of the price it consumes at the mine may go to the economic rents of royalties and production taxes."
- Statewide sharing of tax benefits. —Since mineral development often occurs in less populated rural areas, more populous regions sometimes feel they deserve a larger share of the benefits from this development. In addition, areas away from the immediate energy-producing regions can be affected by energy development. For example, between 1975 and 1978, approximately 75 percent of Colorado's growth in mining employment occurred not in the outlying resource areas but in the Denver metropolitan area. A severance tax can help spread benefits throughout the State.

State Income From Severance Taxes

Colorado, Montana, New Mexico, North Dakota, and Wyoming impose severance taxes. Of the coal-producing States, only Utah does not; however, Utah does impose a mining

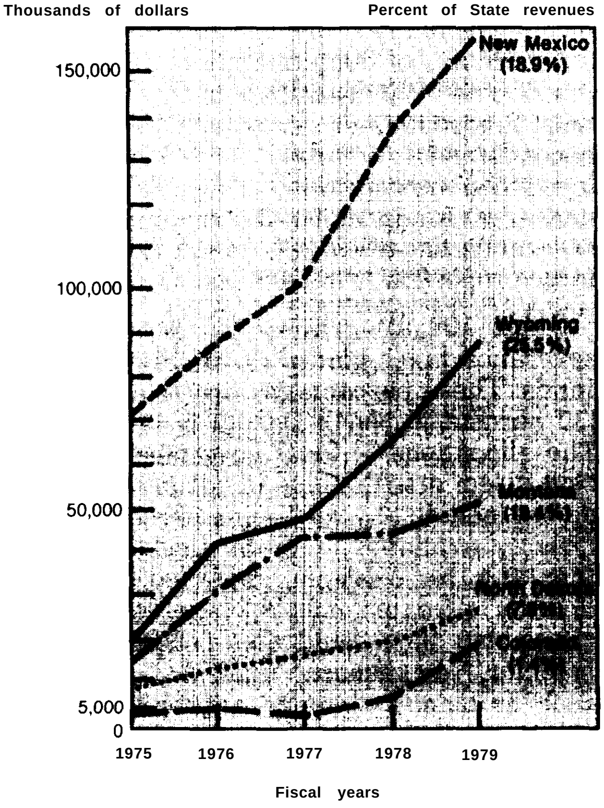
Continued from p. 355.

DOE/IR-0009, 1978).
Mitigating Adverse Socioeconomic *Impacts* of Energy Development, Denver Research Institute (Denver: DRI, 1977).
Federal Assistance for Energy Impacted Communities, Mountain Press FRC (Denver: MPFRC, 1979).
The Direct Use *of Coal* (ch. 6), OTA, GPO stock No, 052-003-00664-2 (Washington, D. C.: U.S. Government Printing Office, 1979).

occuaption tax on various minerals (excluding coal). Figure 53 shows severance tax income from all minerals, not just coal, and the portion of total State revenues contributed by severance taxes. Wyoming ranks highest in percentage (25 percent) of State revenue derived from severance taxes. New Mexico received the largest amount ($159 million in fiscal year 1979), although only 13 percent was from coal. A common trend is the increase over the pastI 5 years in funds available to the States through these taxes.

In general, coal severance taxes are calculated either as a flat rate of production or as a percentage of net or gross value of the coal produced. Table 103 shows the different bases currently used for assessing severance taxes. The 30-percent rate in Montana is the highest of the Western States and its consti-

Figure 53.—Total Severance Tax Revenues (all minerals)



SOURCE: Office of Technology Assessment.

Table 103.—Coal Severance Taxes

Colorado		
Coal—Surface	$0.63/ton	
Underground	$0.315/ton	
Adjusted by wholesale price index.		
Montana		
Heating quality (Btu/pound)	Surface mining	Underground mining
Under 7,000	$0.12 or 20% of value	$0.05 or 3% of value
7,000-8,000	$0.22 or 30% of value	$0.08 or 4% of value
8,000-9,000	$0.34 or 30% of value	$0.10 or 4% of value
over 9,000	$0.40 or 30% of value	$0.12 or 4% of value
Resource indemnity trust tax (all minerals): $25.00 plus **0.5** percent of gross value of product if in excess of **$5,000.**		
New Mexico		
Coal—Steam coal	$0.57/ton	
Adjusted by consumer price index escalator (in 1981 total tax is $0.73 per ton)		
North Dakota		
Coal—Steam coal	$0.50/ton	
Adjusted quarterly based on wholesale price index.		
Wyoming		
Coal	**10.50/0** of gross value	

SOURCE: CERI, *Mineral Severance Taxes in Western States; A Comparison,* pp. 5-15 and Office of Technology Assessment survey of State Revenue Agencies, January 1981

tutionality has been challenged by mining companies and coal consumers. On July 2, 1981. the U.S. Supreme Court ruled that Montana could impose a severance tax this high without violating either the Commerce Clause or the Supremacy Clause of the United States Consitution.[21]

Allocation of Severance Taxes Revenues

Table 104 summarizes the distribution of coal severance tax revenues. New Mexico does not follow a specific allocation formula; instead, all its revenues are placed in the Severance Tax Bonding Fund. Each year the legislature authorizes the issuance of bonds for a variety of projects, including impact assistance. Any portion of the fund that is not pledged to the principal and interest on outstanding bonds is deposited in the Severance Tax Permanent Fund. The Community Assistance Authority makes recommendations for the issuance of bonds for projects in areas affected by mineral and energy develop-

[21]Commonwealth Edison Co. v. Montana, No. 80-581, July 2, 1981 (slip opinion).

Table 104.—Allocation of Coal Severance Tax Revenues

Category	Colorado	Montana	New Mexico[a]	North Dakota	Utah[b]	Wyoming
General fund	O% (1981 and after) (20% 1980)	19.00%		30%		19.0%
Permanent trust fund	50% (1981 and after) (35% 1980)	50.00%		15%		23.9%
Local government	50%[c]	8.75%	10%	35%[d]		19.0%[e]
Other		22.25%[f]		20%[g]		38.1 '/O[h]

[a] Reallocated annually by legislature

[b] Utah has no severance tax

[c] 15 percent of local government severance tax fund is automatically distributed to affected jurisdiction in proportion to the number of mine employees who reside in the county's unincorporated areas. Remaining 85 percent is distributed at discretion of Executive Director of Department of Local Affairs, with advice from an energy impact assistant advisory committee.

[d] The Coal Development Impact Fund is administered by Coal Development Impact Office that makes discretionary grants to impacted communities

[e] The Coal Impact Fund, administered by the Farm Loan Board consisting of key State officials, makes grants to local governments in special districts affected by coal production for financing water, sewer, highway, road and street projects.

[f] This category includes 5 percent for school equalization, 10 percent education trust, 0.5 percent county planning, 2.5 percent alternative energy research, 1.25 percent renewable resource development, 25 percent parks, historical and cultural sites and 0.5 percent library commission.

[g] Distributed to counties on the basis of the proportion of the total State coal production In that County

[h] This is comprised of 14.3 percent in water development fund, 95 percent in highway fund, and 14.3 percent in capital facilities fund which is used for State government facilities, school buildings, and community colleges.

ment, and $10 million is allocated annually for the specific purpose of making grants to impacted communities.

Colorado gives energy developers a credit against their severance taxes for certain approved contributions made to local communities to assist with preventive efforts before a project begins operation.

Colorado, Montana, North Dakota, and Wyoming place a percentage of their coal severance tax revenues in trust funds. These funds are intended to compensate future generations for depletion of nonrenewable resources. The purposes of the funds are stated in general terms; the most common areas for investment are the reestablishment and diversification of the economic base in anticipation of the day when the mines are exhausted. The funds also can be used to redress any long-term environmental consequences of prolonged coal mining, They are in part a response to the boom and bust cycles that have historically characterized mineral development in the West.

Four of the seven Western coal-producing States—Wyoming, Montana, New Mexico, and North Dakota—have passed constitutional amendments establishing permanent mineral trust funds. The term "permanent"' means that a three-fourths vote of both houses of the legislature is necessary before the principal can be disbursed for any purpose. Such precautions are designed to preserve the integrity of the principal. Colorado has a permanent trust fund established by statute that has no restriction on payments from its principal; however, the State has not yet spent any of the principal. In most States, the income from investment of the permanent trust funds is either deposited directly in the general fund or otherwise made available for legislative appropriation. Thus, these permanent trust funds, unlike the remainder of the severance tax revenues, do not contribute a large proportion to impact assistance.

Table 104 also shows the percentage of severance taxes placed in the State general funds. These percentages are relatively low (30 percent in North Dakota is the highest). The allocations to local governments represent direct distributions to communities, and do not include any remaining percentages indirectly available to these jurisdictions. In Montana, for example, impacted towns are directly allocated only 8.75 percent of revenues, but they could also receive indirect benefits from general fund disbursements, such as county planning appropriations, or cultural and historic site moneys.

In addition to mechanisms to dispense revenues, Wyoming has created several governmental agencies to help mitigate the socioeconomic impacts. In 1974, the legislature passed the Joint Powers Act[22] to encourage various levels of government to cooperate in the financing of public facilities. Local governments (e.g., cities, counties, school districts) can join together to become eligible for Joint Powers Loans.

In 1975 the legislature created the Wyoming Community Development Authority (WCDA) to help alleviate housing shortages.[23] It is designed to compensate for the lack of funds in the private mortage lending market. WCDA is authorized to issue up to $250 million in bonds that provide assistance through private lending institutions and through purchase of mortgages in areas of capital shortage. The program became fully operational in 1979 and more than $200 million in WCDA bonds were committed as of the end of 1979.

Several other programs are valuable to jurisdictions with rapid growth. For instance, if a school district is nearing the limit of its bonded indebtedness and faces expenses beyond its financial capacity, it may apply to the Farm Loan Board for emergency construction funds, A $2 million account within the Permanent Trust Fund is reserved for this purpose. In addition, the legislature has granted counties the authority to institute an additional l-percent sales tax.[24] This tax must be distributed on the basis of population; as a result, cities and towns with increased population get a greater proportion of the revenue than counties.

State Energy Facility Siting Programs

While most States analyze the physical environmental effects of siting major energy facilities, only a few have developed programs to deal directly with the socioeconomic aspects of this siting. Montana and Wyoming are two that have mechanisms specifically addressing such impacts. The primary aim of these programs is to ensure that industry participates in appropriate mitigation efforts.

The Wyoming Industrial Development Information and Siting Act was passed in 1975 largely in response to the social and economic conditions in boomtowns such as Rock Springs and Gillette. ” The act requires that, prior to construction, major energy developers predict likely social and economic impacts and commit themselves to a number of monitoring and mitigation strategies. An Industrial Siting Council has broad latitude to determine compliance with an elaborate set of criteria. The council must approve all projects with a total cost of over $63 million and certain other projects with the potential for substantial community or environmental impact.

The Montana Major Facility Siting Act[26]) has a checklist of socioeconomic criteria requiring an applicant to give consideration to impacts on the population already in the area, on the population attracted by construction and operation of the facility, and on public services and facilities. Coal mines producing more than **500,000** tons per year, most electric generating facilities, and synfuels plants must obtain a siting certificate.

The Montana Board of Natural Resources and Conservation has discretion to place conditions on the siting certificate. For instance, in the case of the application for generating units 3 and 4 at Colstrip, the Board asked Montana Power to set up a training program for Northern Cheyenne Indians wishing employment in the construction and operation work force.

[22] Wyo. Stat. §§9-1-129 through 136.
[23] Wyo. Stat. §§9-18-101 through 123.
[24] Wyo. Stat. 5$39-6-412.

[25] Wyo. Stat. §§35-1 2-101 through 121.
[26] Mont. Rev. Codes Ann. §§75-20-101 through 1205 (1979 Supp.)

Effects of Expanded Federal Coal Production

Industrial development in sparsely populated rural regions inevitably brings changes in the established social patterns. These changes are seen as mixed blessings. On the one hand, a larger tax base, the expansion of retail services, and an improvement in public services are viewed as positive. On the other, housing shortages, crowding of facilities such as schools, and locally high inflation are seen as negative impacts. Residents respond in a variety of ways. Some welcome the changes as indications of prosperity; others lament them for the loss they bring to the earlier ways of life.

Whether communities are able to adapt to rapid growth depends on a complex set of elements, many of them site-specific. In any case, the combined efforts of private entities, especially the energy developers, and public agencies, particularly local and State governments, are necessary to deal with the changes.

The effects of expanded Federal coal leasing will depend on the interaction of many factors. These include:

- Magnitude of the growth.—The direct and indirect population influx from a large energy project may double or quadruple the size of a small rural community.
- Pace of the development. — Energy-related growth occurs suddenly and progresses rapidly, frequently with major impacts in the first few years of the development. Rural communities often are ill-prepared for this surge.
- Fluctuating nature of the growth.—During the construction period there may be large increases and decreases in population. The permanent operating force often is significantly smaller than the construction one. Communities must prepare for large temporary populations, especially in the case of powerplant construction.
- Uncertainty. —The timing of develop ment is often uncertain because of changes in project economics and financing, shifts in State and Federal policy, and the risks associated with large energy projects. The unpredictable future of development makes initial investment in community facilities and services risky and difficult.
- Condition of existing municipal services and facilities, —Existing facilities have little excess capacity or elasticity. In addition, they may require extensive upgrading. The condition of many services and facilities is such that replacement may be required; and an isolated location usually means higher construction costs.
- Availability of fiscal and other aid.—Improvement of public services and facilities must occur during the early stages of industrial expansion; this takes place before an enlarged tax base is established. The front-end financing problem is usually one of timing rather than a long-term shortfall, since the increase in public revenues may ultimately exceed the total cost of municipal expansion. That the problem is one of timing rather than net loss in the long term, however, does not make it less severe.
- jurisdictional problems.—A new energy facility and the increased tax base it generates are frequently located in one political subdivision while the population settles in another. For example, energy facilities may be located in the unincorporated portions of counties (which derive revenues from the project), while the majority of new workers settle in adjacent towns (which legally cannot share in these revenues).
- Private sector [commercial) infrastructure.—As in the public sphere, private sector services often require expansion; small towns generally have only basic commercial establishments. Lack of

capital. absence of experienced entrepreneurs, and competition with energy industries for labor and supplies can all contribute to delay in the expansion of local businesses.

- Characterstics of the region. —Some areas have experienced past booms and busts and are accustomed to their disruptive effects; others have not and the residents may be unprepared for boomtown problems.
- **Concurrent expansion of other** indus- *tries in the same* location.—Many of the most severe problems have been associated not with coal mining, but with major powerplant construction. Although major disruptions in sparsely populated and homogeneous communities could occur from the number of mines and ancillary activities necessary to support large-scale coal production, the biggest problems will come from total energy development. Thus, the greatest potential for major socioeconomic dislocations exists where more than one energy-related development is expected.

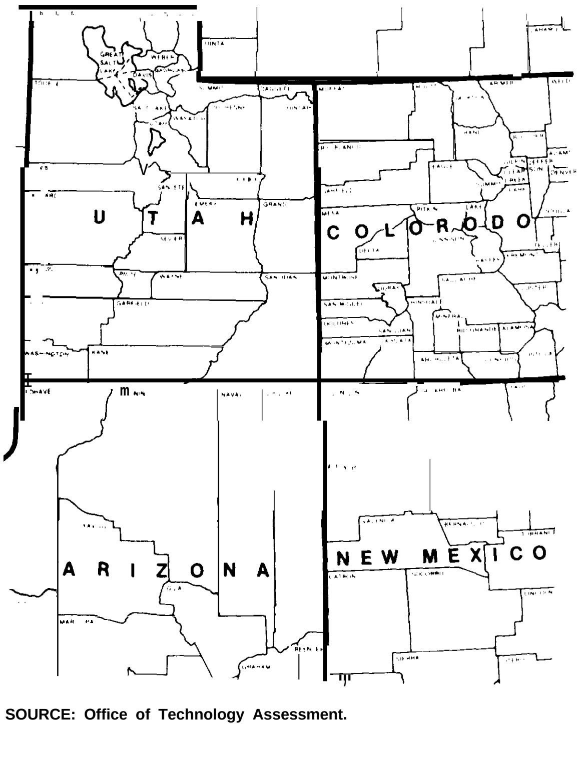
The remainder of this chapter examines the potential for adverse social and economic consequences in the coal development regions studied by OTA. The State task force reports, from which the following discussions are drawn, include consideration of how socioeconomic conditions could influence Federal coal development. The task forces concluded that socioeconomic and community conditions would not be a significant constraint on the development of existing leases. This is because industry is concerned with problems such as labor turnover, and State and local governments have experienced some adverse consequences of coal-related growth. As a result, prospective developers and impacted communities will probably take appropriate steps to deal with any emerging problems,

Colorado

To handle the negative effects of energy development, Colorado has adopted an impact mitigation strategy involving local citizens, regional Councils of Governments, and a statewide office to coordinate efforts. The strategy has been successful in developing both public and private solutions to growth problems. Nevertheless, some communities have already experienced negative consequences from coal development, and the potential for future difficulties exists. OTA's estimates of potential production (see ch. **6)** indicate that areas already experiencing problems are the most likely to face future difficulties.

The northwest and west-central are such regions (fig. 54 and table 105). For example, all eight of the proposed new lease tracts in Colorado are within **25** miles of Craig. The erection of two new coal-fired units at the Craig station, possible building of a synthetic fuels plant, and construction of major regional reservoirs in the next 10 years could

Figure 54.—Counties of the Rocky Mountain Study Area



SOURCE: Office of Technology Assessment.

Table 105.—Demographic Characteristics of Selected Counties in Colorado, Utah, and New Mexico

County	Total population[a] 1970	Total population[a] 1980	Percent change 1970 to 1980[a]	Land area[b] (mi^2)	People per mi^{2b}	Percent 65 years and older[b]	Total acreage of land in farms[b] (1,000 acres)	Percent of all land in farms[b]	Average size of farms[b] (acres)
Colorado									
Delta	15,286	21,225	38.90/o	1,154	15	18.90/o	282	38.1 0/0	338
Elbert	3,903	6,850	75.5	1,864	3	11.0	2,106	90.6	2,106
Garfield	14,821	22,514	51.9	2,996	6	10.5	397	20.7	1,161
Gunnison. . .	7,578	10,689	41.1	3,110	3	4.6	262	12.7	1,638
Jackson	1,811	1,863	2.9	1,622	1	8.4	470	45.3	5,114
Las Animas .	15,744	14,897	– 5.4	4,794	3	15.6	2,118	69.0	5,205
Moffat	6,525	13,133	101.3	4,743	2	8.3	1,146	37.8	4,604
Montrose. . .	18,366	24,352	32.6	2,238	9	11.0	429	30.0	558
Ouray	1,546	1,925	24.5	540	3	9.7	157	45.5	2,097
Pitkin	6,185	10,338	67.1	973	9	2.8	49	7.8	1,016
Rio Blanco. .	4,842	6,255	29.2	3,263	2	8.3	480	23.0	2,907
Routt	6,592	13,404	103.3 %	2,330	4	6.30/o	650	43.60/o	2,391
Utah									
Carbon.	15,647	22,179	41 .7%	1,476	12	10.3%	363	38.4%	2,523
Emery	5,137	11,451	122.9	4,439	1	9.9	219	7.7	589
Garfield	3,157	3,673	16.3	5,158	1	10.6	120	3.6	668
Kane	2,421	4,024	66.2	3,904	1	9.4	205	8.2	1,831
Sevier.	10,103	14,727	45.8%	1,929	6	18.1%	199	16.2%	483
New Mexico									
Colfax	12,170	13,706	12.6%	3,764	3	12.4%	2,269	94.2%	8,561
McKinley . . .	43,208	54,950	27.2	5,454	9	4.4	3,363	96.4	28,264
Rio Arriba . .	25,170	29,282	16.3	5,843	5	8.0	1,468	39.3	2,531
Sandoval . . .	17,492	34,799	98.9	3,714	6	7.6	790	33.2	3,249
San Juan . . .	52,517	80,833	53.9%	5,500	12	5.3%	1,912	54.3%	4,698

a 1980 Census of population and Housing: Advance *Reports,* **U.S. Bureau of the Census March 1981 (PHC80-V).**
b 1975 data, City and County Data Book, U.S. Bureau of the Census, 1977

SOURCE: U.S. Bureau of the Census.

add to the population influx from coal development.

Craig has been handling growth for some time (the population of Moffat County has doubled since 1970) with the help of State impact assistance funds and professional city management. However, the amount of money that is returned to Craig from Federal royalties and State severance taxes is small compared to the revenues generated, and this disparity is a sore point with local leaders,

Nearby, at Hayden, the problem of fluctuating growth cycles can be seen. Expecting new coal miners and construction workers to settle there, the town expanded its waterworks. But the growth failed to materialize, and now Hayden residents are having trouble paying the debt from this expansion. Similarly in Craig, the population dropped from layoffs a t mines and from completion of unit 2 at the powerplant, but the voters have had to decide on a referendum for a $7 million bond issue to double the current capacity of the water system.

Meeker illustrates the difficulties of planning ahead for growth. Work force estimates for possible oil shale projects range from 2,200 to 3,600 people per facility; including families and secondarily induced service personnel, over 10,000 people could conceivably move to the town. If the oil shale endeavors proceed according to some plans, the area could experience a 400- to 600-percent increase in population by 1985.27 The uncertainties associated with oil shale development, however, make it difficult to prepare for this growth, Concurrent expansion of coal production would add to these difficulties,

Rangely illustrates the problem of jurisdictional mismatches. This town, already the center for oil and gas development, is ready to absorb some new residents. Workers will come from the Federal oil shale tracts in Colorado once a road is completed. They are also apt to come from coal and oil shale developments in Utah, since Rangely is closer to these sites than Vernal, Utah. In this case, Rangely will bear the costs of accommodating the workers without the benefit of tax revenues from the properties.

Rio Blanco County has recently completed an agreement with Western Fuels Associates for impact mitigation. The company's proposed Deserado mine near Rangely will supply coal for a powerplant at Bonanza, Utah. Under the agreement, support will be provided for expansion of water and sewer facilities, schools, highways, and both municipal and county services (planning, medical, fire protection, recreation, and other services). The arrangements are based on the expected arrival of 1,500 new residents in the Rangely area. About $15 million will go for mitigation; this is 5 percent of the projected $300 million cost of the development,

In recognition of the fact that unpleasant living conditions lead to low productivity and high worker turnover, many energy developers have taken the initiative to help communities. Industry has contributed to the provision or upgrading of facilities and services, has assisted with housing development for workers, has prepaid taxes, and has taken other steps such as offering training programs for local workers. For example, early in 1981, Northern Coal Co. announced it had arranged to build 18 apartments in Meeker as temporary housing for its employees. Approval has been given for a 104-lot development, sponsored by industry, for permanent housing. In addition, Northern Coal has prepaid $318,500 in severance taxes to help fund municipal improvements.

“Meeker’s population was 1,597 in 1970 and 2,356 in 1980.

Utah

Utah has two major coal regions with Federal leases— the Uinta region including Carbon, Emery, and Sevier Counties in the central part; and the Southwestern region encompassing Garfield and Kane Counties in southern Utah (fig. 54 and table 105).

The central area has historically been a coal producing region. Mining and related construction have been, and remain, the major economic activities, In the past, conditions in the coal market have had a direct effect on these counties. From 1950101970, during depressed market times, they experienced declining populations. Since 1970, with an improved market, they have had significant growth: for instance, mining employment increased over 200 percent in Emery County in the first half of the 1970’s.

There is disagreement over whether or not increased coal development will cause socioeconomic problems in central Utah. For example, in preparation of the DOI final environmental impact statement for coal development, the most extensive criticisms revolved around the social impact analysis.

The disagreements were also reflected in the OTA task force for Utah that reviewed the data for this assessment, The task force generally assumed that impacts could be dealt with adequately and community requirements would not be a factor discouraging mine development. However, county commissioners and other local residents interviewed by OTA staff expressed concern about the capability of the area to absorb and support development without major disruption of existing communities and displacement of their ways of life; they cited loss of irrigated cropland and higher real estate assessments among their concerns.

The State government has adopted a policy to promote dispersed development. The intention is to spread the benefits and impacts of coal development more evenly and thus avoid the adverse consequences of more concentrated growth.

Development of coal leases in the Alton and Kaiparowits coalfields in southern Utah would require new or expanded facilities. The area is sparsely populated and rural, without large communities. Agriculture and tourism are the principal industries. A significant portion of the work force needed to operate coal mines would have to be brought into the area; new communities would have to be constructed to provide for the miners, support personnel, and their families.

One of the greatest concerns about coal development in Utah is the potential for change in the character of the communities. Many believe the entry of new residents would alter the generally homogeneous religious and cultural composition of the present social fabric. This perception of “outsiders” is a relatively recent development, and may stem in part from the residents’ greater recognition of the magnitude of the development being proposed. The view residents have of activities elsewhere may also be contributing to their concern. In southern Utah the impression of the Price area (in the central part of the State) is that of a boomtown, similar to Rock Springs, Wyo. Many southern Utah residents feel that substantial changes in Price’s character have taken place and they wish to avoid similar alterations. The possible changes in community composition or way of life are also a predominant concern behind much of the local opposition to the proposed MX missile system.

In sum, the potential for socioeconomic changes appears high in Utah, assuming that planned coal development proceeds. At the same time, there is widespread disagreement as to whether these would be undesirable changes. Central Utah has been an historic coal mining area; booms and busts are not unknown to these towns. Southern Utah is sparsely populated and coal development would require establishing a different social and economic infrastructure to meet the needs of a larger and more , diverse population.

New Mexico

Like Utah, New Mexico has the potential for extensive socioeconomic changes, and the probability of these changes being negative appears high. The State recognizes the possible effects of industrial expansion on local government and has funded studies and projects in preparation for energy development. Large-scale expansion of coal mining and construction of powerplants or synthetic fuel projects in the San Juan basin could severely strain existing social and economic institutions. The problems would be particularly severe in remote coal regions where there are now few or no community facilities and services (table 105; fig. 54),

OTA’s analysis (see ch. 6) indicates coal production could double or triple in the Star Lake-Bisti region (assuming the completion of the railroad). The towns of Cuba, Grants, and Milan would be most affected by the new mines and the construction, operation, and maintenance of the proposed Star Lake Railroad. Uranium and oil and gas development are also planned, and considerable public concern about the impact of uranium mining on the community of Grants has been expressed.

The town of Cuba is located near several new Federal coal developments; it is the closest community to the proposed La Ventana, Star Lake, and Black Lake mines. Cuba lacks the capability to provide the services needed to handle the expected growth. For example, water quality in this region is poor and its availability for domestic use is limited. Transporting water to Cuba from other parts of the State has been under study. The town is currently burdened with financial obligations, including $651,000 in outstanding bonds, that limit its ability to underwrite new projects.

The Farmington, Bloomfield, and Aztec areas expect a construction boom that is projected to peak in 1985-86. A State Commission has established as high priority the repair and construction of new roads from the Farmington area to Cuba needed to handle the expected increase in coal traffic. In Farmington a housing shortage exists and water for residential use is not plentiful.

Because of the landownership patterns in New Mexico, off-reservation Indian lands and communities will be affected by the development of existing Federal leases. Mitigation efforts will require, in addition to State government participation, involvement of Tribal governments and local Indian pueblo councils, as well as consultation with DOI'S Bureau of Indian Affairs.

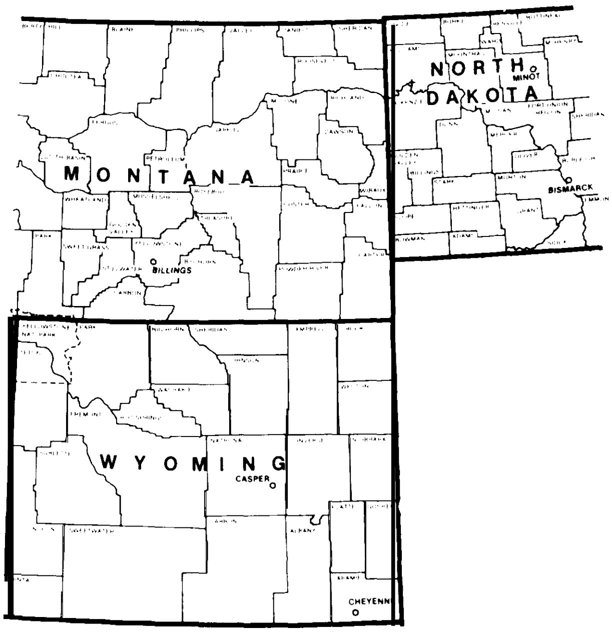
Wyoming and Montana

OTA focused on two regions in Wyoming and Montana: the Powder River basin, and southern Wyoming. A map of these areas and the nearby communities is found in figure 55; demographic indices are in table 106.

An early study of the socioeconomic impacts of increased coal development in the Northern Great Plains[28] reached the following conclusions:

- Population increases attributable to coal development will be large, and attendant problems will be compounded because such increases will be both rapid and unevenly distributed.
- Most communities in the Northern Great Plains are not prepared to deal with the magnitude of change attending regional coal development.
- The rapid influx of population will cause a proportionally greater increase in demand for services because newcomers often have higher expectations for services than native residents.
- Public service requirements will increase at a much faster rate than revenue collection, especially in the early years of development. The service areas of particular concern are housing, health care, and education.

Figure 55.—Counties of the Great Plains Study Area



SOURCE" Off Ice of Technology Assessment.

These expectations were confirmed by subsequent experiences in the region. For example, Rock Springs, located in Sweetwater County in southwestern Wyoming, was the subject of a classic study of boomtown phenomena.[29] The population increased from 18,931 to 36,900 from 1970 to 1974. The ability to provide municipal and other local services declined markedly. The ratio of doctors

[28] Northern Great Plains Resource Program, 1974. This extensive study covered the five States of Montana, Nebraska, North Dakota, South Dakota, and Wyoming; it was funded in large part by the Department of the Interior.

[29] John S. Gilmore, and Mary K. Duff, Boom town Growth Management: A Case Study of Rock Springs—Green River, Wyo. (Boulder, Colo.: Westview Press, 1975).

Table 106.—Demographic Characteristics of Selected Counties in North Dakota, Wyoming, and Montana

County	Total population 1970	Total population 1980	Percent change 1970 to 1980[a]	Land area[b] (mi²)	People[b] per mi²	Percent 65 years and older[b]	Total acreage of land in farms[b] (1,000 acres)	Percent of all land in farms[b]	Average size of farms[b] (acres)
North Dakota									
Bowman . . .	3,901	4,229	8.40/o	1,170	4	10.3%	712	95.6%	1,873
Burke	4,739	3,822	– 19.4	1,119	3	16.2	661	92.4	986
Grant	5,009	4,274	– 14.7	1,666	3	10.7	1,091	95.6	1,230
Hettinger. . .	5,075	4,275	– 15.8	1,134	4	11.3	758	99+	1,244
McLean	11,251	12,288	9.2	2,065	6	14.3	1,236	93.5	935
Mercer ., . . .	6,175	9,378	51.9	1,042	6	12.1	608	91.2	944
Oliver	2,322	2,495	7.5	721	3	7.6	419	90.9	1,072
Ward	58,580	58,392	– 0.3	2,044	30	7.4	1,256	96,0	881
Williams . . .	19,301	22,237	15.20/o	2,064	9	10.60/0	1,241	93.90/0	1,122
Wyoming									
Campbell. . .	12,957	24,367	88.1 “/0	4,756	3	5.0%	7,069	95.5 ”/0	7,069
Carbon.	13,354	21,898	64.0	7,905	2	7.9	2,628	51.9	10,905
Converse . . .	5,938	14,069	136.9	4,281	2	9.6	2,440	89.0	8,904
Johnson . . .	5,587	6,700	19.9	4,175	1	15.2	2,127	79.6	8,645
Sheridan . . .	17,852	25,048	40.3	2,532	8	14.7	1,471	90.8	3,226
Sweetwater.	18,391	41,723	126.90/o	10,429	3	6.40/o	1,764	26.40/o	16,640
Montana									
Big Horn . . .	10,057	11,096	10.3%	5,023	2	7.20/o	2,648	82.50/o	5,212
Madison . . .	5,014	5,448	8.7	3,528	2	13.1	1,191	52.8	3,103
Musselshell.	3,734	4,428	18.6	1,887	2	15.1	1,210	99+	5,628
Rosebud . . .	6,032	9,899	64.1 0/0	5,037	2	6.50/o	3,009	93.30/0	8,798

[a] 1980 census of population and Housing, *Advance Reports,* U.S. Bureau of the Census, March 1981 (PCH80-V)
[b] **1975 data.** *City and County Data Book,* **'U.S. Bureau of the Census, 1977.**
SOURCE: Bureau of the Census.

to population changed from 1:1,800 in 1970 to 1:3,700 in 1974 (in contrast to an average statewide ratio of 1:1,100). In 1974, county schools were short an estimated 128 schoolrooms; approximately 1,397 homesites had no municipal services; and 4,599 mobile-home spaces were needed. Caseloads in mental-health clinics increased eightfold. Crime rates increased by 60 percent between 1972 and 1973 alone, while police services remained relatively constant.

Other towns affected by nearby coal mining include Forsyth and Colstrip, Mont.; and Sheridan, Gillette, and Douglas, Wyo. Some of them have been better able to handle the impacts than others; and the mining company mitigation efforts have been different in each community.

Colstrip was originally developed by the Montana Power Co., for its workers at the Rosebud Mine and the Colstrip Power Plants. Workers at Peabody's nearby Big Sky Mine had to commute daily from Forsyth, about 40 miles away. In the last few years, Montana Power has begun to transfer ownership of the town of Colstrip, and Big Sky Mine workers are purchasing houses there.

Sheridan, Wyo., has grown from mining developments around Decker, Mont. Workers at the East and West Decker and Spring Creek mines live in Sheridan although they work in

Montana. Sheridan has taken this growth in stride, although the county has difficulty obtaining sufficient funds for its general budget to meet operating expenses.[30] Increased housing costs, in large part from energy development, have created hardships for elderly residents on fixed incomes.[31]

Gillette, too, has had difficulty. During an oil boom in the 1960's, the adverse psychological effects of rapid growth were so pronounced that they came to be known as the "Gillette syndrome." Now, with coal development, careful planning appears to be controlling some of the problems seen in the earlier period. A new town, built to house workers at mines south of Gillette, was able to accommodate a population of 1,400 within 3 years after construction began.[32]

Douglas, Wyo., which already has experienced rapid growth, will have substantial additional impacts with the development of new projects, and Rock Springs continues to show boomtown symptoms, Workers for the Jim Bridger, Black Butte, and Stansbury mines live there. The Wyoming Industrial Siting Council has asked industry to reevaluate the impacts of the Jim Bridger Mine and Power Plant on Rock Springs. The community is seen as an undesirable place to live and turnover is growing at the mines. The development of a better environment in Rock Springs "is a matter of good business, " according to industry sources.[33]

In summary, Wyoming has experienced some of the most extensive social and economic changes from energy development, Different communities have responded in different ways; some have become boomtowns, others have coped with rapid growth without excessive disruption. The State has developed a wide array of mitigation strategies to assist the affected counties and communities.

[30] D. Pernula, "But What Happens When Coal's in Montana and Growth's in Wyoming?" The Western Planner 1(7):9 September 1980.

[31] P. Primack, "Expanding Energy Town Narrows Life for Elderly, " High Country News, 11(19):1 Oct. 5, 1979.

[32] R.E. Huff, "Wright's Success Reflects Commitment and Coopera tion, " The Western Planner 1(7):15 (1980).

[33] "Persona] communication from J. Larsen, 1980.

The greatest potential for additional coal production from existing leases is in the Wyoming portion of the Powder River basin (see ch. 7), Campbell and Converse Counties, therefore, are the most likely to experience additional growth, and possible disruption from Federal coal development.

North Dakota

Coal mining on Federal land in North Dakota occurs in the Fort Union region in the western portion of the State. Most of the major mining operations are located in the four west-central counties of McLean, Mercer, Oliver, and Ward (see fig. 55). In recent years, Federal, State, and local governments have been major employers (28 percent of the population in 1975), with agriculture next (25 percent), Large farms and ranches, producing wheat and cattle, are characteristic. The largest urban area is Bismarck; small towns with stable populations are found throughout this part of the State (see table 106).

Rapid growth has already come to the towns of Beulah and Hazen, Energy developers in the Beulah area have pooled resources to provide housing for incoming workers, and Bismarck and nearby Mandan (within an hour's drive of the major lignite developments) have absorbed some of the new population,

There generally has been little local opposition to industry expansion in those areas where lignite mining and powerplant construction have already taken place (e. g., Oliver and Mercer Counties). This may be because much local income comes from the nearby mining operations. Negative public reaction has been pronounced in Dunn County, however. The combination of public opposition to the siting of Natural Gas Pipeline Co. 's (NGPL) planned gasification facility in the Dunn Center area and the lack of available air quality increments at Theodore Roosevelt Park led to NGPL's decision to abandon the project. To date, no large coal related facilities have been located in the immediate vicinity. The opposition of Dunn

County residents is shared by some Native Americans on the Fort Berthold Indian Reservation directly to the north of NGPL's proposed site.

Almost all of the existing Federal leases are in already developed areas (Mercer and Oliver Counties), Social and economic impacts are not likely, therefore, to affect the further development of Federal coal resources. This situation would change with the leasing of new tracts in previously undeveloped parts of the State. For example, the western edge of the State is an area where social and economic impacts from several ventures could accumulate. Oil and gas exploration is taking place here now, and although the operations are well removed from existing Federal lease areas, the potential exists for future problems.

Oklahoma

Federal coal leases are located in four counties in the east-central region of Oklahoma. Economic conditions are poor in this part of the State. A continuing decline in coal production since 1950 combined with a failure of other industries to flourish in this region has led to economic stagnation. Most civic leaders and many residents would welcome a rejuvenation of the coal industry .34

[34]This is documented in BLM's public participation file and was supported by individuals in private industry and in Federal and State agencies contacted during OTA's survey of the Oklahoma coal industry.

However, as discussed in chapter 6, the prospects are not encouraging for extensive development of coal on Federal land in Oklahoma during the 1980's.

Development of the Federal leases could require underground mining in many instances. However, surface mining has dominated the Oklahoma industry for the past two decades, and few local miners have had extensive underground experience. Consequently, the initiation of mining by the companies holding Federal leases would probably require the recruitment of workers from outside the State.

Four mines are currently operating on Federal leases, Any increase in population that might result if additional Federal leases were developed over the next 10 years would not impose an unmanageable burden on community services. The population of many towns is still smaller than when coal mining was more extensive. Most elementary and high schools could increase their enrollments without building new facilities or hiring new teachers, and health and recreational facilities are adequate. However, in several communities that have been hard hit by economic recession, commercial and residential buildings have deteriorated and would require extensive repair or replacement.

CHAPTER 13

Patterns and Trends in Ownership of Federal Coal Leases and PRLAs 1950=80

Contents

List of Tables

List of Figures

CHAPTER 13

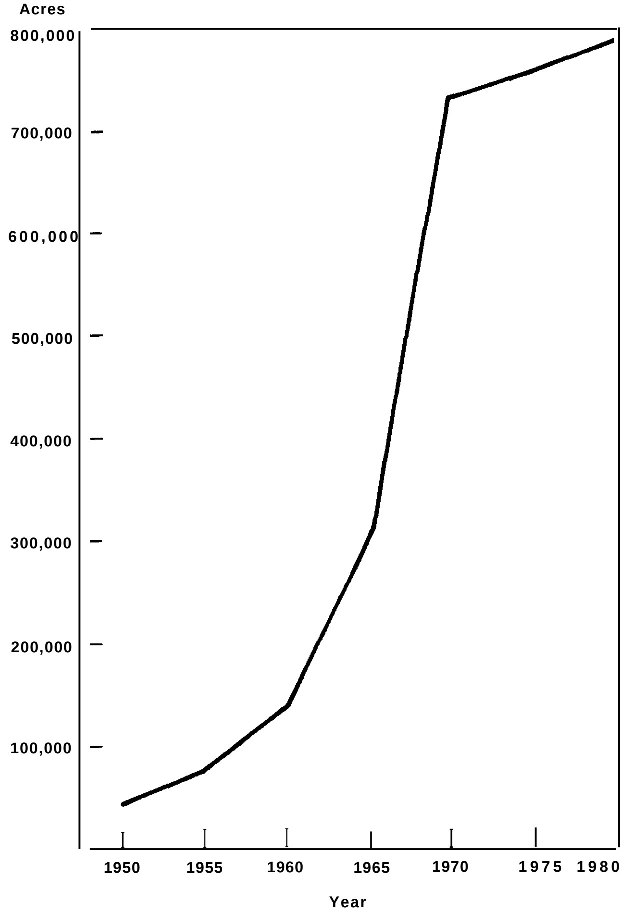
Patterns and Trends in Ownership of Federal Coal Leases and PRLAs 1950-80[1]

The Federal coal leasing program makes Federal coal land available for mining by the private sector. Hence, the amount and location of leased land helps define the extent of the coal reserve base of the industry. Figure 56 shows the total number of acres under Federal coal lease from 1950 to 1980, The regions with leased coal lands in the West are shown in figure 17 and discussed in chapter 4.

This chapter summarizes the results of a study of the ownership histories of each of the 538 Federal coal leases and 176 preference right lease applications (PRLAs) in existence as of September 30, 1979. * The chapter identifies the participants in the coal leasing program between 1950 and 1980 and examines the changing ownership patterns of Federal coal leased to the private sector. The ownership histories of companies, grouped according to similar business activities or business organizational structures, are considered separately.

The principal data used for this chapter were case histories of the legal ownership of the titles to each Federal lease and PRLA. ** This information was collected from primary sources, principally serial books and case files maintained by State offices of the Bureau of Land Management. From this data, lists of all owners of leases and PRLAs at each of seven analysis dates were developed and the holdings of each owner tabulated. The analysis dates were January 2 of the years 1950, 1955, 1960, 1965, 1970, 1975, and 1980. Next, each present and past owner

Figure 56.—Total Acres of Federal Coal Under Lease 1950-80



SOURCE Office of Technology Assessment

[1]For further information on this subject, see the OTA Technical Memorandum, *Patterns and Trends in Federal Coal Lease Ownership 1950-80*, OTA-TM-M-7, March 1981. The Technical Memorandum is available from the Superintendent of Documents, U. S. Government Printing office, Washington, D.C. 20052, at $4.00 per copy. Its GPO stock number is 052-003-00799-1.

*In its ownership work, OTA did not analyze leases or PRLAs that were relinquished prior to Sept. 30.1979 or the few leases issued in late 1979 or in 1980. Thus, the coal lease acreage totals in this chapter and the total number of leases considered in this chapter differ slightly from the totals in the rest of the report, which include a 11 leases in existence on Sept. 30, 1980. A complete presentation of the methodology and findings of the ownership study is contained in the OTA Technical Memorandum referenced above.

**OTA examined the owners of record of leases and PRLAs. It did not study companies participating in the leasing program in other capacities such as "designated operators" of mines working under contract to lessees or "sublessee" investors, of Federal coal during this period was classified according to its principal line of business activity (if an individual or an independent corporation] or by the business activity of its controlling interest or interests (if a wholly owned subsidiary or a joint venture). In addition, all present and past owners were categorized according to their type of business organization structures. Detailed and separate analyses were then done for any business activity category and business organization structure that controlled at least 5 percent of all land under lease or PRLA at one of the dates listed above. Individual analyses were also done for any company that did not clearly fall into an identifiable business category but nonetheless controlled 5 percent of leased land or land under PRLA at one of the dates selected for analysis. Remaining owners were grouped in an other category.

Thirteen categories of business activity groups holding leases and 10 categories of PRLA owners were identified and studied. Also, four types of business organization categories were identified for both lease and PRLA owners. The business activity categories for leaseowners and PRLA holders are as follows:

Business Activity Categories Defined by **OTA**

Leaseholders*	PRLA holders
Electric utilities	Unincorporated individuals
Energy companies	Energy companies
Peabody Coal Co.	Natural gas pipeline companies
Steel companies	Kemmerer Coal Co.**
Independent coal companies	Metals and mining companies
Oil and gas (minor) companies	Electric utilities
Unincorporated individuals	Oil and gas (minor) companies
Natural gas pipeline companies	Landholding companies
Nonresource-related diversified companies	International Geomarine and Coal Conversion Co,
Kemmerer Coal Co.**	“Other” lessees
Metals and mining companies	
Landholding companies	
“Other” lessees	

*The categories include 10 industries, two individual companies that were classified as distinct business categories for various reasons and an other category for the remaining lessees, Each of the 13 business categories controlled or controls at least 5 percent of all land under lease al some time between 1950 and 1980.

**In March, 1981 Kemmerer Coal Co. was purchased by Gulf Oil Corp.

Ownership by Business Activity Category

Tables 107 and 108 and figure 57 summarize data on the relative and absolute growth and decline in leaseholdings by the 13 business activities defined and studied by OTA. Table 109 provides similar information for the 10 categories of PRLA owners. These tables and the figure show that:

- The electric utilities, major energy companies, oil and gas (minor) companies, natural gas pipeline companies, and nonresource-related diversified companies have all increased their Federal coal landholdings significantly since 1965 both in absolute and relative terms.
- Independent coal companies and unincorporated individuals dominated coal leasing in the 1950’s and the first half of the 1960’s but their leaseholdings, expressed as a fraction of the total land under lease, have steadily declined since 1950. Individuals are still the dominant class of PRLA holder.
- Peabody Coal Co. and Kemmerer Coal Co. have played important and long standing roles as large individual leasing parties.
- Steel and metals and mining companies were early leasing participants, but steel industry influence has declined steadily in relative terms since 1955, although the acreage held by the steel industry has steadily increased since 1950. Metals and mining company leaseholdings have varied widely, due in part

Table 107.—Number of Acres and Percent of Total Leased Land Held by Business Activity Category

	1950		1955		1960		1965		1970		1975		1980	
	Acres held (#)	Land leased (%)	Acres held (#)	Land leased (%)	Acres held (#)	Land leased (%)	Acres held (#)	Land leased (%)	Acres held (#)	Land leased (%)	Acres held (#)	Land leased %	Acres held (#)	Land leased (%)
Electric utilities	0	0	2,000	3%	8,263	6%	45,363	15%	132,038	18%	142,077	19%	163,259	21%
Energy companies	0	0	0	0	0	0	9,491	3	132,274	18	138,409	18	155,024	20
Peabody Coal Co.	0	0	0	0	0	0	(6,251)	(2)	(59,121)	(8)	(68,923)	(9)	62,009	8
Steel companies	4,993	12	14,817	19	19,888	14	34,158	11	46,114	6	49,448	6	60,015	8
Independent coal companies	14,584	35	25,022	33	41,557	29	77,273	25	78.297	11	58.837	8	55,410	7
Oil and gas (minor) companies	0	0	0	0	0	0	2,080	1	26,911	4	42,193	6	45,926	6
Unincorporated individuals	11,129	27	17,618	23	25,678	18	41,475	13	78,995	11	66,515	9	43,215	5
Natural gas pipeline companies	0	0	0	0	0	0	0	0	0	0	32,522	4	36,317	5
Nonresource-related diversified companies	0	0	0	0	0	0	4,610	1	10,015	1	12,580	2	35,675	5
Kemmerer Coal Co.[a]	475	1	1,752	2	6,849	5	18,504	6	33,793	5	33,988	4	32,191	4
Metals and mining companies	5,009	12	5,009	7	9,266	6	17,708	6	107,504	15	118,300	15	17,620	2
Landholding companies	1,360	3	4,576	6	11,504	8	13,411	4	43,581	6	26,225	3	4,661	<1
"Other" lessees	2,907	7	3,240	4	18,288	13	39,134	13	41,153	6	37,051	5	77,861	10

NOTE Uncategorized lessees hold less than 2 percent of land under lease at any analysis date

Numbers might not add to 100 percent because of the holdings of uncategorized lessees

Numbers in ( ) tabulated in metals and mining category (1970 and 1975) or in independent coal company category (1965)

	1950	1955	1960	1965	1970	1975	1980
Uncategorized	1035	1,915	2,453	5,147	2643	6,848	1845
Lessees	2%	3%	2%	2%	< 1%	1%	< 1%

[a] **In March 1981,** Kemmerer Coal Co was purchased by **Gulf Oil Corp.**

SOURCE Off Ice of Technology Assessment

Table 108.—Changes in Federal Coal Lease Ownership Because of Recent Major Corporate Ownership Changes

Corporate ownership change[a]	Number of of leases involved	Number of of acres involved	Change in business activity category	Change in business organization category
Kemmerer Coal Co. purchased by Gulf Oil Corp.	26	37,191	From Kemmerer Coal Co. to energy companies	No change
St. Joe Minerals Corp. purchased by Fluor Corp.[b]	1	280	From metals and mining companies to nonresource-related diversified companies	No change
Energy Fuels Corp. purchased by Getty Oil Corp.[c]	5	4,521	From independent coal companies to energy companies	From independent corporations to subsidiaries
Belden Enterprises purchased first by Grand Mesa Coal Co., which was bought by Eastern Gas and Fuel Associates jointly with Nicor, Inc.	1	42	From independent coal companies to "other" and natural gas pipeline companies	From independent corporations to multicorporate entitles
CONOCO, Inc. purchased by E I du Pent de Nemours & co	31	43,442	From energy companies to non-resource-related diversified companies	No change
Sum: (IO°/. of total leased Federal coal acreage)		80,476		

[a] **The table does not reflect lease ownership changes that have occurred because of the assignment of leases after Jan 1, 1980 and which, consequently, are not reflected in any tables, figures or text in this chapter**

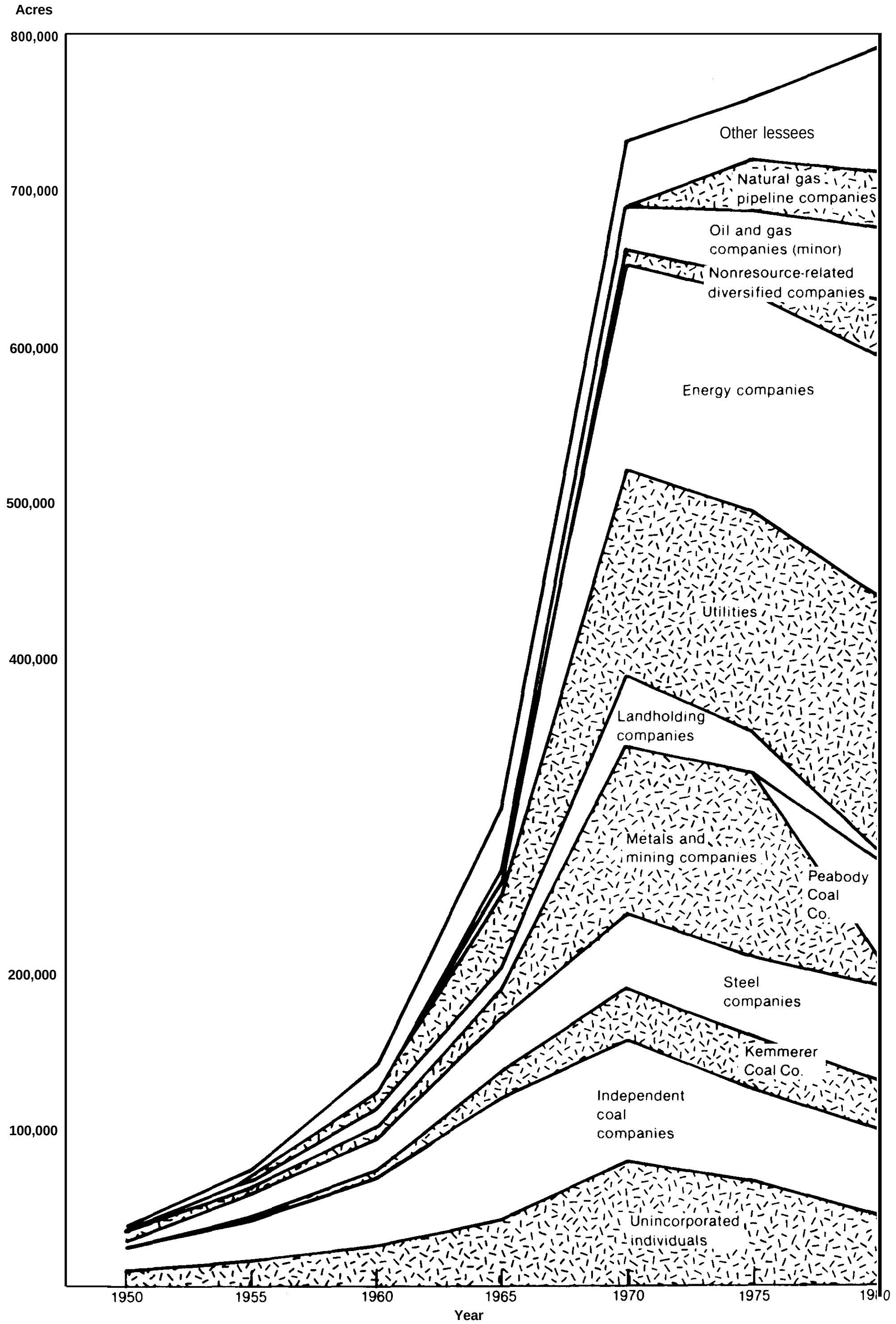
[b] **The lease involved is held by a subsidiary, Anchor Coal Co**

[c] **Getty now holds the leases by a** subsidiary, Getty Mining Co.

[d] The leases involved are held by Consolitdation Coal Co

SOURCE Off Ice of Technology Assessment

Figure 57.— Number of Federal Coal Acres Under Lease by Business Activity Category, 1950-80



sOURCE: Off Ice of Technology Assessment

Table 109.—Number of Acres and Percent of Land Under PRLAs Held by Business Activity Category

	1955-65	1970	1975	1980
Unincorporated individuals	UP to 5,890 (loo%)	147,022 (46%)	115,317 (28%)	80,559 (20%)
Energy companies	—	22,008 (7%)	30,738 (7%)	65,784 (16%)
Natural gas pipeline companies	—	0 (0%)	21,045 (5%)	46,867 (12%)
Kemmerer Coal Co.[a]	·	33,190 (10%)	39,160 (9%)	39,160 (10%)
Metals and mining companies	·	17,278 (5%)	39,461 (9%)	36,514 (9%)
Electric utilities	—	0 (0%)	3,113 (1%)	34,658 (9%)
Oil and gas companies (minor)	—	25,786 (8%)	34,375 (8%)	33,845 (8%)
Landholding companies	—	23,519 (7%)	28,639 (7%)	5,120 (1%)
Int'l Geomarine and Coal Conversion	—	43,878 (14%)	46,084 (11%)	0 (0%)
Other lessees	—	9,874 (3%)	57,427 (14%)	58,216 (14%)
Unknown	—	260 (less than 1%)	260 (less than 1%)	3,077 (1%)

Total percentages might differ from 100 percent because of rounding.

a In March 1981, Kemmerer Coal Co. was purchased by Gulf Oil Corp.

SOURCE Office of Technology Assessment

to the 1977 sale of Peabody Coal Co. by Kennecott Copper Corp.

- Independent land companies played a significant role in leasing in the 1950's and 1960's, but they have largely liquidated their holdings over the past decade.

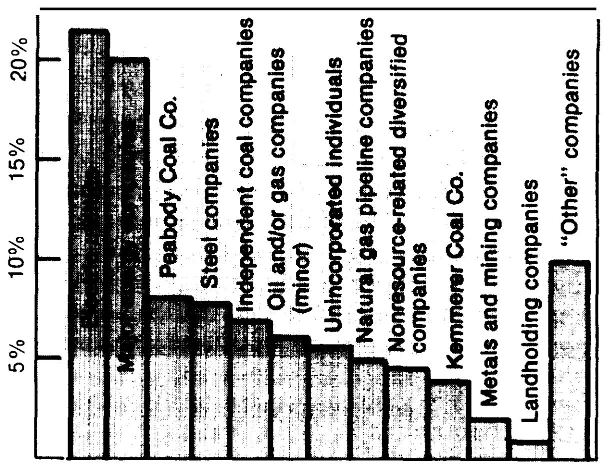
Table 107 and figure 57 also summarize the absolute changes in leaseholdings that have occurred over the past 30 years. They show the steady increase in acreage held by the steel companies, independent coal companies, and unincorporated individuals through 1970, followed by the slow decline in the holdings of the latter two groups since then. Table 107 and figure 57 also illustrate how the significant but relatively modest increases in the holdings of these three groups during the 1960's compare to the more substantial acquisitions of some new entrants to leasing in that period, (Table 108 summarizes the major changes in corporate ownership that have occurred since early 1980 that affect the acreages held by the major coal leaseholding categories shown in table 107.)

Figure 58 shows that the leaseholdings of the 13 major business activities ranged, in 1980, from 21 percent of all land under held by the electric utilities, to less than 1 percent, held by independent land companies. The major energy companies hold 20 percent of leased acreage. With the exception of the utilities and the major energy companies, all the categories hold less than 10 percent of leased coal acreage.

Eight business activity groups currently hold at least 5 percent of all land included in PRLAs. A ninth holds over 1 percent (see fig. 59). Each group also appears on the list of major leaseholding categories, although there are differences in the rank ordering of the groups in the two cases. Individuals hold a larger share of land under PRLAs (20 percent) than any other category. Individuals are followed by major energy companies and natural gas companies and then by four industries each of which holds between 8 and 10 percent of land under PRLAs.

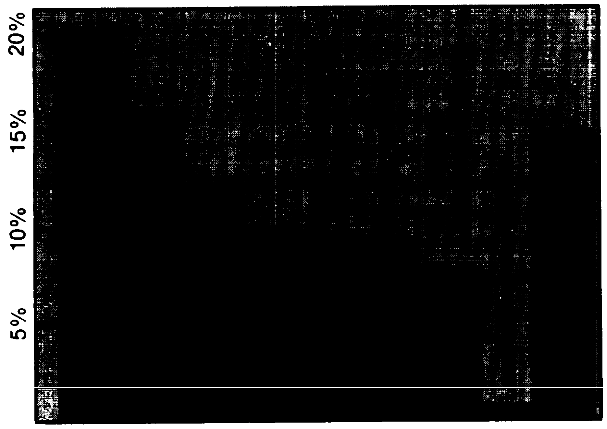
Two companies, International Geomarine Corp. and Coal Conversion Corp. held, at different times, PRLAs covering more than 10 percent of all land under permit. (See table

Figure 58.—1980 Coal Leaseholdings by Business Activity Category (percent of total leased acreage)



SOURCE: Off Ice of Technology Assessment,

Figure 59.— 1980 PRLA Holdings by Business Activity Category (percent of total acres under permit)



SOURCE Off Ice of Technology Assessment

109.) They do not appear on the list of current PRLA holding groups because they have assigned all of their PRLAs to other parties.

The future disposition of PRLAs has several uncertainties. * The current Department of the Interior leasing policy calls for the processing of PRLAs in sequence between 1981 and 1984, but it is unclear how many will be converted to leases or what restrictions on development will be included among the terms of leases that are granted. It would thus be speculative to add lease and PRLA holdings into grand totals, and OTA has not done so. The following pages discuss briefly both types of holdings by each business activity category in order of decreasing size of holdings.**

Electric Utilities

Electric utilities currently hold more Federal coal land under lease than any other business category identified by OTA; they rank sixth in PRLA holdings. Seventeen utilities and one utility fuel acquisition association now control 21 percent of leased acreage and 9 percent of land under PRLAs. These companies mined 30 percent of all coal produced from leased land in fiscal year 1979, more Federal coal than mined by any other business activity category (see table 110). (Nationwide, all utility coal production accounted for 11 percent of the coal industry’s total production in 1979).

More than any other industry group examined in this survey, utilities have undergone complicated internal restructuring related to coal lease management. Several utilities now hold leases or PRLAs in the name of one or more subsidiaries, e.g., coal mining subsidiary, resource development subsidiary, landholding subsidiary, or legal entity without employees or business activities. Also,

Table 110.—Federal Leaseholdings and Production by Business Category

Business activity category	1970 leased acres	1972 coal production from Federal leases	1980 leased acres	Fiscal year 1979 coal production from Federal leases
Electric utilities	18% 132,038	47% 4.8	21% 163,259	30% 17.8
Energy companies	18% 132,274	5% 0.51	20% 155,024	16% 9.9
Metals and mining companies	12% 107,504	12% 1.2	2% 17,620	16% 9.3
Oil and gas companies (minor)	4% 26,911	2% 0.23	6% 45,926	9% 5.3
“Other” companies	6% 41,153	4% 0.46	10% 77,861	9% 5.2
Independent. coal companies	11% 78,297	20% 2.0	7% 55,410	7% 4.4
Natural gas pipeline companies	0% 0	0% 0	5% 36,317	4% 2.4
Peabody Coal Co.	8%[a] a	0%[a] a	8% 62,009	4% 2.2
Steel companies	6% 46,114	7% 0.77	8% 60,015	2% 1.3
Nonresource-related diversified companies	1% 10,015	0% 0	5% 35,675	2% 1.0
Unincorporated individuals	11% 78,995	3% 0.27	6% 43,215	1% 0.72
Kemmerer Coal Co.[b]	5% 33,793	0% 0	4% 32,191	below 1% 0.06
Total	94% 687,094	100% 10.3	99%0 784,522	100% 59.5

NOTE: Percentage sums might not equal totals because of rounding. All land holdings listed as acres. All production listed in million tons of coal.

a Peabody 1970 land holdings and 1972 productions totaled In metals and mining category.

b In March 1981, Kemmerer Coal Co, was purchased by Gulf Oil Corp.

SOURCE: Office of Technology Assessment.

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* see chs. 3, 6, 7, and 9 for more information about the status of PRLAs.

* *The only exception is the other category that is discussed at the end.

utilities have been active in several joint venture leasing and multicorporate development projects, One utility currently holds different leases in the name of five subsidiaries and is involved in three multicorporate lease development projects. The internal restructuring of utilities and their involvement in multicorporate leasing ventures appears to indicate a policy decision by some utility managements that coal leasing and mining activities should be separate from electrical generation activities because of the different management skills that these activities require. Furthermore, this division enables utilities, as a regulated industry, to clearly distinguish among totally regulated, partially regulated, and unregulated business activities.

Utilities made their most significant lease acquisition gains in the mid to late 1960's at the same time as the energy companies and the smaller oil and gas companies, but before the entry of the natural gas pipeline companies. Most utility-mined coal is used in powerplants owned by the leaseholding company (captive production), although increasing amounts of utility-mined coal are being sold on the open market. Utilities play a unique role in the coal industry as both an important producer of coal and the major consumer of coal. Utilities burned 77 percent of all domestically used coal in 1979.

Energy Companies

Energy companies in this survey include the 18 largest privately owned oil companies based on worldwide petroleum production. Eleven of these companies now own leases or PRLAs. They rank second in both categories, holding 20 percent of leased land and 16 percent of land under PRLAs. Energy companies produced 16 percent of the coal mined from leased land in fiscal year 1979.

The late 1960's marked the period of greatest growth in Federal coal landholdings by energy companies, well before the Arab oil embargo and the energy shortage conscious 1970's. Most of the leases obtained by these companies were acquired through lease assignments or by the purchase of a company that held leases among its assets. * Only 16 of 110 leases acquired by energy majors were obtained by de novo leasing directly from the Federal Government. Similarly, only 7 of 27 PRLAs now owned by energy majors were obtained de novo. Energy companies appear to be continuing to acquire land through assignment and corporate mergers. In 1980, three leaseholding companies were purchased by energy companies and several lease assignments to energy companies were made. (See also table 108.)

Peabody Coal Co.

Peabody Coal Co. owns leases covering more Federal coal land than any other company or individual. Its leases cover 8 percent of all land under lease. In addition, Peabody controls 17 PRLAs, all located in Wyoming. Peabody accounted for 4 percent of Federal coal production in fiscal year 1979.

Peabody operated as an independent coal company from its founding until 1968 when it was purchased by Kennecott Copper Corp. The acquisition was challenged by the Federal Trade Commission on anticompetition grounds and a divestiture order was issued in 1973. In 1977, Kennecott sold the company to the Peabody Holding Co., the ownership of which is shared by six companies with business interests as diverse as aerospace, mineral extraction, and life insurance. Because of its unique ownership structure and because of its large holdings, Peabody was treated in the OTA survey as a separate business activity after 1977.

Steel Companies

Steel companies were among the earliest participants in Federal coal leasing, owning 12 percent of all land under lease in 1950. The industry is still well represented (five companies control 8 percent of leased land) but its importance in Federal coal leaseholding has declined because of the entry of

*See chapter 3 for a discussion of methods used to acquire coal leases, many companies from other industries. Steel companies currently do not own any PRLAs.

Steel companies produced 2 percent of all Federal coal mined in fiscal year 1979. Most of this production was for captive use as a raw material for coke ovens at steel mills. Hence, the industry has focused its attention on leasing in the coal fields of Oklahoma, Colorado, and Utah that contain metallurgical grade coal.

Independent Coal Companies

In 1950, 18 independents constituted the largest leaseholding business group, controlling 35 percent of all land under lease. Today they control just 7 percent. Only one PRLA is held by an independent coal company. Historically, changes in ownership patterns by independents have occurred at a rapid pace. Over 60 independents have held leases, but none of the current 21 independent lessees was among the original 18 in 1950. Rising mining costs, the preference of utilities for large supply contracts from single producers, and a slow growth in local domestic or industrial coal use restrict the business opportunities of independent coal companies. As a result, many leaseholding independents have assigned their leases to principally noncoal companies or have been acquired as subsidiaries. At least 10 leaseholding companies that are now wholly owned coal mining subsidiaries once operated as independent coal producers.

In spite of these trends, independents remain the fifth largest leaseholding business category. Furthermore, several present lessees, notably Garland Coal and Mining Co. and North American Coal Corp., have built substantial coal reserve bases through the leasing program. Also, several other independents have entered the Western coal fields for the first time in the last decade. Independent coal companies accounted for 7 percent of Federal coal production in fiscal year 1979.

Oil and Gas Companies (Minor)

Eight oil and gas companies (those companies not large enough to appear among the energy majors and which do not operate large natural gas pipelines) now control about 6 percent of all land under lease and 8 percent of land under PRLAs. They rank sixth and seventh in total holdings respectively. Oil and gas companies entered coal leasing in the mid-1960's and their holdings have grown slowly but steadily ever since.

Lessees and PRLA owners in this category range from small oil wildcatters to large companies such as Kerr-McGee Corp. and Quaker State Oil Refining Corp. These companies accounted for about 9 percent of the total production of Federal coal in fiscal year 1979.

Unincorporated Individuals

The role of unincorporated individuals in the leasing program, at one time second only to the independent coal companies, has greatly declined in relative importance. On the other hand, although their holdings of PRLAs have also declined, individuals still have the largest share of land under PRLAs of any business category.

In 1950, unincorporated individuals constituted the second largest leaseholding group and held 27 percent of all acreage under lease. Their share of leased acreage has declined to 5 percent today. Many leases held by individuals include mines that have been closed for years and exhibit little potential for reopening. One percent of fiscal year 1979 Federal coal production occurred on leased land held by individuals.

In 1970, unincorporated individuals held 46 percent of all land included in PRLAs. Over the past decade, many of these PRLAs have been assigned to corporations and the share held by individuals has dropped to 20 percent. Although unincorporated individuals are still the major PRLA owners, the decline in the number of PRLAs held by individuals is likely to continue.

The decline of lease and PRLA holdings by individuals reflects a decreasing use of the "sole proprietorship" business organization by small mining firms in favor of some form of incorporated business structure. Another reason for this decline is the abolition of the preference right leasing program, a popular and low cost lease acquisition route for individuals, including land agents operating under contract to corporations and individual land speculators. Finally, the leasing moratorium of the 1970's, which increased the assignment value of existing leases and PRLAs, and the diligent development requirements defined in the 1976 coal leasing regulations may have been incentives for individuals to sell leases that they could not mine.

Natural Gas Pipeline Companies

Natural gas pipeline companies are the eighth largest leaseholding business group and the third largest group holding PRLAs. Six of these companies hold 5 percent of leased land and 12 percent of land under PRLAs. They mined 4 percent of all Federal coal produced in fiscal year 1979.

All leases and PRLAs now owned by natural gas pipeline companies have been acquired since 1971 during a period when opportunities to acquire leases de novo were limited. Twenty-five of 27 leases and 27 of 29 PRLAs were obtained by assignment or segregation from existing leases or PRLAs rather than directly from the Government,

Nonresource-Related Diversified Companies

The nonresource-related diversified business category includes companies with principal lines of business activity that are not energy or mineral related, but which complement or could be integrated with resource development. It includes, for example, several chemical companies, which might use coal as a chemical feedstock or might develop synfuel technologies, and companies such as General Electric and General Dynamics that sell electrical generation equipment.

The companies in this category are latecomers to Western leasing, Their leaseholdings have increased from 1 percent in 1965 to 5 percent in 1980. They form the ninth largest leaseholding category, In addition, such companies hold three PRLAs. They produced 2 percent of all Federal coal mined in fiscal year 1979, The most significant increase in holdings by companies in this category occurred in 1976 when General Electric purchased Utah International, which controlled nearly 25,000 acres of leased land. Utah International was an independent metals and mining company prior to its acquisition by General Electric.

Kemmerer Coal Co.

Kemmerer Coal Co, is one of the oldest Western coal producers, dating back to the late 19th century. Since 1926 Kemmerer has been owned by the Lincoln Corp., a holding company of Kemmerer family interests. * In September 1980, the family announced its intention to sell Kemmerer Coal. Its recent sale to Gulf Oil Corp. marks a major shift in lease and PRLA ownership.

Kemmerer now owns 4 percent of all land under lease and 10 percent of all land under PRLAs. Kemmerer produced less than 1 percent of Federal coal mined in fiscal year 1979. The company ranks as the 10th largest leaseholding category and the fourth largest holder of PRLAs,

Metals and Mining Companies

Metals and mining companies entered Western coal leasing early, Although recent corporate acquisitions have sharply reduced their leaseholdings, these companies continue to account for significant Federal coal production.

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* Kemmerer was studied separately by OTA rather than as an indepenedent coal company because of its ownership by Lincoln Corp., which includes noncoal business among its interests.

Metals and mining companies held 12 percent of all land under lease in 1950 and 15 percent in 1975. This total has dropped to 2 percent over the past 5 years, principally because of the divestiture of Peabody Coal by Kennecott Copper Corp. and the purchase of Utah International by General Electric. Both actions resulted in the removal of large acreages from the totals of the metals and mining category. In spite of these developments, metals and mining companies produced about 16 percent of all coal mined from Federal land in fiscal year 1979.

Amax, Inc., a company grouped in the metals and mining category, currently holds 9 percent of the land under PRLAs. These holdings alone rank fifth among the business categories studied by OTA. *

Landholding Companies

Independent land companies, like individual land agents, featured prominently in the early history of the leasing program. They acquired large blocks of coal bearing land for eventual resale to coal developers or other investors. Their role peaked in 1960 when they held 8 percent of all land under lease. In 1980, seven landholding companies owned leases covering less than 1 percent of the acreage under lease and PRLAs covering 1 percent of the land under PRLAs. They account for no Federal coal production.

The reasons for the liquidation of the holdings of most independent land companies are similar to those for individual land agents: the abolition of preference right leasing, the diligent production requirements, and the impact of the moratorium on the resale value of leases and PRLAs.

*Amax has been placed in the metals and mining category instead of being listed separately because of its identifiable business activity and because prior to 1980 other companies in this category held PRLAs.

"Other" Lessees

This last category includes lessees that do not fit into one of the business categories established during the survey and which, on their own, do not control more than 5 percent of the land under lease or permit. Such companies presently hold about 10 percent of all leased land and about 15 percent of all land under PRLAs. This other category includes lessees with an amazing diversity of interests. For example, it includes a railroad holding company, a heavy construction company, a cement company, two banks, three conglomerates, and a religious institution. About 9 percent of all coal produced on Federal land comes from leases held by lessees in the other category.

Federal Coal Production by Business Category

Ownership of leases covering Federal land is only one measure of involvement of companies and individuals in the leasing program. The amount of coal production from leased land is another measure. Based on limited information available for past Federal coal production on a lease-by-lease basis, OTA has compared acreage holdings of business activity categories in 1970 and 1980 with Federal coal production by these categories in 1972 and fiscal year 1979. (See table 110.)

During the 1970's the total number of acres leased by the 12 business categories* that now mine coal increased 14 percent from 687,094 acres to 784,522 acres. Between 1972 and 1979, on the other hand, total coal production summed over all these categories jumped nearly sixfold, from 10.3 million tons to 59.5 million tons. In terms of percentage of total production, the share of production con-

*In fiscal year 1979 no production was contributed by independent land companies.

tributed by utilities decreased from 47 to 30 percent and the share of independent coal companies dropped from 20 to 7 percent. In both cases, absolute production increased substantially, by nearly a factor of four for the utilities and by over a factor of two for the independent coal companies. During the same period, the shares of production of the energy companies increased from 5 to 16 percent. Production by natural gas companies, metals and mining companies, and oil and gas companies also increased sharply, Production by unincorporated individuals also rose nearly threefold, although declining from 3 to 1 percent of total Federal coal production.

Electric utilities, metals and mining companies, and oil and gas companies are all producing Federal coal at levels greater than their share of leased acres would suggest. The level of production of the metals and mining companies is particularly high relative to their share of leased acres. Present production by energy companies, Peabody and Kemmerer Coal, steel companies, nonresource-related diversified companies, and individuals is below the share suggested by their current acreage holdings. *

*Many currently nonproducing leases arc being activelv developed. See ch. 6.

The Business Organization of Coal Lease and PRLA Owners

OTA also examined the changes in the organizational structures of coal lease and PRLA owners, Four types of business organization structures were defined and analyzed. They are:

- Unincorporated individuals — persons, including sole proprietorships, partnerships, and estates.
- Independent corporations — companies not wholly owned by one or more other companies.
- Subsidiary corporations — companies wholly owned by a single other company.
- Multicorporate entities — companies wholly owned by two or more companies (such as joint ventures) or two or more companies holding shares in leases or PRLAs.

Table 111 and figure 60 trace the history of lease ownership by the four organization categories. They show that the relative importance of unincorporated individuals in leasing has been sharply reduced since the 1950’s. They reveal the dominant role of independent corporations in the 1950’s and 1960’s and their recent decline in relative importance. They show that the subsidiaries category has grown in importance over the years. Finally, they show that muIticorporate entities are the newest type of business organization to attain significance in Western leasing,

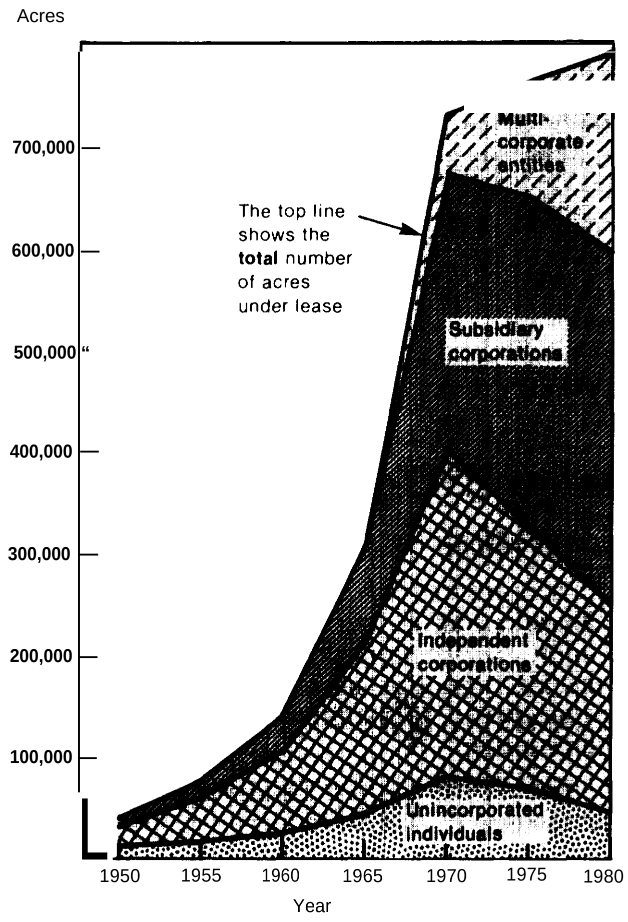
The role of the four business organizations as owners of PRLAs between 1970 and 1980

Table 111 .—Number of Acres Under Lease by Type of Business Organization 1950-1980 and Percent of Total Leased Land by Type of Business Organization

	Unincorporated indivduals	Independent corporations	Subsidiary corporations	Multi-corporate entities	Uncategorized companies
1950. ,	11,129 27%	18,504 45%	10,824 26%	0 %	1,035 2 %
1955. .	17,618 23%	40,495 53%	15,921 21%	0 %	1,915 3 %
1960. .	25,678 18%	79,717 55%	36,058 25%	0%	2,453 2%
1965. .	41,475 13%	169,402 55%	91,690 30%	640 <1 %	5,147 2 %
1970. .	78,995 11%	319,847 44%	271,329 37%	60,504 8 %	2,643 < 1 %
1975. .	66,515 9 %	257,637 34%	321,576 42%	112,418 15%	6,848 1 %
1980. .	43,215 5 %	204,612 26%	343,865 43%	197,491 25%	1,845 <1 %`

SOURCE. Off Ice of Technology Assessment

Figure 60.—Number of Federal Coal Acres Under Lease by Type of Business Organization, 1950-80



SOURCE Off Ice of Technology Assessment

Table 112.—Acres and Percent of Total Acres Under PRLAs Held by Business Organization Category

	1955 1960 & 1965	1970	1975	1980
Unincorporated individuals	160-5,890 100%	147,022 46%	115,317 28%	80,559 20%
Independent corporations	— —	107,558 33 %	89,345 22%	47,480 12%
Subsidiaries	— —	68,145 21 %	143,344 34%	177,783 44%
Multi-corporate entities	— —	— —	67,613 16%	95,002 24%
Unknown	— —	260 —	260 —	3,077 1%
Total	160-5,890 1 00%	322,725 100%	415,619 100%	403,800 100%

is summarized in table 112. The patterns and trends are very similar to those observed for leaseholders with exceptions that unincorporated individuals play a larger role among holders of PRLAs and independent corporations have a smaller share of PRLA land than leased land.

Unincorporated Individuals

The relative importance of individuals in the leasing program has declined significantly both in terms of leases and PRLAs. Unincorporated individuals control just 5 percent of all land under lease, down from 27 percent in 1950; they hold 20 percent of all land under PRLAs, down from 46 percent in 1970. Individuals today hold fewer leased acres than any of the four business organizations examined and rank third in PRLA holdings. Incorporation provides increased legal and financial protection over the sole proprietorship form of business. This advantage provides one of many reasons for the declining role of individuals. Other reasons were presented in the individuals "business activity category" earlier in this chapter.

Independent Corporations

From 1950 to 1970, independent corporations held the largest share of leased land of the four organizational categories. Since 1970, their role has declined and they now hold 26 percent of leased land and 12 percent of land under PRLAs. Independent corporations are the second largest leaseholding group and the smallest PRLA holding group among the four organizational categories.

Subsidiary Corporations

OTA has defined a subsidiary corporation as a company wholly owned by one other company. Subsidiary companies currently own more leases and PRLAs than the other three organizational groups. The leaseholdings of subsidiaries have grown steadily from 21 percent of all land under lease in 1955 to

43 percent in 1980, Their share of PRLAs increased from 21 percent in 1970 to 44 percent in 1980.

Subsidiaries have used four different methods to increase their lease and PRLA holdings, First, subsidiaries have acquired an increasing share of leases and permits issued de novo by the Government. Secondly, many leases and permits held by individuals or independent corporations have been obtained by subsidiary companies through assignment. Thirdly, some independent companies have undergone internal reorganization or formed new subsidiaries, resulting in the transfers of title to leases or PRLAs to a subsidiary within the corporation. Finally, dozens of independent corporations have been purchased by other companies thereby changing their status from independent to subsidiary companies. Title to leaseholdings was frequently retained by the formerly independent company rather being transferred to the purchasing company,

The present large holdings of subsidiaries is particularly prevalent in two business activity categories examined by OTA, coal mining and landholding,

In 1950, 18 independent coal companies comprised the largest leaseholding category while only three coal subsidiaries of noncoal parent companies held leases, By 1980, 36 wholly owned coal mining subsidiaries held 36 percent of land under lease, while the share held by independent coal companies had dropped to 7 percent, Similarly, only one PRLA is held by an independent coal company today, while 33 are owned by coal subsidiaries.

In many cases, there is a direct link between the decline of independent coal companies and the growth of subsidiaries, At least 10 of the wholly owned coal mining subsidiaries holding leases today previously operated as independent companies. A larger number of independent coal companies went out of business after selling their assets—including coal leases—to noncoal companies that subsequently organized coal mining subsidiaries to which the leases were assigned.

Landholding companies provide another example of the trend towards 1easing by subsidiary rather than independent companies. In 1960, 8 percent of all land under lease was controlled by independent landholding companies that hoped to profit from the eventual assignment of their leases to coal development companies. Today the independent landholding companies hold less than 1 percent of all land under lease. On the other hand, starting in the early 1960's, leaseholdings by landholding companies that are subsidiaries of companies with principal business activities other than coal mining has increased steadily. Today nine landholding subsidiaries control more acreage than the independents ever did. Similarly, only two PRLAs are owned by independent land companies while 30 are owned by land subsidiaries.

The two leasing trends among landholding companies appear to be unrelated. Most independent landholding companies acquired leases as speculators and they have gradually liquidated their holdings over the past decade. Many of the companies now holding leases—most notably the energy companies and utilities—have formed landholding subsidiaries to which leases have been assigned. These subsidiary landholding companies are legal entities through which large corporations hold land, usually for future development.

Multicorporate Entities

OTA has defined multicorporate entities as companies wholly owned by two or more companies (such as joint ventures) or two or more companies sharing ownership of leases.

Over the past decade there has been a substantial increase in lease and PRLA holdings by various types of multicorporate business organizations. They represent the newest form of business organization to gain a significant share of the Federal coal leasing program. Since 1970, leaseholdings by such entities have increased from 8 to 25 percent and

PRLA holdings have increased from zero to 24 percent. Multicorporate entities are now the third largest leaseholding business organization studied by OTA and the second largest PRLA holding group.

Three types of business arrangements are included in the multicorporate entity category. The first includes two or more corporations holding shares in leases or PRLAs. For example, 10 leases are held jointly by Consolidation Coal Co. and Kemmerer Coal Co. and 10 PRLAs are co-owned by Fannin Square Corp. and Eastern Associated Properties Corp. Secondly, this category includes companies that represent legal joint ventures of two or more companies formed to develop specific business interests. These include companies such as Colowyo Coal Co., a joint venture of W. R. Grace & Co. and Hanna Mining Co., and Cumberland Coal Co., a joint venture of subsidiaries of Peter Kiewit Sons and Union Pacific Corp. Finally, this category includes Peabody Coal Co., (which is owned by six companies through participation in the Peabody Holding Co.), and Ark Land Co. (which is owned by Ashland Oil and two Hunt business enterprises).

Implications of Lease and PRLA Ownership Patterns and Trends

The OTA analysis of the historical roles of different business activity and organizational structures in coal leasing suggests several observations.

Concentration

The data obtained in this study reveal little evidence of a concentration of lease or PRLA holdings among fewer companies. The number of participants in leasing nearly doubled from 1950 to 1980, from 84 to over 160. The four largest leaseholders in 1950 controlled 32 percent of all land under lease while the top eight controlled 34 percent in 1980. Hence the number of participants has increased and the concentration of ownership among the top companies has remained nearly unchanged. The number of PRLA holders has increased from 37 in 1970 to 47 in 1980.

Other evidence suggesting the absence of concentration is provided by the entry of lease and PRLA holders from an increasingly wide assortment of businesses. In 1950, only four business activity categories were identified in this survey as holding at least 5 percent of all land under lease. By 1980, nine such categories were identified. Also, while six business categories contributed 5 percent or more of the total production from Federal land in 1972, seven categories provided at least that level of output in fiscal year 1979. In both 1970 and 1980, six business activity categories held at least 5 percent of all acreage under PRLAs.

While the above data suggest that concentration has not occurred, other data show that leaseholding entities typically hold larger blocks of Federal coal land and more Federal coal leases than in earlier years. During the 30-year period when the number of leasing participants nearly doubled, the total number of acres under lease increased 18 fold and the number of leases increased sixfold. On the average, a lessee held 3.38 leases and 4,975 acres under lease in 1980, 10 times more than the 493 acres held, on the average, and three times the 1.04 leases held, on the average, by lessees in 1950. Little change is noted for average number of acres held by PRLA holders. For PRLAs, the average number of acres held was 8,722 in 1970 and 8,591 in 1980.

Diversification

The increased involvement in the Federal coal leasing program by widely different types of businesses is complemented by a trend toward increased diversification of business interests within the lease and PRLA holding companies. Three patterns within this trend are noteworthy.

First, there is a growing involvement in the leasing program of horizontally integrated companies. The energy companies, natural gas pipeline companies, and smaller oil and gas companies together hold 31 percent of the land under lease, In 1965, the companies in these three categories combined held only 4 percent of Federal coal acreage under lease. These companies also control 36 percent of all land under PRLAs, up from 15 percent in 1970. For these companies, involvement in coal leasing appears to be part of a strategy to branch into several energy resource fields.

Growing involvement of companies for which coal reserves acquisition represents a vertical integration of business activities is a second trend in lease ownership patterns. Steel companies and electric utilities—which together hold 29 percent of all land under lease today—are the two principal examples of leasing by vertically integrated companies. Steel companies have for decades mined significant quantities of coal and have participated in the leasing program since its inception. The growth of utility involvement in Western leasing since 1965 to its position as the largest leaseholding business activity category in 1980 represents a new and significant type of vertical integration among lessees. The Federal coal leasing program has provided an important avenue for utility entry into the coal industry. Utilities provided 11 percent of the Nation's coal output in 1979. They hold 21 percent of all Federal coal land under lease and produced 30 percent of all coal mined on Federal land. Approximately one-fourth of all utility "captive" coal production was mined from leased Federal reserves.

A third trend reflects the growing involvement of large, already diversified companies in coal leasing. These include metals and mining companies that are diversifying their mineral extraction skills to include coal. They also include chemical and high-technology companies for which entry into the coal industry represents a diversification related to, but not integrated with, existing business activities.

The shift in leaseholdings to large, diversified and integrated companies in turn suggests several observations. First, lease development decisions are increasingly shaped by priorities that reflect business opportunities and capital availability unrelated to coal development. Secondly, these ownership changes can cause a relocation of final decisionmaking authority affecting coal development from local managers to those sometimes working hundreds or thousands of miles from lease sites. Thirdly, the internal business arrangements established by large companies to manage coal leases result in complex decisionmaking processes. While all three of these trends might contribute to increased efficiency in the coal industry, they make understanding coal industry priorities an increasingly difficult task.

Another result of ownership changes is the appearance of more lessees with the financial resources available for coal development that far exceed the resources available to the earlier, smaller coal leasing companies. Increasing participation by larger and more complex corporate entities is not surprising considering the large capital requirements posed by today's coal development.

Next, the increasing tendencies of the large, diversified companies holding leases to establish multicorporate development projects could raise competition concerns not posed when leasing was dominated by many small independent companies. Multicorporate lease development ventures provide a means for corporations to distribute the risks involved in undertaking large-scale coal development projects. They also increase the capital generating capacity of the project as a whole. At the same time, they increase the level of intercorporate information exchange and communication. Finally, joint venturing through subsidiaries far removed structurally from the parent organization has recently provided indirect entry into coal leaseholding by railroads. * (Railroads are prohibited by the Mineral Leasing Act of 1920 from direct lease ownership.**)

Leasing Policies

Several recent studies have pointed to the potential importance of Federal coal leasing policies as a determining factor in the organization and development of the coal industry over the next several decades. The Harvard Business Study, Energy Future, for example, observes that: "competition can be protected by methods short of horizontal divestiture, such as existing antitrust laws, setting limits on the share of reserves any single firm can control, and innovative leasing policies. The last can be especially effective."***

The present study shows that over the past 30 years, ownership patterns on leased public coal land have generally been similar to the pattern of industry restructuring typical for private land. Indeed, some developments on Federal coal leases—such as the growing role of utilities as "captive" coal producers—seem to be leading indicators of the changing character of the American coal industry.

*See ch. II, sec. 6 M, Other Leaseholders, of the OTA Technical Memorandum for further in formation. See reference on p. 371.

**A recent Justice Department report recommends striking from Federal law prohibitions against the issuance of Federal coal leases to railroads or their affiliates. (Competition in *the Coal* Industry. *Report of the* U.S. *Department* of *Justice, pursuant to section 8 of the Federal Coal* Leasing *Amendments Act of 1976* for *Fiscal Year 1979*: U.S. Departmen t of Justice Antitrust Division; November 1980.)

* * *R. Stobaugh and D. Yergin (cd.), Energy Future: Report of the Energy Project of the Harvard Business School (New York: Random House, 1979).

Appendixes

APPENDIX A

Development and Production of Federal Coal Leases in the Southern Rocky Mountain States

Colorado

Overview

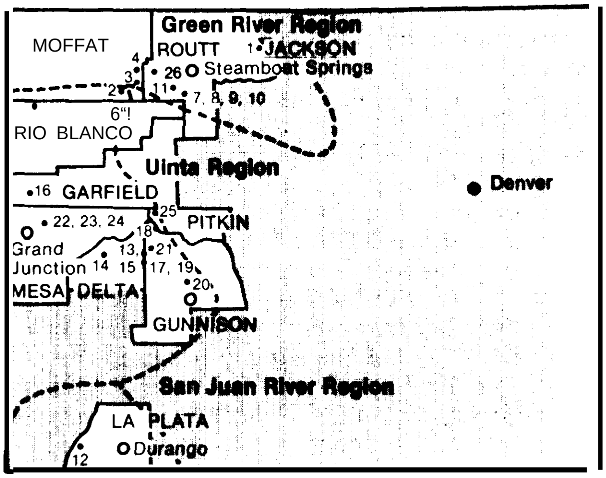
Colorado has Federal leases in four coal regions: the Green River, the Uinta, the San Juan, and the Denver Raton Mesa regions, (See table 34 in ch, 6 for a summary of acreage and reserves under lease.) The San Juan and the Denver-Raton Mesa regions contain the fewest number of Federal leases. There is one Federal lease in an approved mine plan in the San Juan region. Six Federal leases in the Denver-Raton Mesa region are currently undeveloped. Most of Colorado's 127 Federal leases and reserves are located within the Uinta and Green River regions. In the Green River region, 31 leases are in approved mine plans, 3 are in pending mine plans, and 23 are not in mine plans. In the Uinta region, 22 leases are in approved mine plans, 18 are in pending mine plans, and 23 are not in mine plans. (See fig. A-l.)

In total, Colorado's 127 Federal coal leases cover more than 126,000 acres of land and contain over 2.2 billion tons of recoverable coal reserves. The State thus ranks second to Utah, and before New Mexico in lease acreage and reserves in the Southern Rocky Mountain region. In 1979, Colorado mines with Federal leases produced almost 16 million tons of coal, as compared to roughly 10 million tons from Federal mines in Utah, and about 8 million tons from New Mexico Federal mines.

Overall the maximum production capacity for Colorado's existing and proposed Federal mines is almost 45 million tons per year. production from these mines in 1986 could exceed 29 million tons. Production from undeveloped leases in 1986 is only 0.6 million tons, By 1991, production from existing and proposed Federal mines could increase to about 35 million tons, and production from currently undeveloped leases could also increase substantially, to about 8 million tons,

The Department of Energy (DOE) 1985 production goals for Colorado of 34 million to 38 million tons are higher than OTA's estimate of potential production from Federal mines in 1986 (29.4 million tons), The difference in large part will probably be offset by production from non-Federal mines and from mines on Federal preference right lease applications (PRLAs), The OTA Colorado task force estimated that 1986 minimum State production would be about 26 million tons from all mines. By 1991, the Colorado task force projected that minimum State production would range from

Figure A-1 .—Coal Mines on Federal Lands in Colorado



Map locations

1- Canadian Strip
2- Colowyo
3- Eagle Nos. 5, 9
4- Trapper
5- Deserado
6- Meeker Area
7- Apex No. 2
8- Edna
8- Trout Creek
9- Energy Fuels Nos. 1, 2
10- Johnnies
11- Seneca, 2W
12- National King Coal
13- Orchard Valley
14- Red Canyon No. 2
15- Somerset
15- Blue Ribbon
16- Loma Complex
17- Bear
17- Mt. Gunnison
18- Coal Basin
19- Hawksnest East & West
20- Ohio Creek No. 2
21- Windjammer No. 1
22- Cameo Nos. 1, 2
22- Roadside
23- Coal Canyon
24- Cottonwood Creek
25- Snowmass
26- Marr

SOURCE: Office of Technology Assessment.

32 million to 38 million tons. OTA's analysis found that potential production from mines with Federal leases could reach 43 million tons in 1991 exceeding the task force projection and almost equaling the DOE high-level **1990** production goal of 43.3 million tons. (The DOE low-level goal is 28 million tons and the midlevel goal is 35 million tons,) By the 1990's Federal mines are expected to contribute a larger share of total State production.

Green River Region

Of the four coal regions in Colorado, the Green River region is the most important in terms of its total coal reserves, its total mine capacity, and its past and anticipated coal production. Roughly 60 percent of the region's total Federal lease reserves are not yet included in any mining plans. Only 2.5 percent of the region's lease reserves are contained within mine plans pending with the Office of Surface Mining IOSM), The remaining 38 percent of the reserves are included within approved mining plans. (Additional Federal production could come from the first new lease sales under the Federal coal management program which were held in the Green River-Hams Fork region of Colorado and Wyoming. Almost 56 million tons were leased in the January 1981 sale, and an additional 64 million tons were sold in April 1981).

Approved Mine Plans.—There are 10 mine plans involving 31 Federal leases that have been approved in the Green River region. Of these, 8 were actively in production in 1979 and produced a total of 11.2 million tons of coal in that year. Two mines were not producing in 1979, Six mines are surface operations and accounted for 93 percent of the production in 1979. All of the approved mines in this region are expected to be in production in 1986; moreover, all are expected to meet Department of the Interior's (DOI) diligent development requirements by that year. Total operating capacity for these mines is estimated at 23.6 million tons per year, of which 21 percent is underground capacity. According to mine plan projections, production for 1986 will reach about 19 million tons and could increase slightly to almost 20 million tons per year by 1991. These production levels represent 83 and 88 percent of maximum design capacity for existing mines. The total capacity of currently approved mines will decline slightly as 2 mines exhaust their existing lease reserves, several other large surface mines in the region will exhaust their strippable reserves in the 1990's and plan to shift eventually to underground operations to maintain production.

Most of the currently operating Federal mines in the Green River region are large operations with annual capacities ranging from 1.1 million to 4,8 million tons per year. The five largest mines account for 80 percent of the operating capacity; the mine with the greatest planned capacity is an underground mine, the multilease Meeker Area Mine, operated by Northern Minerals. This operation, which produced less than 0.1 million tons in 1979, is projected to be in full production by 1991, and will be a four-mine complex with a capacity of 4.8 million tons per year.

Of the approved, operating mines in the Green River region, the two with the greatest current production are surface mines. These are the Trapper Mine, operated by Utah International, Inc., and the Energy Nos. l&2 Mines, operated by Energy Fuels Corp. Both of these mines, with 1979 production of 2.3 million and 3.4 million tons, respectively, are producing at roughly 85 percent of their maximum capacity.

Pending Mine Plans.—There are three mine plans with a total of four Federal leases in the Green River region that are currently pending approval, Two mines, Western Fuel's Deserado Mine, and Gulf Oil's Trout Creek Mine, are expected to produce a total of 1.3 million tons in 1986. The Trout Creek Mine is a separate underground mine proposed to operate on a Federal lease that is also included in Gulf Oil's existing Edna Strip Mine. This mine is expected to be operating at its maximum capacity of 0,5 million tons per year in both 1986 and 1991. The Deserado Mine in the Lower White River Field will supply the Moon Lake Electric Co. 's new powerplant in Bonanza, Utah. production from proposed mines in this region is expected to increase from the 1986 level as a result of increased production from the Deserado Mine. Total projected production from pending mine plans in this region is 1.8 million tons per year in 1991. One proposed small mine on a post-FCLAA lease will probably not go into production because of financial difficulties caused by the delay in issuing the lease.

Undeveloped Leases.—The Green River region has the greatest amount of undeveloped reserves and the highest estimated future production from its undeveloped leases of any region in Colorado. The region has 23 undeveloped leases which contain approximately 816 million tons of coal within about 24,400 Federal lease acres. These leases are relatively large, both in acreage and in reserves, For example, 10 of the leases are greater than 1,000 acres in size and contain from 20 million to 250 million tons of recoverable coal reserves each.

Of the **23** undeveloped leases in the Green River region, 16 leases in 14 blocks with 792 million tons of recoverable reserves are promising new mine properties. The remaining 7 leases with less than 24 million tons of reserves could not support independent viable mining operations, (See table 44 in ch. 6.) Two leases have favorable development prospects. Seven have unfavorable development prospects; most of these leases with poor development potential have insufficient reserves to support an economically viable mine of minimal size. Based on OTA's evaluation, the majority of the reserves, 738 million tons contained within 14 leases, have uncertain development prospects,

The two leases in this region which have favorable development prospects are held by Peabody Coal Co, One lease is located midway between Peabody's existing Seneca and Seneca 2W operations, and is expected to be surface mined at a rate of about 0.6 million tons by 1986. This is the only undeveloped lease block that is projected to be in production in that year. It will supply the nearby Hayden powerplant under a dedication agreement, and will maintain Peabody's current capacity and production levels, Production from the other favorable lease, which will be an underground mine, is projected to begin in 1987 and will share existing nearby facilities. Maximum production capacity for this mine would be 1.0 million tons per year.

By 1991, 5 of the 14 leases with uncertain development potential ratings, are projected to be in production, Total production from undeveloped leases in the Green River region is estimated to be 6.4 million tons in 1991. Production will be concentrated in the Yampa, Danforth Hills, and North Park coalfields. Actual production may vary from these estimates. Current production from the Green River region goes primarily to utilities.

One of the small leases with anticipated production for 1991, held by AMCA Coal Leasing, was previously mined by underground methods, However, it also contains strippable reserves of bituminous rank which could be developed as a small mine to serve spot market or local needs. It is located in an active mining area where strip reserves are gradually being mined out, thus making its marginal strip reserves more desirable, production is estimated to be as much as 50,000 tons per year by 1991.

The 1991 production from the lease held by W. R, Grace & Co. could be as high as 1.4 million tons per year. Considerable uncertainty surrounds this projected production since one possibility for the lease's development is linked to Grace's proposed synthetic fuels plant in Moffat County. Recently, their initial coal conversion goals were scaled down from 5,000 to 500 tons per day. If the smaller plant proves to be successful, Grace could scale up to its original size. Grace could also develop this tract as an alternative source of coal for more conventional uses when strippable coal reserves in northwestern Colorado are expected to be depleted in the 1990's.

There are seven large Federal leases in the Danforth Hills Field of the Green River region: six are held by Consolidation Coal Co., and one is held by Utah International, Inc. Production from these leases is contingent on resolution of uncertainties involving the issuance of associated PRLAs and negotiations with surface owners, including a potential competitor, W. R. Grace & Co, Production from Consolidation Coal's lease blocks could reach 1.3 million tons per year by 1991 with an eventual capacity between 3 million and 6 million tons per year, The lease held by Utah International, although reported to have sufficient reserves to sustain an average-sized new mine, would probably only be developed if the lessee obtained sufficient additional acreage and reserves from its PRLA or new lease sales to allow operation of a very large surface mine similar to the adjacent Colowyo Mine, If development proceeds smoothly, OTA estimates that product ion from this mine could reach 1,3 million tons by 1991 out of a potential annual capacity of 3 million to 6 million tons,

The remaining coalfield in the Green River region that may have production by 1991 is the North Park Field in Jackson County. Possible production of 0.5 million tons per year from leases shared by Kemmerer and Consolidation Coal companies is estimated for 1991, however development is contingent on improvements in coal transportation from the area, No production is projected for 13 remaining undeveloped leases in the Green River region.

Uinta Region

The Uinta region contains **63** leases covering nearly *70,000* acres with a total of over *800* million tons of recoverable reserves, Approximately **203** million tons of reserves are contained in 22 leases in approved mine plans, about **427** million tons are in 18 leases with pending mine plans, and 173 million tons of reserves are in *23* leases without mine plans. Total maximum capacity is **8** million tons per year for approved mine plans and over 11 million tons per year for Federal leases in pending plans. potential capacity for leases without plans is estimated at 1.5 million tons.

As displayed in table 37 in ch. 6, projected production for 1991 is 7.4 million tons per year for pending plans, 5.8 million tons per year for approved plans, and up to 1.3 million tons per year for leases without plans.

Approved Mine Plans.—In the Uinta region there are eight operating mines which include 22 Federal leases. All but one of these mines began producing in the late 1970's and all of them reported production for 1979. Furthermore, past and anticipated future rates of production indicate that all of the mines will satisfy DOI's diligent development requirements by 1986.

Federal lease reserves total 203 million tons in approved mine plans. Total mine plan reserves are 208 million tons. All of the reserves are high volatile bituminous and all are best suited for recovery by underground mining methods. Several mines in the region produce high-grade metallurgical coal.

Total maximum design capacity of these mines is almost 8 million tons per year. The maximum capacity of individual mines varies widely—from 0.1 million tons per year for the small Ohio Creek No. 2 Mine to 1.4 million tons per year for Western Slope Carbon's Hawksnest complex. Western Slope's 1979 production was only 31 percent of their design capacity. However, they expect to be operating at full capacity by 1991, The Coal Basin Mine's multilease operation held by Mid Continent Resources, represents another large increment of capacity for approved mine plans. Their underground operation is designed to handle 1.3 million tons per year, and their projected production for both 1986 and 1991 of 0.9 million tons is expected to account for about 65 percent of this capacity,

Two mines, the Bear Mine, operated under a sublease from ARCO, and the Roadside Mine, operated by Cambridge Mining, are expected to exhaust their reserves by the end of this decade. The Bear Mine is currently operating at close to its capacity of 0.26 million tons per year and will shut down in the next few years before operations begin on ARCO's larger, Mt. Gunnison mine on the same lease. The Roadside Mine, which began producing in the 1900's and which has a capacity of 1.2 million tons per year, is reducing its operations and anticipates production of only about 0.3 million tons by 1986.

The Orchard Valley Mine operated by Colorado Westmoreland will exhaust its current lease reserves by the mid-1980's at its present production rate. The mine is expected to continue operations with the acquisition of new Federal lease reserves.

Pending Mine Plans.—The Uinta region has 18 Federal leases in 8 currently pending mine plans. In total, there are about 427 million tons of recoverable reserves on over 34,700 lease acres. One of these proposed mines, the Loma complex of Sheridan Enterprises, reported production for 1979. This was the result of development work at the mine site.

By 1986 five new mines are projected to produce approximately 2.8 million tons of coal. At this rate of production, three of these mines, the Blue Ribbon, Loma complex, and Windjammer mines, seem likely to meet DOI's development requirements by 1986. All eight of the proposed mines are expected to be in production by 1991, and all but one seems likely to meet diligence development requirements by then.

When all mines are brought into production, maximum operating capacity is expected to exceed 11 million tons per year. Given this capacity base, anticipated 1986 production of 2.8 million tons will represent approximately 25 percent of total mine capacity, and projected production of 7.4 million tons for 1991 will represent 67 percent of full capacity. several of the newer mines will probably not achieve full capacity until after l990.

Operating capacity for individual mines ranges from 0,12 million to 5.0 million tons per year. Two mines—the Loma project, operated by Sheridan Enterprises, and the Mt. Gunnison Mine, operated by ARCO—account for 70 percent of the total capacity for pending mine plans in the Uinta region.

When completed, the Loma project is expected to be producing from six underground mines using both longwall and room-and-pillar methods. Estimated production for 1991 is expected to be about 56 percent of the 5.0 million tons per year eventual planned capacity for the Loma Mines.

The Mt. Gunnison Mine is projected to begin production in 1983, and to take approximately 10 years to reach the estimated operating capacity of 2.8 million tons per year. The coal will be recovered by room and pillar underground mining methods, The reserves in the Mt. Gunnison leases are very large. If all seams in the lease, including seams not currently mined, are made part of the logical mining unit (LMU) reserves for diligence, Mt. Gunnison might have some difficulty in meeting the 2,5 percent production required for diligence.

Undeveloped Leases.—The Uinta region has a total of 173 million tons of recoverable reserves contained within 23 undeveloped leases. The majority of these reserves are recoverable by underground mining only, and their quality ranges from subbituminous to bituminous. Based on OTA's review of these leases, 18 leases in 6 blocks covering about 17,660 acres and containing approximately 159 million tons of reserves could sustain new mining operations. The remaining five leases, containing about 14 million tons of recoverable reserves do not have sufficient good quality reserves to support viable new mines.

Not all of the 18 viable leases, are likely to be developed. Eight leases were classified as favorable development prospects, three leases have uncerthin development prospects, and the remaining seven leases have unfavorable development potential.

None of the Uinta region undeveloped leases are expected to be in production by 1986. For 1991, OTA projects that two lease blocks held by U.S. Steel with a total of nine leases could be producing up to 1.3 million tons. Of this production, up to 0.75 million tons of high-quality metallurgical coal could be produced from eight U.S. Steel leases in the Coal Basin Field. There is some uncertainty about this production, however, due in part to the lease area's steeply dipping seams, faulting, and deeply buried seams which will make underground mining difficult and the fact that U.S. Steel has been purchasing production from the neighboring Coal Basin Mine. U.S. Steel has no current plans to develop the Coal Basin leases before 19$10. Two other mining companies have developed or planned development of adjoining mine properties which have similar property characteristics, indicating that the adverse mining conditions can be overcome. The remaining uncertainty concerns the currently depressed market for metallurgical coal. Three other lease blocks held by U.S. Steel in the Somerset-Paonia area have uncertain development prospects based on the expectation that they would be developed as part of a company strategy to expand coal operations to steam coal, since the coal on these blocks is not of metallurgical quality. U.S. Steel has an existing mine in Somerset that supplies its Geneva, Utah steel plants. The OTA Colorado task force estimated that, by making use of their existing loading and other facilities, surface mining production from the other leases could reach 0.5 million tons per year by 1991, Alternatively, the leases might be assigned to an independent operator.

No production is anticipated from the remaining 14 leases in the Uinta region including two blocks with a total of 7 leases held by Kemmerer Coal Co. in the Tongue Mesa Field. These leases have sufficient high-quality reserves to support a new mine, but there is not an adequate coal transportation system in place.

Denver-Raton Mesa Region

Currently there are no active Federal mines or any pending mine plans for Federal leases in the Denver-Raton Mesa region of southeastern Colorado. The region contains six Federal leases without mine plans, which OTA has organized into four lease blocks. Based on a review of the quality of leased coal, the size of the reserve base and the lessee's development capabilities, four of the leases in two blocks are considered to be viable mining properties. Peabody Coal Co. holds the four favorable lease properties which contain a total of over 48 million tons of surface recoverable reserves,

These leases have uncertain development prospects largely because the coal is lignite. Development of these tracts will likely require a near site use, such as a mine-mouth powerplant or synfuels facility, in order to overcome the less favorable economics of transporting the lower quality coal. The four leases could be producing up to 0.5 million tons in 1991, and thus may satisfy the DOI's diligent development requirements by that year, although this is still speculative. The other two leases in the region have unfavorable development potential. The lease held by CF&I Co., has unfavorable development prospects for 1991 because the lessee has available more attractive non-Federal reserves than those contained within this single lease block composed of small scattered parcels of Federal coal.

The remaining lease, a 40-acre tract with underground reserves, is not considered a viable mining property due primarily to its small reserves base.

San Juan River Region

The San Juan River coal region is located in Colorado and New Mexico; the larger portion of the region lies in New Mexico. There are six active non-Federal mines operating in the Colorado portion. The only Federal lease in the region is in the National King Coal Mine, a small operation producing about 70,000 tons per year for sale to local consumers. Coal was first produced from the lease in 1936 and production is expected to decrease from 83,000 tons in 1979 to 65,000 tons per year by 1986. The Federal lease reserves are expected to be mined out by 1991.

Summary of Production Potential

In 1979, the 19 mines with Federal leases produced over 16 million tons of coal with about half of this production (7.7 million tons) from Federal reserves. By 1986, two of the currently operating mines are expected to deplete their reserves, however, nine new Federal mines are expected to be in production. Overall, OTA projects that, total production from Federal mines will increase to nearly 30 million tons—almost double the 1979 production. The percentage of total production from Federal reserves is also expected to increase. By 1991, 35 mines containing Federal leases are projected to produce 43.1 million tons of coal, About 8 million tons of this production could come from currently undeveloped leases.

New Mexico

Overview

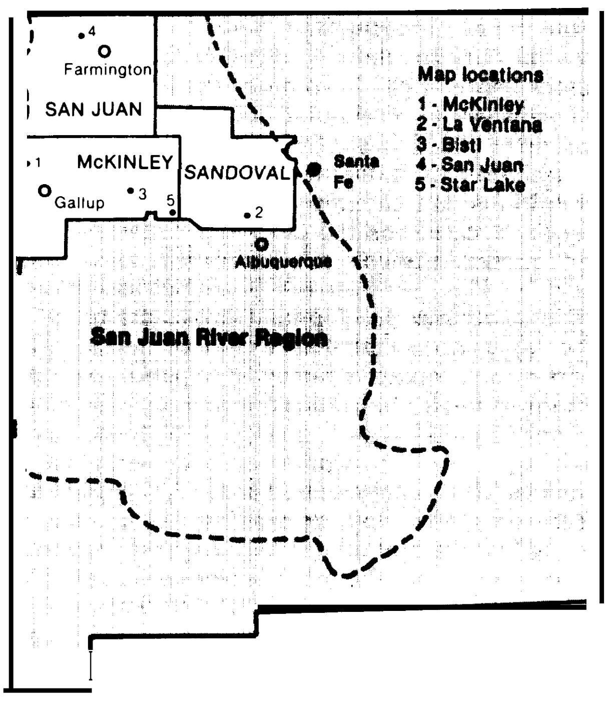
The 29 Federal coal leases in New Mexico cover over 44,000 acres and contain 447 million tons of recoverable coal. The State has the fewest leases and leased reserves among the three Southern Rockies States and fewer leased reserves than any major coal-producing Western State except North Dakota. Three of the leases are in the Raton Mesa region of northeast New Mexico and the other 26 are found in the San Juan basin in the northeastern part of the State.

Only one large coal mine complex is operating in the Raton Mesa region, It is located entirely on non-Federal land, No extensive development is expected to occur in this region on either Federal or non-Federal land, although an additional mine could be developed in the region. Coal is found in small scattered deposits throughout the rough and mountainous terrain of this region. Though the Raton Mesa contains high-quality and metallurgical-grade coals with a Btu content averaging 14,340 Btu/lb and sulfur levels averaging less than one percent, the difficult terrain, small reserves, and lack of markets has inhibited development. Other problems facing developers of three small leases here include limited local rail capacity (although the region itself is served by a main line of the Santa Fe Railroad), and complicated coal land access problems involving intermingled Federal, railroad, Spanish land grant, and private land blocks.

The San Juan basin contains 96 percent of the remaining coal resources in New Mexico, including nearly all of the strippable reserves, A substantial portion of the basin's reserves are controlled by the Navaho Tribe. Over 80 percent of the 1980 coal production of 16.5 million tons in the State came from this region and by 1990 it could account for over 95 percent. Typical San Juan coal has a Btu content of 10,492 Btu/lb and a sulfur content of 0.84 percent. It has relatively high average ash levels of 13.8 percent, although the ash content can be as high as 25 percent in some areas.

Mining currently occurs in two areas within the San Juan basin, There is at present little or no production in the central part of the basin (see fig. A-2). Production from the northwest corner, including the San Juan Mine on Federal land, is used at mine-mouth generating stations. Production from the McKinley Mine on Federal and Indian land in the southwest part of the region is shipped by rail mostly to Arizona and other Western markets. Most of the San Juan basin coal reserves, including areas with leased Federal coal, are not served presently by rail transportation. This central region of the basin is one of the largest untapped strippable coal deposits in the Western United States. The Santa Fe Railroad has proposed to build a 114-mile line into the area,

Figure A-2.—Coal Mines on Federal Lands in New Mexico



SOURCE: Office of Technology Assessment.

called the Star Lake Railroad. The final environmental impact statement has been issued. The remaining uncertainty involves 3 miles of right-of-way that cross land owned by Indian allotment holders. Rugged terrain makes rerouting across other land prohibitively expensive. Negotiations with the Indian allottees are underway and the railroad has asked the Secretary of Interior to waive the landowner consent requirement. The Bureau of Land Management had deferred granting of the rights-of-way across Federal land until resolution of the allottee issue, though it has approved use of Federal land for the project. The Star Lake-Bisti Regional Coal Environmental Statement projected that coal production associated with the railroad could eventually reach 75 million tons per year, About 8 million tons of Federal mine production in 1991 is tied to development of the Star Lake Railroad,

The 29 New Mexico Federal coal leases can be divided into 16 lease blocks. Three of these units are single leases in the Raton Mesa. The other 13 are located in the San Juan region.

Nine leases in two lease blocks are currently part of operating mines. These two mines produced 9.7 million tons of coal in 1980, about half of the State's total production with about 6.3 million tons produced from Federal reserves. Three lease blocks including nine leases are part of proposed mine plans which are now pending before DOI. The remaining 11 leases and 10 lease blocks are undeveloped and no mine plans to develop them had been submitted to DOI as of September 30, 1980.

Approved Mine plans.—The two producing mines which include Federal coal leases are the McKinley and San Juan Mines. The McKinley Mine includes four Federal leases owned by Gulf Oil Corp. and Indian and private lands. The San Juan Mine includes five leases owned by Western Coal Co., a joint venture of Public Service Co. of New Mexico and Tuscon Electric Co. It is operating almost entirely on Federal lands, although possible expansion onto coal lands on the Ute Mountain Indian Reservation to the north is being considered. Both are surface mines. The approved mine plans for these projects call for small increases in mining on Federal land over the next decade. The McKinley Mine is scheduled to increase production from 4.6 million to 5.0 million tons by 1991 and the San Juan Mine is scheduled to increase from 5.1 million to 5,5 million tons. The San Juan Mine will shift a portion of its capacity to underground operations on a new Federal lease acquired in 1980.

Pending Mine Plans.—Like the operating mines, the three lease blocks for which mine plans are pending are located in the San Juan region. Five leases are part of the La Ventana Mine project proposed by the lessee, Ideal Basic Industries. It is the only active or proposed mine on Federal leases in New Mexico that will be solely an underground operation. At least seven inactive leases in the La Ventana area once supported small underground mines, but these were closed due to structural and fire hazards, inability to comply with health and safety regulations, and the decline of the domestic coal market in New Mexico, The proposed La Ventana Mine plan has been designed to resolve what had been difficult safety problems involving poor roof conditions and the tendency of La Ventana coals for spontaneous combustion, A market for at least part of the coal produced exists at Ideal's cement plant in Albuquerque, The mine is scheduled to produce 1.1 million tons by 1986 and 1.5 million tons by 1991; it has an eventual capacity of 3 million tons per year.

The other two pending mine plans with four Federal leases are located in the area of the San Juan basin presently without rail service. Development of these tracts will depend on either the construction of the Star Lake Railroad or the construction of mine mouth power or synfuels plants, The proposed Bisti Mine includes three leases owned by Western Coal Co. Public Service Co. of New Mexico has proposed building a mine-mouth powerplant near this mine, but that project is in only preliminary planning stages and the construction schedule is still uncertain. The second lease block is a single lease owned by Peabody Coal Co., and Thermal Energy Co. The mine proposed for this site, however, is being developed by Chaco Energy Co., a subsidiary of Texas Utilities, Inc. The Star Lake Mine, as it is called, will likely supply powerplants owned by the parent company or serve other utility markets. The Star Lake Mine eventually will include reserves from pending PRLAs. The Bisti Mine is scheduled to produce 2.5 million tons by 1986 and 3 million tons by 1991. The Star Lake Mine is scheduled to produce 3 million tons in 1986 and between 3 million and 6 million tons by 1991. Coal from Star Lake would be shipped via the Star Lake Railroad.

Undeveloped Leases.—Eleven leases in ten lease blocks are inactive and have no mine plans for their development pending before DOI, although some planning work is underway on several of these. The three small leases in the Raton Mesa region fall into this category of undeveloped leases, The group also includes six small leases and two large leases in the San Juan region. These two large leases are part of proposed mining projects which have not yet reached the completed mine plan stage. Production from these mines is likely before the end of the decade, Some preliminary investigations of mine development on several of the smaller leases as part of mine development on adjacent lands has been reported, however, prospects for production before 1991 are unfavorable.

The two leases that might be in production by 1991 include 98 percent of all the undeveloped Federal lease reserves in New Mexico. The first lease is owned by Cimmaron Coal Co. and is part of the proposed LaPlata surface mine in northwest New Mexico. The mine could serve the supply needs of the nearby San Juan powerplant as reserves from the San Juan Mine are mined out. Based on a review of a wide range of factors, including coal quantity and quality, transportation access, environmental issues, engineering problems, and markets among others, OTA found that the lease has a favorable development potential. Production is scheduled to total 0.2 million tons in 1986 and between 1 million and 2 million tons in 1991.

The second large New Mexico lease (1,910 acres) is located along the route of the Star Lake Railroad. It is owned jointly by Fannin Square Corp. (a subsidiary of Texas Eastern Transmission Corp.) and Eastern Associated Properties Corp. (a subsidiary of Eastern Gas and Fuel Associates). The lease also received a favorable development prospect rating by OTA though several uncertainties cloud its future. The lessees are likely to need additional coal reserves adjoining the lease in order to create an economical mining unit for large-scale operations. The companies hold PRLAs for much of this land which might be converted to lease shortly. Texas Eastern Transmission received a DOE grant in 1980 to study the feasibility of building a major synfuels complex near the lease and supplied with coal from it. Prospects for building such a plant are uncertain, Any export use of the coal on this lease will be dependent on the completion of the Star Lake Railroad. The companies nevertheless are proceeding with plans for the Black Lake Mine, which if it proceeds, is likely to produce between 0.7 million and 6 million tons by 1991 depending on the companies' coal needs and the rate of development of adjoining reserves.

Of the nine small leases in eight lease blocks that are not likely to be in production before 1991, four blocks received uncertain development prospect ratings by OTA and four were rated as unfavorable for development.

Two of the leases with uncertain development ratings are located in the Raton Mesa region. The lessees of both are studying mining projects that include the leases, but small reserves, mining and transportation problems caused by the rough terrain earned these leases an uncertain rating at best. The other two lease blocks receiving uncertain ratings adjoin the proposed La Ventana Mine site, Each of these lease tracts once were underground mines, but they were closed because fires and explosions made them unsafe and uneconomical to mine. If Ideal Basic Industries acquires these leases and incorporates their reserves into the La Ventana Mine plan, these problems could perhaps be overcome. The leases would probably be surface mined. In their present status it is unlikely that individual mines on these blocks could ever compete.

The final four lease blocks, one in Raton Mesa and three in the San Juan region, received unfavorable development prospect ratings by OTA and were judged to have minimal production potential. All four are isolated tracts with small reserves. Underground mines serving local markets once operated on them, but they have been closed for at least a decade because of safety, engineering, and economic problems. There is currently little or no effort on the part of the present lessee to develop new mine plans and no published expressions of interest on the part of outside parties to acquire the leases.

Production Potential

To summarize the production potential of existing Federal coal leases in New Mexico:

Two mines are currently producing about 9.7 million tons of coal per year; and by 1986 these two mines with approved mine plans are scheduled to produce 10.0 million tons. In addition, three mines which currently have mine plans pending at DOI could be producing 6,6 million tons, and one mine which is now in the premine-plan stage could be producing 0.2 million tons by 1986.

By 1991, the six existing and proposed mines are scheduled to produce between 19.0 million and 23.0 million tons. One other mine is due to begin production after 1986, and is scheduled to produce between 0.7 million and 6.0 million tons by 1991. Total 1986 production from mines on existing leases is projected to be 16.8 million tons and 1991 production is projected to be between 19.7 million and 29.0 million tons.

If these projections hold true, 6 of the 16 lease blocks covering 79 percent of the leased reserves will be included in active mining operations in 1986. By 1991, 7 lease blocks covering 20 of the 29 New Mexico coal leases and over 98 percent of the coal reserves under lease are likely to be associated with active mining projects.

The DOE 1985 production goals of 33 million to 44 million tons are higher than OTA's estimate of potential 1986 production from Federal mines of 16.8 million tons. The OTA task force estimated that 1986 total State production would be 30 million tons, and recent New Mexico Energy and Minerals Department estimates have set planned production from all mines in the State for 1985 at 47 million tons. Most of any shortfall between the DOE goals and potential Federal mine production in 1985 to 1986 would probably be absorbed by mines on Indian and non-Federal reserves, which currently provide more than half of New Mexico's annual coal output.

For 1991, the OTA task force estimated that the maximum production potential of all mines in the State would reach 72 million tons—higher than both the DOE 1990 high level goal of 67 million tons and the recent State government estimate of 68 million tons of production in 1990. According to OTA's analysis, production from mines with existing Federal leases could reach 20 million to 29 million tons in 1991.

Actual production levels could vary from the OTA's projections. Several obstacles to coal mining could lower actual production below these projections, while the removal of some barriers to development and a strong coal market could cause production to increase above these levels.

A key determinant of actual coal production from New Mexico leases will be the level of out-of-State utility coal demand specifically and coal market considerations generally. A market study prepared for OTA concluded that the price competitiveness of New Mexico coal in major Eastern and Western markets is considerably underestimated. ” Actual market demand will depend on a wide range of issues including the growth of electric consumption, coal supply decisions of Texas utilities (Texas is the major potential new market for New Mexico coal), and the growth or decline in coal use relative to substitute fuels for power generation. Within New Mexico, the rate of commercialization of synfuels technology and the possible construction of additional powerplants to serve out-of-State customers are two additional factors bearing heavily on demand.

The lack of rail service to the central portion of the San Juan basin is the second most significant factor affecting the growth rate of New Mexico coal production, As explained above, the proposed Star Lake Railroad is in an advanced planning stage, but a right-of-way acquisition problem could still delay or prevent its construction.

Other major issues and uncertainties that will affect the future of the New Mexico coal industry include environmental impacts, land-use conflicts, socioeconomic impacts on local communities, and the amount of additional Federal reserves made available for mining through PRLAs and new lease sales. Mining and associated industrial development such as synfuels plants pose potentially unacceptable and unavoidable air quality impacts in this arid region. Mining in the Bisti area conflicts with protection of three wilderness study areas and with potentially important archeological and paleontological sites. An exchange of existing leases for new Federal coal to avoid some of these conflicts is under consideration. (See discussion in ch. 9.) Demand for adequate water supplies for mining, reclamation, synfuels development, and community needs and the need to protect water supplies from possible degradation could create conflicts between coal development and other users. Because of the arid climate, sparse vegetation, and high susceptibility to wind and water erosion, reclamation of surface-mined lands in the San Juan basin may prove more difficult than in other areas of the West, This difficulty is not, however, expected to restrict mine development. Most of the expanded coal development on Federal leases in New Mexico will occur in areas that are relatively isolated and sparsely populated. Associated population increases and demands for community services will impose additional administrative and financial requirements on the existing communities, Moreover, because Native Americans own or occupy substantial acreages throughout the basin, resolution of potential conflicts between mining and Native interests will require cooperation with tribal governments and the U.S. Bureau of Indian Affairs. (See ch, 12.)

There are currently twice as many acres under PRLAs than under existing leases in New Mexico. Processing of PRLAs in New Mexico will have a significant effect on the future of Federal coal development there. Two proposed Federal mines could be adversely affected by loss of reserves if adjoining PRLAs are rejected. New leased re-

See Energy and Environmental Analysis, Inc., *Feasibility of Using Cool Market Projections To Appraise Potential Production of Federal Coal Leaseholds*, draft report, May 1980.

serves from other PRLAs will compete in the market with other Federal and non-Federal coal currently available for mining.

Utah

Overview

Utah has the largest number of Federal coal leases of any State. There are 204 leases currently outstanding in Utah covering over 279,000 acres and more than 3.2 billion tons of recoverable coal reserves. Utah also has 25 pending PRLAs totaling over 75,000 acres and containing over 1 billion tons of recoverable reserves. According to U.S. Geological Survey (USGS) estimates, about 82 percent of the coal resources in Utah are federally owned, This high percentage is due, in part, to the fact that most of the coal deposits occur in the rugged mountainous terrain and the upland plateaus of central and southern Utah—areas that have largely remained in Federal ownership, while State and private land selections, land grants, and homesteads were concentrated in the valleys and flatlands. Most of Utah's known coal reserves are underground minable.

Utah has two major coal regions: the Uinta region which includes the Wasatch Plateau, Book Cliffs, and Emery coalfields in central Utah; and the Southwestern Utah coal region, which includes the Alton, Kolob, Kaiparowits Plateau, and Henry Mountain coalfields.* There are 108 Federal leases in the Uinta region and 96 leases in the Southwestern Utah region. The recoverable reserves are divided almost equally between the two regions.

Nearly 65 percent of the Federal leases in Utah are part of existing or proposed mines and thus their development and production plans are included in mine plans filed with DOI. The 14 mines with approved mine plans are all located in the Uinta region and contain 50 Federal leases with a total of 792 million tons of reserves, Eleven new mines have been proposed covering another 78 leases and 1.3 billion tons of reserves. Over 1 billion tons of new mine plan reserves are contained in the three proposed new mines in the Southwestern Utah region. The remaining 76 Federal leases without mine plans include several large tracts of good quality minable reserves that could be producing by 1990, as well as many smaller tracts that once supported small mines that will probably not be reopened. The Uinta region has 44 undeveloped leases and about 447 million tons of undeveloped reserves, The Southwestern Utah region has 32 undeveloped leases with 744 million tons of reserves—most of which are on the Kaiparowits Plateau.

Production Potential

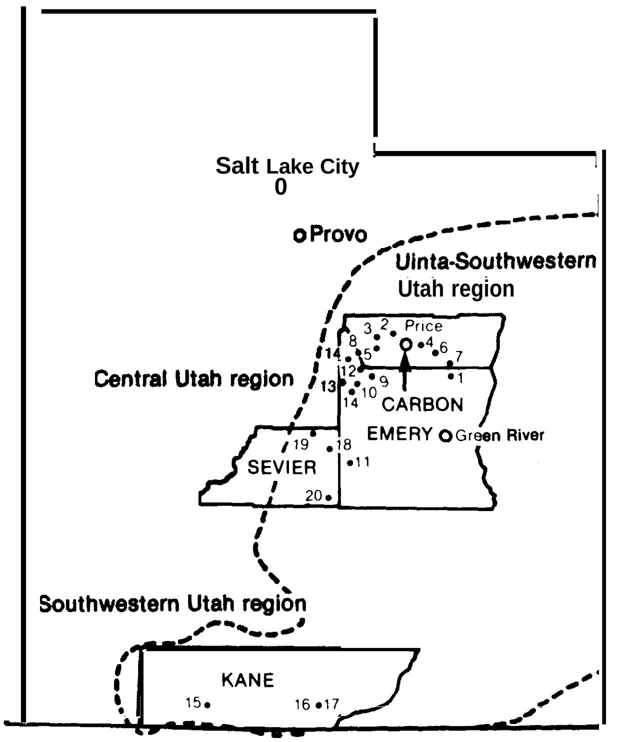
In 1979, Utah mines produced 11.8 million tons of coal with 10.4 million tons of this from mines with Federal leases. Federal production was 6.9 million tons in 1979 and came from 27 leases. In 1980, total State production increased to 13.1 million tons with 8.7 million tons coming from Federal reserves. All production in the State came from underground mines in the Uinta region. Figure A-3 shows the location of active and proposed mines with Federal leases in Utah.

Most of the coal produced was used by electric utilities, but a significant portion (about 1 million to 2 million tons) was used by the steel industry. About 40 to 50 percent of the coal produced in 1979 was used in the State; the rest was exported to consumers in the Southwest, west coast, and Midwest, Up to 2 million tons reportedly was stockpiled in 1979 because of soft market conditions. However, by the end of 1980 most, if not all, of Utah's excess production had been sold, in part, because of increased foreign export sales. In 1981, at least one Utah Federal mine was shipping coal under contract to Asian markets,

Coal production and mine capacity in Utah are expected to increase substantially during the 1980's as new mines are opened and existing mines reach full capacity. Production from mines with Federal leases will account for most of the growth. By 1986, total output from mines with Federal leases is expected to be as much as 30.2 million tons with up to 6.2 million tons of this coming from proposed new mines. By 1991, production from mines with Federal leases is expected to reach as high as 47 million to 74 million tons. About 7 million to 8.6 million tons could come from undeveloped leases in central Utah. Up to 25 million tons of coal could come from new mines in Southwestern Utah. The total capacity of existing mines on Federal leases at full production is 32.2 million tons per year, If all the pending mine plans went into production they would add 43 million tons of annual capacity. OTA estimates that the undeveloped leases could support an additional 18.5 million to 28.0 million tons of annual capacity. Southwestern Utah Federal coal produc-

* The BLM coal productlon region Uinta-Southwestern Utah combines the Uinta coal region of Utah and Colorado and the Southwestern Utah coal region into a single region for coal management program and production target purposes.

Figure A-3.—Coal Mines on Federal Lands in Utah



Map locations

1- Geneva
1- B Canyon
2- Braztah
3- C & W No. 1
4- Pinnacle (Deadman)
5- Gordon Creek No. 2
6- Sage Point-Dugout Canyon
6- Soldier Canyon
7- Sunnyside Nos. 1, 2, 3
8- Belina No. 1
8- O'Connor
8- Skyline
9- Star Point Nos. 1, 2
10- Des-Bee-Dove
10- Wilberg-Deercreek
11. Emery
12- Hiawatha Complex
13- Huntington Canyons Nos. 4, 5
14- Trail Mountain
15- Alton
16- Kaiparowits
17- Red and Blue
18- Convulsion Canyon (Sufco)
19- Skumpah Canyon
20- Ute Nos. 1, 2

tion could grow from nothing in 1979 to over 25 million tons in 1991, with an estimated total annual capacity of 36.3 million to 45.8 million tons. However, it is highly uncertain whether such levels of production would be achieved in the Southwestern Utah region because of the major transportation, economic, and environmental disadvantages facing coal development there.

OTA's estimate of planned production from mines with Federal leases in Utah of 30 million tons in 1986 agrees with the DOE 1985 midlevel production goal of 30,2 million tons, but is considerably higher than OTA's Utah task force estimate of 1985 production of between 15 million and 18 million tons. At least part of the difference between the conservative task force estimates and the OTA estimates and DOE goals is due to deferred powerplant construction. For 1991, OTA found that potential Federal mine production ranged from 47 million to 74 million tons with about 25 million tons of production in Southwestern Utah classified as uncertain. In comparison, the task force projected that 1990 production would range from 18 million to 40 million tons, with a likely level of 30 million tons which excludes any production in Southwestern Utah or for synfuels development. The DOE 1990 production goals for Utah range from a low of 36 million tons to a high of 63 million tons with a midlevel goal of 49 million tons.

The development and production potential of Federal leases in Uinta and Southwestern Utah coal regions are described in more detail in the following sections.

Central Utah

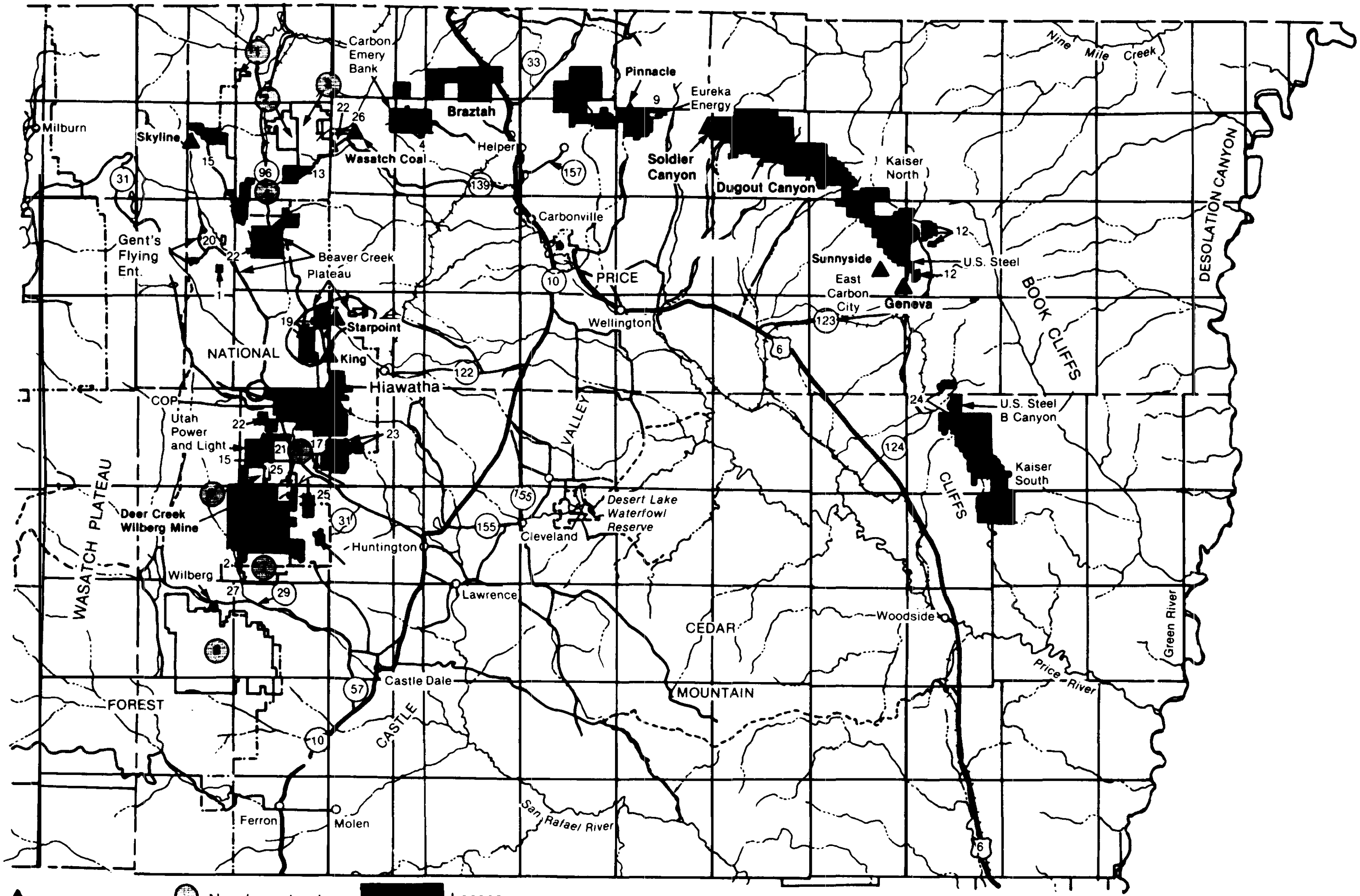
The central Utah portion of the Uinta region includes the Book Cliffs and Wasatch Plateau coalfields near the town of Price and the Emery coalfield near the town of Emery. The Book Cliffs and Wasatch Plateau coalfields are underground mining areas. The Emery Field has both surface and underground minable reserves. The central Utah coalfields have supported mining operations for over a century. Two active mines in the Book Cliffs Field—U.S. Steel's Geneva Mine and Kaiser Steel's Sunnyside Mine—supply metallurgical coal to their Western steel operations. The Wasatch Plateau Field is the major producing area in the State. (See figs. A-4 and A-5.)

There are 108 Federal leases outstanding in central Utah. There is only one pending PRLA in the region. * Federal leases in central Utah cover 128,930 acres and contain an estimated 1.5 billion tons of recoverable coal reserves, including about 21 million tons of surface recoverable reserves in the Emery field, The 50* * leases in the 14 mining operations with approved plans cover over 55,000 acres and more than 792 million tons of recoverable reserves and have a total maximum design capacity of 32.2 million tons per year. There are

* Possible impacts of issuance and development of this PRLA are examined in the Final Uinta-Southwestern Utah Coal Environmental Statement, February 1981.

**Three leases in the O'Connor mine area are also partly included in the approved mine plans for the Belina and Skyline mines,

Figure A-4.—Federal Coal Leases, PRLA's and New Lease Tracts Wasatch Plateau and Book Cliffs Fields



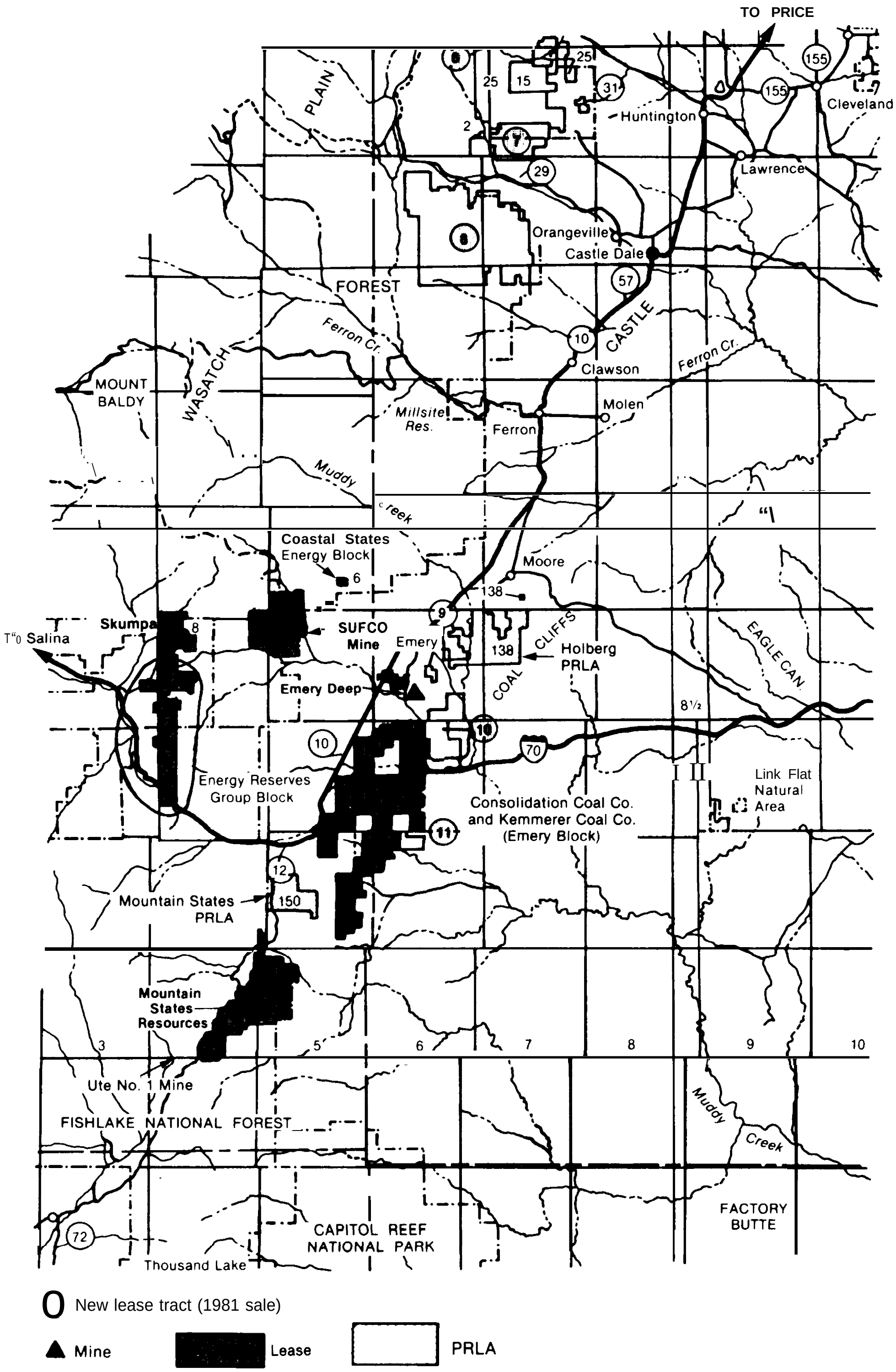
▲ Mines

New lease tract

Leases

SOURCE: U.S. Department of the Interior, Bureau of Land Management, *Uinta-Southwestern Utah Final Coal Environmental Impact Statement*, February 1981.

Figure A-5.— Federal Coal Leases, PRLA’s and New Lease Tracts in the Emery Coai Fieid, Utah



SOURCE U.S. Department of the Interior, Bureau of Land Management, Uinta-Southwestern Utah Final Coal *Environmental Impact Statement,* February 1981.

also eight proposed new mines in the Uinta region with 14 leases that are in pending mine plans. * These leases cover 25,711 acres and contain about 264 million tons of recoverable reserves. The proposed new mines have a total annual capacity of over 13 million tons per year.

The remaining 44 leases in central Utah are undeveloped. These leases cover 47,679 acres and more than 447 million tons of reserves. When the contiguous leases held by the same owners are grouped together into minable blocks, the undeveloped leases in central Utah form 20 lease blocks with 12 blocks each composed of only 1 lease.

The active mines in central Utah range from a few small underground operations producing less than 100,000 tons per year to new large mines producing over 1 million tons per year. Several mines are in the process of expanding their production capacities to produce up to 5 million tons per year or more by 1985, The 14 approved mining operations on Federal leases in central Utah are all underground mines and all, but the newly approved Skyline Mine, were producing in 1980, In 1980, over 8.7 million tons of production from Federal leases were reported to USGS for royalty purposes.

By 1986, production from operations with approved mine permits is projected to reach 24 million tons, more than double the 1979 production levels. By 1991, production from these mines could rise to 29 million tons. One small operation, the Trail Mountain Mine is expected to be depleted by 1991 unless it acquires additional reserves to maintain production. Both U.S. Steel's Geneva Mine and Kaiser Steel's Sunnyside Mine are expected to be nearing the limit of their economically recoverable reserves by the late 1980's and would then begin to shift production to new mines on their other Federal leaseholdings. OTA's mine plan review indicates that about 5 million of the 32.2 million tons of capacity on approved mine plans might not be constructed as planned because of changes in the lessee's captive coal needs out-of-State.

Six of the operating mines are captive operations, including two mines operated by steel companies, two complexes run by Utah Power & Light, the Soldier Canyon Mine run by California Portland Cement, and the Braztah Mine complex held by a subsidiary of American Electric Power (AEP) and supplying AEP powerplants in Indiana. Total production for these mines in 1979 was 6.1 million tons—over half the total production in the State. By 1986 captive production from Federal mines is expected to total about 13 million tons making a slight decline in its share of total State production. The captive segment of the Utah coal industry is expected to maintain it's position in the 1980's and 1990's since a significant amount of production from new mines on Federal leases would supply captive markets.

Pending Mine Plans.—The eight proposed new mines on Federal leases would, if all were developed as scheduled, add more than 13 million tons of annual production capacity in central Utah by 1990. One new mine, Eureka Energy's 3.2 million tons per year Sage Point-Dugout Canyon Mine, is intended to supply a new 1,600-MW coal-fired powerplant to be built by its parent Pacific Gas and Electric Co. U.S. Steel's new B Canyon Mine would replace the existing Geneva Mine when that operation reaches the limits of its economically minable reserves. Mountain States Resources' Ute Nos. l&2 mines near Emery would include both underground and surface operations. Several of the proposed new mines have been in planning stages for 5 years or more, however, mine permitting and construction activities have been deferred by the lessees because of soft market conditions and slower than expected electricity demand growth.

If all the proposed new mines meet their planned production schedules, six of the eight mines will be operating by 1986 with an estimated total production of 5.6 million tons. By 1991, all eight mines could be producing a total of 11.3 million tons according to the mine plan estimates. However, because at least two of the new mines are captive operations, their construction and production schedules are dependent on the needs of their parent companies. Current indications are that the Sage Point-Dugout Canyon Mine and the B Canyon Mine could be deferred several years, thus making about 4.2 million tons of 1991 production capacity somewhat uncertain.

Undeveloped Leases.—The 44 leases in central Utah without mine plans cover 47,679 acres and contain 447 million tons of recoverable reserves. These leases are 57.9 percent of the undeveloped leases, 42 percent of the undeveloped lease acres and 37 percent of the undeveloped Federal lease reserves in the State of Utah. The 44 undeveloped leases in the Uinta region are divided into 20 lease blocks ranging in size from 80 acres to more

"These leases include two leases that are partially included in two different mines: the newly approved Skyline Mine and the adjacent Belina and O'Connor mines which are dissected by several fault zones and the lessees executed operating agreements to mine those portions of the leases on their respective sides of the fault.

18,000 acres. Most of the reserves are underground minable only—however, one tract contains some surface recoverable reserves. About six of these lease blocks have supported some mining activities in the past. All of the undeveloped lease reserves in central Utah are bituminous with heat value of 11,000 Btu/lb or more, sulfur contents of 1.5 percent or less, and ash contents of 15 percent or less.

Eight undeveloped lease blocks with 30 leases have enough good quality minable reserves to sustain a new average-size mine of 500,000 tons per year with a 30-year mine life. These 30 leases contain a total of 417 million tons of recoverable reserves. The remaining 14 leases in 12 blocks did not have enough reserves for a new large mine. At least three of these blocks (six leases) have adequate reserves for a small mine, however. Two of the three blocks have been mined previously and probably would not be reopened because construction and safety costs would be prohibitive, Four undeveloped leases without enough reserves for a new independent mine are adjacent to active or proposed operation and could possibly be added to those mines through assignments or operating agreements,

After reviewing the quality and amount of reserves, the mining conditions, transportation availability and the expected market conditions over the next decade, OTA classified as favorable development prospects the eight lease blocks with adequate reserves to support new mines, These eight blocks with a total of 30 leases and 417 million tons of reserves have almost 95 percent of the undeveloped lease reserves in central Utah. Three one-lease blocks were rated as uncertain development prospects depending on the availability of additional reserves. The remaining 11 leases in nine lease blocks have unfavorable prospects for development.

The eight blocks with favorable prospects include two large tracts with a total of eight leases held by Kaiser Steel in the Book Cliffs Field and one very large block of eight leases in the Emery Field with more than 18,000 acres jointly held by Consolidation Coal Co. and Kemmerer Coal Co. Two other favorable blocks are held by companies with active mines on Federal leases: one lease block held by a subsidiary of ARCO, Beaver Creek Coal Co. (successor to Swisher Coal Co.), and a three lease block held by Energy Reserves Group, Inc., adjacent to its proposed Skumpah Canyon operation,

Three more blocks with favorable development prospects are located in a single township near two proposed Uinta new lease sale tracts and several active mines on existing leases. * These blocks include: one tract of five leases in Rilda Canyon owned by Utah Power & Light near its Deer Creek-Wilberg Mine; a two-lease block controlled by Nevada Electric Investment Co, adjacent to the Hiawatha Mine complex; and another block that was originally a single lease and was recently segregated into two leases, one assigned to Northwest Carbon Corp. and the other to COP Coal Development.

Development plans for four of the eight favorable blocks are known based on company interviews. Kaiser Steel plans to develop the two-lease Sunnyside North tract which has metallurgical coal reserves as replacement capacity for the existing Sunnyside Mine when it reaches the economic limits of its minable reserves. The block is not contiguous to the existing mine. The six-lease Sunnyside South block with lower quality, metallurgical-grade reserves could be mined for steam coal. Consolidation Coal, which already has one proposed mine on Federal leases in the Emery Field, plans to combine surface and underground mining operations in developing its remaining eight leases near Interstate 70 in Emery County, Utah Power & Light is expected to mine its five undeveloped leases as either a new mine or as an expansion of the Deer Creek-Wilberg Mine. Utah Power & Light is also actively seeking the Meetinghouse Canyon and Rilda Canyon new lease tracts adjacent to these lease blocks to supply its coal-fired powerplants.

The two blocks held by Beaver Creek Coal Co. and Energy Reserves Group will probably be mined when those companies shift operations from existing mines as they are depleted. Production plans for the two remaining blocks are unknown, however, it is expected that they will be developed since all three lessees involved own additional reserves in the same area and one lessee, Nevada Electric, is a major consumer of Utah coal.

The total estimated capacity that could be supported by the favorable lease blocks is 12 million tons per year, By 1986, none of the leases are expected to be producing, However, by 1991, the

*All of these blocks have been acquired by the current lessee within the past 2 years. One block of five leases was recently acquired by Utah Power & Light Corp. from Peabody Coal Co. Another block of leases was segregated and part was acquired by Northwest Carbon Corp. The remainder was assigned to COP Coal Development and another block was acquired by COP Coal Development Corp from Peabody. Another block is held by the Nevada Electric Investment, a subsidiary of Nevada Power Co.

leases could produce between 7,0 million and 8.6 million tons.

No production is estimated for the three leases with uncertain development prospects or for the 11 leases with unfavorable development prospects since these leases are not likely to be producing during the next 10 years unless they are combined with other reserves controlled by the lessee or mined as part of an adjoining operation, Two of the uncertain leases and four of the leases with unfavorable prospects are adjacent to or contiguous with existing or proposed mines.

Some of the major concerns involving coal development in central Utah are: potential impacts on water availability and water quality such as the interruption of springs due to subsidence, interception of aquifers during mining operations, discharges into streams, increased sediment load, and leaching of salts, trace elements, and heavy metals from strata disturbed during mining. Other concerns include: losses in wildlife habitat from expansion of the areas disturbed by mining; impairment of air quality; and population increases from mine development resulting in concentration of socioeconomic impacts in the Price-Helper area. These issues are addressed more fully in the environmental impact statements on central Utah coal development and the recently completed final environmental impact statement for the Uinta coal lease sales.

One area that could have substantial impacts from new mining on Federal leases is the Emery Field. The coal leases belonging to Consolidation and Kemmerer Coal companies are bisected by Interstate 70-a major tourist route, However, because the area would most likely be underground mined and the coal reserves in the vicinity of I-70 are of poorer quality, it is unlikely that any mining would be done near the highway. The Emery area is just west of the San Rafael Swell—a scenic area of geologic interest—and expansion of mining activities could contribute to increases in airborn particulate and to reduced visibility, especially during dry spells. The Emery Field is not currently served by rail transportation so existing mines truck coal to loadout facilities near Price. The proposed Castle Valley Railroad would extend along the Wasatch Plateau to the Emery coalfield. Construction of the railroad is dependent on expanded mine production in that area.

Southwestern Utah

The Southwestern Utah coal region includes the Alton, Kolob, Kaiparowits Plateau, and Henry Mountains coalfields. The Henry Mountains Field has no Federal leases, it does, however, have three PRLAs. The southwestern Utah coalfields have both underground and surface minable reserves, however, underground reserves predominate. There are no active mines in the region, although there were several small mines operating on Federal leases that supplied coal to local markets. Three new large mines have been proposed for the Alton and Kaiparowits fields. Proposed mining operations in the Alton Field have encountered substantial opposition from environmentalists because of its proximity to several major national parks, the possible impacts on visibility and ground water, and potential reclamation problems. Mining on the Kaiparowits Plateau has been opposed because it would occur in one of the last remaining undisturbed roadless areas in the United States outside of Alaska, and also because of potential air quality impacts.

There are 96 Federal leases in the Southwestern Utah coal region covering over 150,000 acres and 1.75 billion tons of recoverable coal reserves. The 24 pending PRLAs in the region cover an additional 72,000 acres and over 1.0 billion tons of recoverable reserves. Three new large mines have been preposed in southwestern Utah: The Alton Mine with combined surface and underground operations on 28 leases held by Nevada Power and Utah International, Inc.; and two proposed underground mines on the Kaiparowits Plateau—El Paso Energy Co.'s Red and Blue Mines and the Kaiparowits Mine on leases held by resource development subsidiaries of three Southwestern utilities. These three proposed mines include 64 of the existing leases in southern Utah and cover over 93,000 acres and over 1 billion tons of reserves.

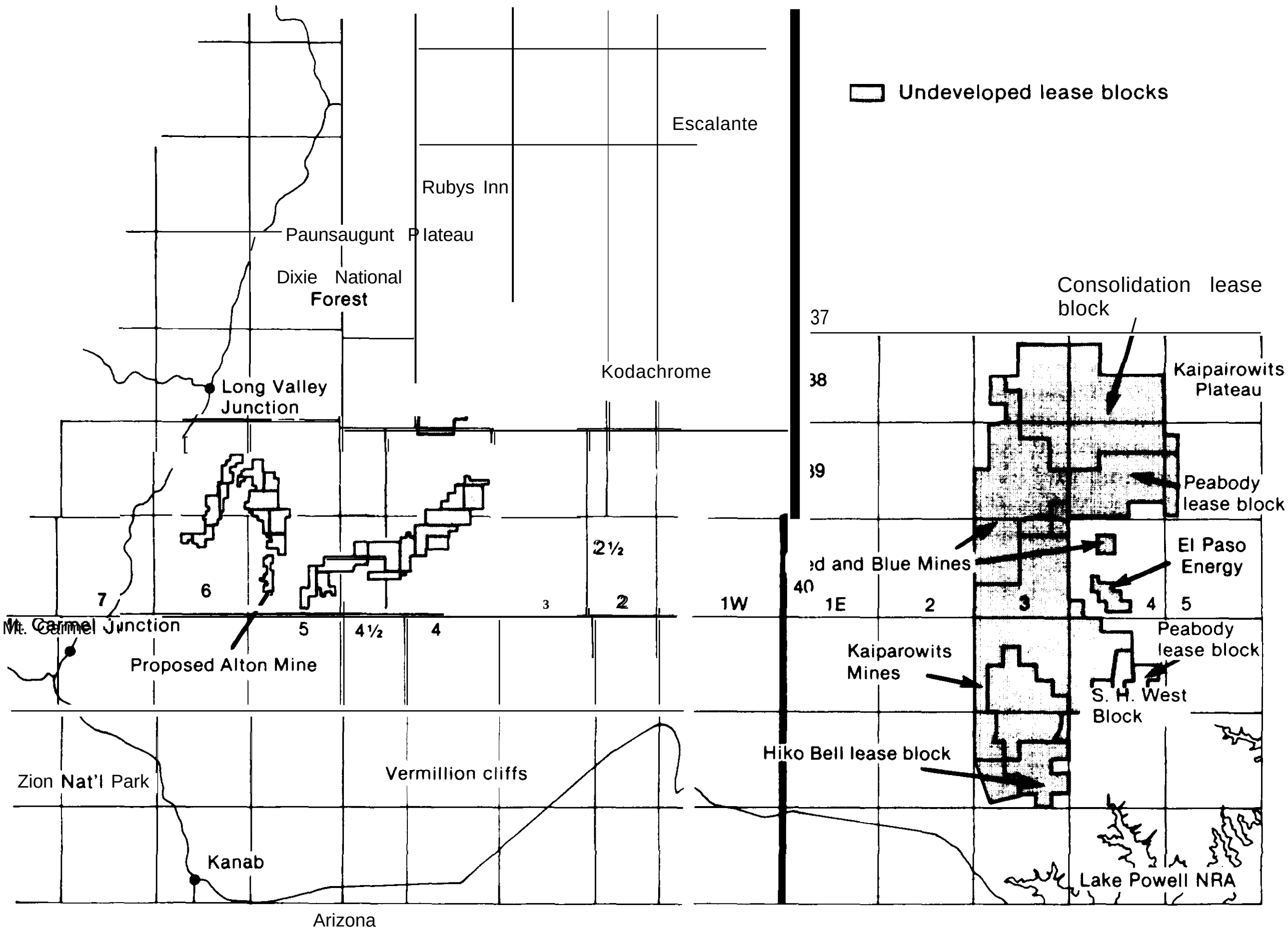
The remaining 32 leases cover over 57,000 acres and 743.5 million tons of recoverable underground reserves. These undeveloped leases are divided into 11 lease blocks—seven single lease blocks and four multilease blocks. Several of the leases supported small mines in the past. Six lease blocks with 27 of the leases are located in the Kaiparowits Plateau.

Pending Mine Plans.—The three mine plans proposed for southwestern Utah contain over 1 billion tons of recoverable reserves with about three-quarters of the reserves underground minable. The proposals include the Alton Surface Mine and two underground mines on the Kaiparowits Plateau. Total annual production capacity of the proposed mines is 30 million tons. Estimated production in 1986 is about 600,000 tons. If all mine plans were approved in the next decade, production in 1991 could be as much as 25.4 million tons. All of these proposals face substantial uncertainties over whether and when they will go into production, All are located in remote areas that are not currently active mining areas and which are not served by rail transportation. All present potential environmental conflicts. All have substantial uncertainties over where the coal will be sold.

The Alton Mine located near the town of Alton, just south of the Paunsaugunt Plateau and Bryce Canyon National Park, is probably the best known of the southern Utah mine proposals because of its location and concern over its potential impacts on the park (see fig. A-6). The Alton Mine is part of the Allen-Warner Valley Energy Complex and is the closest to development of any of the proposed mines in southwest Utah because it has successfully obtained several necessary permit approvals and, until recently, appeared to have a definite consumer for its coal production. But, recent developments have clouded its future and the operator, Utah International, Inc., has deferred initial production until at least 1986. The mine would initially be a surface mine, but after about 20 years of operation, would begin underground mining on more deeply buried reserves.

In December 1980, Interior Secretary Andrus issued his decision on the citizens' petition to declare Federal lands in the Alton coalfield un-

Figure A-6.– Federal Coal Leases in Southwestern Utah



SOURCE US Department of the Interior, Bureau of Land Management, *Uinta-Southwestern Utah* **Final Coal** *Environmental Impact Statement,* February 1981.

suitable for mining under the Surface Mining Control and Reclamation Act of 1977 (SMCRA). This was the first section 522 unsuitability petition accepted. Secretary Andrus declared Federal lands adjacent to Bryce Canyon National Park as unsuitable for surface mining and the surface effects of underground mining. The decision affected about 9,049 acres on the eastern side of the Alton Field out of the more than 26,000 acres leased by Utah International and Nevada Power. As a result of the decision, about 24 million tons of the more than 290 million tons under lease would not be minable. The decision cited the potential adverse impacts on the park from blasting, heavy truck traffic, air quality degradation, and noise from the mining operations which would have extended to within 5 miles of the Yovimpa Point lookout in Bryce Canyon Park. The original petition had requested that Andrus declare a total of 325,000 acres (240,000 acres of Federal land) as unsuitable for mining. The lessees have filed suit in Federal District Court in Salt Lake City challenging the adequacy of the technical information supporting the decision and alleging that the Alton leases should be exempt from the unsuitability provisions because of substantial legal and financial commitments to development made before passage of the act.

In Feburary 1981, two of the partners in the Allen-Warner Valley Power project, Southern California Edison and Pacific Gas & Electric, withdrew their applications for participation in the project from consideration by the California Public Utility Commission. The decision was, in part, based on the decisions by the Secretary of Interior and EPA to approve permits for construction of one portion of the project, the Harry Allen plant in Nevada, and to withhold approval of the smaller Warner Valley Plant in Utah pending additional study. Southern California Edison also attributed its decision to a shift in company policy to the use of renewable energy sources. Substantial questions thus still remain over construction of the two plants and of the proposed slurry line from the Alton Mine to the powerplants.

The Alton lessees have submitted an informal mine plan proposal for use in environmental analyses. The lessees have reportedly deferred submittal of a final plan until after the Alton unsuitability decision was made. The proposed mine would produce up to 11.2 million tons of coal annually. The impact of the unsuitability petition on development is still unclear—about 10 percent of the reserves were withdrawn from production. Should the decision stand, the lessees are expected to seek an exchange of the affected leases for other comparable Federal coal lands in the area. Interior had previously indicated it would give prompt attention to such a request.

Two mine plans have also been submitted for underground mines on the Kaiparowits Plateau. El Paso Energy proposes to open a large underground mine complex on its 40,00()-acre” lease tract. The first two mines, the Red and Blue Mines, would produce a total of about 1.1 million tons per year. El Paso plans to expand production on the plateau in other reserve areas to reach an eventual annual capacity of 6.8 million tons per year.

The Kaiparowits Nos. 1-5 complex is proposed by a consortium of three resource development subsidiaries of electric utilities: Mono Power, a subsidiary of Southern California Edison; Resources Co., a subsidiary of Arizona Public Service Co.; and New Albion Resources Co., a subsidiary of San Diego Gas & Electric Co. These leases are located on the southern portion of the plateau just south of the El Paso leases. The lessees plan to open several underground mines on the jointly held lease tract of over 47,000 acres which would eventually produce 12 million tons per year. The leases were originally acquired as PRLAs and were intended to supply electric utilities in the Southwest or, possibly, a powerplant near the mine area. Because of concerns about impacts on the region’s air quality and water supply, powerplant construction at or near the mine complex to serve out-of-State consumers is now considered unlikely.

Development of the two planned mines on the Kaiparowits Plateau is uncertain. Both mine plans were submitted before the implementation of SMCRA and have not been updated to reflect the current mine plan requirements. The major uncertainties affecting their development are lack of transportation to move coal to market and lack of any definite market for the production. Estimates by the Union Pacific Railroad are that a minimum production of 30 million tons per year would be necessary to offset the costs of construction of a rail line to the plateau. The two proposed mines would produce 18.8 million tons at full capacity—just over 60 percent of the minimum required production. It is very uncertain whether a market for the required 30 million tons or more of Kaiparowits coal will materialize over the next decade. An additional factor that affects the development of these mines is the remote location and the need to provide a supporting infrastructure for mine development. The nearby communities are few, small, and far between, Mine construction would bring an increase in population and greater demand for services such as roads, utilities, water, and housing to serve the mine employees. These requirements could put southwestern Utah development at a disadvantage when compared to other established mining areas.

Undeveloped Leases.—There are 32 undeveloped leases in southwestern Utah. These leases cover 57,537 acres and 744 million tons of recoverable underground reserves. The leases are divided into 11 lease blocks, 7 of these are single lease blocks ranging in size from 40 to 1,440 acres. There are four multilease blocks ranging in size from 6,400 acres to more than 25,500 acres, Six of the lease blocks are located on the Kaiparowits Plateau, and the five others are small leases that are scattered across the region. Four of the five small lease blocks have previously operated as small mines but were shut down in the 1950's and 1960's as local markets diminished.

In reviewing the development potential of these lease blocks, OTA found that four of the six tracts on the Kaiparowits Plateau each had sufficient reserves of good quality coal that could support independent mining operations. These four blocks include two separate tracts held by Peabody Coal Co., one large tract on the northern portion of the Plateau held by Consolidation Coal Co., and a three-lease tract held by Hiko Bell Oil & Mining Co. on the southern edge of the plateau near the Glen Canyon Recreation Area withdrawal. Two tracts on the plateau did not meet the minimum quality and reserve requirements for new mines. One block held by El Paso has difficult mining conditions relative to the lease configuration and is separated from the company's other leases in the Red and Blue mine plan proposal, The other block, a lease owned by an individual, is on the southern portion of the plateau with generally lower quality reserves and more difficult problems of access to the seams because of topography.

All of the leases on the Kaiparowits Plateau are in an isolated, rugged area, not served by existing transportation systems capable of moving coal to market. Access for mine development is difficult because of the steep, highly dissected cliff faces of the plateau and the complex geology of the multiple coal seams. The area would require more exploratory and developmental drilling, and construction of roads, utility lines and other supporting services before substantial mining operations could begin. The 25 leases in the four lease blocks on the plateau that could support new mines were thus rated as having uncertain development prospects. The two single lease tracts were classified as unfavorable development prospects.

The five remaining small lease tracts in Southwestern Utah were found to have unfavorable development prospects as new mines. They generally did not have sufficient reserves to support a new large mining operation. Their locations made them potentially suitable to serve limited local markets only, The reserves on the small tracts are also generally poorer quality coals. Two leases located near Zion NationaI Park have some potential environmental problems (wildlife and water quality impacts) although they have been mined in the past and are not located in highly visible areas so they would not, as compared to Alton, pose a visual intrusion onto the park areas.

An analysis of the production potential of the four tracts on the Kaiparowits Plateau with uncertain development prospects indicated that they could support a total annual production of 7 million to 16 million tons depending on the choice of mining technologies and mine life. This calculation was made on the basis of available information on the reserves, geology, topography and possible mining conditions that could be encountered. Full production capacity is expected to be attained in 3 to 6 years from initial commercial production. At a minimum, because of the time needed for mine plan development and other construction, it was estimated that 1987 is the earliest date that production could begin on the plateau. This date assumes 2 years for mine plan submittal, another 2 years for approval of the mine plan and other permits, and about 2 to 3 years of preliminary mine development and construction. It is not known how long it would take to construct the required railroad or supporting community infrastructure. If the potential 7 million to 16 million tons annual production capacity from the undeveloped leases is added to the 18 million tons of production proposed from the Kaiparowits and El Paso mine complexes, the annual regional production approaches the range required to support construction of the rail line. It was suggested in the regional environmental impact statement for Southwestern Utah that initial production from mines could be trucked to Page, Ariz., and used for power generation there—however, that appears an unlikely alternative at present. It is becoming clear, however, that development of existing Federal leases on the Kaiparowits Plateau is very much an all or nothing proposition.

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APPENDIX B

OTA Working Lease List and Lessee Index

COLORADO - Green River Region

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Consolidated Gas & ° 1 Corp./ Sunland Mining Corp.	Apex No. 2	Approved	2	C0127592	10/1/66	80	Routt
				D046544	12/3/37	160	
						240	
General Dynamics Corp./Material Service Corp. --Peabody Holding Co./Peabody Coal Co	Seneca 2W	Approved	[illegible]	C081251	5/1/65	2519	Koutt
				C081258	5/1/65	2323	
				C19885	7/1/63	125	
						4967	
General Electric Co./Utah International, Inc.	Trapper	Approved	[illegible]	C25948	12/1/66	85	Moffat
				C07518	6/1/58	2566	
				C07519	6/1/58	1372	
				C079641	10/1/62	1352	
						5375	
Getty Oil Co./Energy Fuels Co.	Energy Fuels No. 1 & 2	Approved	7	C0128433	6/1/75	475	Routt
				C081330	11/1/63	2215	
				C16284	7/1/78	263	
				C20900	11/1/78	420	
				C22644	7/1/79	1790	
				C22676	9/1/79	402	
				D052547	3/1/45	1145	
						6710	
Getty Oil Co./Kerr Coal Co.	Marr	Approved	1	C22777	7/1/80	770	Jackson
Gulf °il Corp./--	Edna Strip	Approved	4	C021601*	6/1/62	827	Routt
				D033327	4/23/25	280	
				D041478	5/6/30	80	
				D053710	6/10/47	89	
						1276	
Hanna Mining Corp. and W.R. Grace & Co./Colowyo Coal Co.	Colowyo Str:p	Approved		D034365	10/25/24	2545	Mof
Internorth Corp./Northern Minerals Co.	Meeker Area	Approved	[illegible]	C1545	9/1/67	896	Rio Blanco
				C28358	6/1/67	886	
				C28359	6/1/67	1000	
				C076713	2/1/66	320	
				D044240	1/12/33	160	
						3262	

*Lease #C°2150: is also in Gulf °il Corp.'s pending Trout Creek undergr❘ o mine plan.

COLORADO - Green River Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Kansas Nebraska Natural Gas Co./ Wyoming Fuels Co.	Canadian Strip	Approved	1	C27931	3/1/80	90	Jackson
Standard Oil of Indiana Co./Empire Energy Corp.	Eagle No. 5 & 9	Approved	3	C0126480 C0127865 D056298	1/1/66 1/1/66 12/1/49	367 43 41 451	Moffat
Gulf Oil Corp./--	Trout Creek	Pending	1	C021601*	6/1/62	827	Routt
Lombardi, Prosper/--	Johnnie's	Pending	1	C23396	1/1/79	80	Routt
Western Fuels Associates/--	Deserado	Pending	2	D047201 C023703	7/25/36 3/1/63	513 2557 3070	Rio Blanco
AMCA Resources/AMCA Coal Leasing, Inc.	--	Undeveloped	1	C030472	7/1/60	120	Jackson
AMCA Resources/AMCA Coal Leasing, Inc.	--	Undeveloped	1	D051376	10/8/40	250	Routt
American Electric Power Co./Franklin Real Estate Co.	Cardinal	Undeveloped	1	C012894	12/1/56	634	Routt
Chapman, Russell W. and Riebold, Paul	--	Undeveloped	1	C028875	11/1/31	1675	Rio Blanco
Conoco, Inc./Consolidation Coal Co.	--	Undeveloped	2	C093714 C093715	6/1/67 6/1/67	571 760 1331	Rio Blanco
Conoco, Inc./Consolidation Coal Co.	--	Undeveloped	1	C1546	9/1/67	1097	Rio Blanco
Conoco, Inc./Consolidation Coal Co.	--	Undeveloped	1	C245	1/1/66	226	Rio Blanco
Conoco, Inc./Consolidation Coal Co.	--	Undeveloped	2	C093713 C093716	6/1/67 6/1/67	2518 2061 4579	Rio Blanco

*Lease No. C021601 is also in Gulf Oil Corp.'s approved Edna Strip Mine.

COLORADO - Green River Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Conoco Inc./Consolidation Coal Co. and Gulf Oil Corp./Kemmerer Coal Co.	--	Undeveloped	1	C0105299	6/1/68	560	Jackson
Conoco Inc./Consolidation Coal Co. and Gulf Oil Corp./Kemmerer Coal Co.	--	Undeveloped	1	C0105300	6/1/68	1680	Jackson
Conoco Inc./Consolidation Coal Co. and Gulf Oil Corp./Kemmerer Coal Co.	--	Undeveloped	1	C° 23177	8/1/66	1707	Jackson
General Electric Co./Utah International, Inc.	-	Undeveloped	1	C0123476	12/1/66	2252	Moffat
General Electric Co./Utah International, Inc.	--	Undeveloped	1	C813	4/1/70	160	Moffat
James, Ferne M. estate)/--	--	Undeveloped	1	C064416	1/1/66	40	Moffat
Kansas Nebraska Natural Gas Co./Wyom ng Fuels Co.	--	Undeveloped	1	D057166	6/21/51	173	Jackson
Occidental Petroleum Corp./Sheridan Enterprises, Inc.	Joe's	Undeveloped	[illegible]	D052546	9/27/48	160	Routt
Peabody Holding Co./Peabody Coal Co.	Seneca	Undeveloped	1	C0114093	5/1/64	1320	Routt
Peabody Holding Co./Peabody Coal Co.	--	Undeveloped	1	C086654	7/1/63	160	Routt
Peabody Holdi Co./Peabody Coal Co.	Seneca II	Undeveloped	1	C08819	7/1/63	2280	Routt
Ruby Construction Co./--	Sun	Undeveloped	1	D051698	9/11/41	146	Routt
W.R. Grace & Co./--	--	Undeveloped	1	C0125957	10/1/65	3863	Moffat

COLORADO - Uinta Region

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Atlantic-Richfield Co./--	Bear	Approved	1	D044569*	8/30/34	1340 (1000 adj.)	Gunnison
General Exploration, Inc./Cambridge Coal Co.	Roadside	Approved	1	C078049	[illegible]/1/66	81[illegible]	Mesa
General Exploration, Inc./GEX Colorado	Cameo	Approved	1	C01538	6/1/5[illegible]	2560	Mesa
Northwest Energy Corp./Western Slope Carbon, Inc.	Hawksnest Eas[illegible]	Approved	[illegible]	C17130	12/1/73	241	Gunnison
				C27103	10/1/79	290	
				D042921	2/25/31	819	
				D056724	12/1/50	189	
						1539	
Mid Continent Resources, Inc.	Coal Basin	Approved	9	C12640	5/1/66	1529	Gunni
				C0115606	1/1/65	80	
				C011646	10/1/58	957	
				C0125456	4/1/61	80	
				C030345	4/1/61	117	
				C074632	12/1/66	680	
				C0125457	10/1/58	1142	Pitkin
				C09004	5/1/61	1529	
				C09005	11/1/58	1365	
						7479	
U.S. Steel Corp. —	Somerset	Ap	3	C033301**	1/7/60	625	Delta
				C033302	1/7/64	1548	
				D052504	8/19/44	3470	
						5643	
Weaver, Henry L. and Opal/--	Ohio Creek No. 2	Approved	1	C069942	4/[illegible]/62	80	Gunnison
Westmoreland Coal Co./Colorado Westmoreland Inc.	Orchard Valley	Approved	2	C25079	3/1/78	310	Delta
				C27432	9/1/79	854	
						1164	

*Lease No. D044569 is being mined by Tony Bear Coal Co. under sublease from Atlantic Richfield Co. It is also in Atlantic-Richfield Co.'s Mt. Gunnison pending mine plan.

**Lease C033301 is also part of the proposed Blue Ribbon Mine which is under sublease to Sunflower Energy as operator for U. . Steel Corp.

COLORADO – Uinta Region continued

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Anschutz Corp./--		Pending	2	C08172 C08173	6/1/58 6/1/58	2413 2469 4882	Pitkin
Atlantic-Richfield Co./--	Mt. Gunnison No. 1	Pending	3	C011792 C01362 D044569*	6/1/65 9/1/67 12/27/77	1243 4836 1340 7420	Gunnison
Eastern Gas & Fuel Associates and NICOR, Inc./Belden Enterprises	Colby Red Canyon	Pending		D036906	4/1/2[illegible]	41	Delta
Mid Continent Resources, Inc./ Mid Continent Limestone Co.	Coal Canyon	Pending	3	C037277 C059420 D040389	10/1/62 10/1/65 5/21/32	1471 308 241 2021	Mesa
Occidental Petroleum Corp./ Sheridan Enterprises, Inc.	Complex	Pending	6	C0125436 C0125437 C0125438 C0125439 C0125515 C0125516	5/1/68 5/1/68 5/1/68 5/1/68 5/1/68 5/1/68	2446 2357 2560 2483 2560 2523 14929	
Pitkin Iron Corp./-- --James Brothers Coal Co. -- --James, Richard, Jr., James, Kermit L., and Pitkin Iron Corp.	Cottonwood Creek	Pending	3	C020740 C029889 C024998	10/1/58 11/1/64 10/1/63	40 2522 2551 5113	Mesa
St. Joe Minerals Corp./Anchor Coal Co.	Windjammer	Pending	1	D05250	8/20/45	280	Gunnison
U.S. Steel Corp./--	Blue Ribbon	Pending	1	C033301**	1/7/60	625	Gunnison
Garland Coal & Mining Co./--	Thompson Creek	Undeveloped		C012765	6/ /60	498	Pitkin
General Electric Co./Utah International, Inc.	Green Valley	Undeveloped	1	D055156	10/18/48	174	Delta

*Lease No. D044569 is being mi[illegible] by Tony Bear Coal Co. under sublease from Atlantic-Richfield Co. It is also in Atlantic-Richfield Co.'s Mt. Gunnison pending mine plan.

**Lease C033301 is also part of United States Steel Corp.'s approved Somerset Mine.

COLORADO - Uinta Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Gulf Oil Corp. --	Paonia Farmer's	Undeveloped	1	D036955	12/28/23	280	Delta
Gulf Oil Corp./Kemmerer Coal Co.	Tongue Mesa	Undeveloped	6	C0120078	1/11/68	2000	Montrose
				C0120079	1/11/68	2560	
				C0120080	1/11/68	1600	
				D038385	3/1/29	360	
				C0120073	1/11/68	2240	
				C0120077	1/11/68	1242	Ouray
						10002	
Gulf Oil Corp./Kemmerer Coal Co.	Tongue Mesa	Undeveloped	1	C0120076	1/12/68	2320	Ouray
Thompson Creek Coal & Coke Co./--	--	Undeveloped	1	D037766	11/5/27	120	Gunnison
U.S. Steel Corp./--	Coal Basin	Undeveloped	8	C0125485	1/1/65	200	Gunnison
				C030344	5/1/60	517	
				C12638	1/1/65	315	
				C12639	12/1/66	800	
				C1894	12/1/66	120	
				C7852	12/1/66	160	
				C030346	5/1/60	640	
				C7853	1/1/65	717	
						3469	
U.S. Steel Corp./--	--	Undeveloped	1	C068389	9/1/61	560	Gunnison
U.S. Steel Corp. --	--	Undeveloped	1	C051669	9/1/61	1092	Gunnison
U.S. Steel Corp./--	--	Undeveloped	1	D05255[illegible]	8/19/44	214	Gunnison
Welch, Evelyn and Wiggins, Shirley/--	Harvey Gap	Undeveloped	1	D043937	4/5/32	120	Garfield

COLORADO
Denver-Raton Mesa and San Juan Region

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Denver-Raton Mesa							
Crane Co./CF&I Steel Co.	--	Undeveloped	1	C067	7/1/52	962	Los Animas
Martinez, Albert/--	--	Undeveloped	1	P058043	9/11/41	40	Los Animas
Peabody Holding Co./Peabody Coal Co.	Denver Basin	Undeveloped	3	C0112685 C0112686 C0112687	12/1/67 12/1/67 12/1/67	640 640 644 1924	Elbert
Peabody Holding Co./Peabody Coal Co.	Denver Basin	Undeveloped	1	C0126477	12/1/67	760	Elbert
San Juan Region							
National King Coal, Inc. --	King Coal	Approved	1	P058300	[illegible]1/41	160	La Plata

MONTANA - Powder River Basin

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Montana S. Wester[illegible] Energy Co.	Rosebud	Approved	5	B020989	5/5/23	1446	Rosebud
				M073109	9/1/66	5792	
				M35734	8/1/79	480	
				N34735	8/1/79	447	
				N42381	6/1/80	62	
						8226	
Pacific Power & Light Co./Spring Creek Coal Co.	Spri[illegible] Creek	Approved	[illegible]	M069782	7/1/65	2347	Rosebud
Pacific Power & Light Co. and Peter Kiewit Sons, Inc./Decker Coal Co.	East Decker	Approved	[illegible]	M073093	8/1/66	9410	Big Horn
Pacific Power & Light Co. and Kiewit Sons, Inc./Decker Coa	West Decker	Approved	[illegible]	M06770	1/1/54	40	Big Horn
				M057934A	1/1/63	1841	
				M061685	3/1/64	2360	
				M057934	10/1/63	720	
						4961	
Peabody Holding Co./Peabody Coal Co.	Big Sky	Approved	1	M15965	4/1/71	4307	Rosebud
Inc. olidati[illegible] Co.	CX Ranch	Undeveloped	1	M46292	3/1/64	674	Big Horn
Peter Kiewit Sons, Inc./Rosebud Coal Sales Co.	CX Ranch (PKS)	Undeveloped	1	M061686	3/1/64	524	Big Horn
Shell Oil Corp. --	Pearl	Undeveloped	1	M069945	7/1/65	541	Big Horn

MONTANA - Bull Mountains and Yellowstone Region

PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Bull Mountains							
Divide Coal Mining Co. --	Divide	Approved	1	M052647	11/1/62	80	Musselshell
Johnson, G. and A./--	Johnson	Undeveloped	1	B028531	3/3/28	80	Musselshell
Yellowstone Region							
Bugni, A., T. and R./--	Bugni	Undeveloped	1	GF082523	8/6/42	80	Madison

MONTANA - Fort Union Region

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Montana-Dakota Utilities/Knife River Coal Mining Co.	Savage	Approved	1	M023207	3/1/57	960	Richland
U.S. Steel Corp. --	U.S. Steel	Undeveloped	2	M3831	12/1/67	2537	Dawson
				M3832	12/1/67	2559	
						5096	

NE – San Juan

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Gulf Oil Corp./--	McKinley	Approved	4	NM057349 NM057348 NM0554844 NM065466	4/1/61 4/1/61 1/1/64 1/1/64	2513 2485 540 2560 8098	McKinley
Public Service Co. of New Mexico and Tucson Electric Co./ Western Coal Co.	San Juan	Approved	[illegible]	NM071448 NM045197 NM045217 NM045196 NM28093	6/11/40 11/1/61 11/1/61 11/1/61 4/1/80	40 2565 1800 2467 3856 10728	San Juan
Ideal Basic Industries, Inc. --	La Ventana	Pending	[illegible]	NM0510466 NM0510467 NM0510468 NM0555316 NM0555317	7/1/67 7/1/67 7/1/67 2/1/69 12/1/64	2002 2433 2505 160 2206 9306	Sandoval
Peabody Holding Co./Peabody Coal Co. and Thermal Energy Co./--	Star Lake	Pending		NM2457	9/1/67	6336	McKinley
Public Service Co. of New Mexico and Tucson Electric Co./ Western Coal Co.	Bisti	Pending	[illegible]	NM1086612 NM0186613 NM0186615	8/1/61 8/1/61 8/1/61	2188 1240 2027 5455	San Juan
Amtex Corp. --	--	Undeveloped	1	SF048323	7/19/29	120	Sandoval
Amtex Corp. --	--	Undeveloped	1	NM732	2/1/67	160	Sandoval
Cimma Coal Co./--	La Plata	Undeveloped	1	NM0315559	8/1/63	2044	San Juan
Eastern Gas & Fuel Associates/ Eastern Associated Properties Corp. and Texas Eastern Transmission Corp./Fannin Square Corp.	Black Lake	Undeveloped	1	NM10931	11/1/70	1910	San Juan
Ingraham, Floyd E. --		Undeveloped	[illegible]	SF0771 [illegible]	2/27/44	60	San Juan

NEW MEXICO - San Juan Region (continued) and Denver-Raton Mesa Region

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Padilla, Florentino/--	--	Undeveloped	2	SF075321 SF077779	12/11/39 5/1/49	120 40 160	Sandoval
Simmons, James L. --	--	Undeveloped	1	SF076644	[illegible]	80	Rio Ariba
Denver-Raton Mesa Region							
Davis, Robert Lee/--	--	Undeveloped	1	SF07467[illegible]	1/10/41	40	Colfax
Texas Industries, Inc./--	--	Undeveloped	1	SF066817	1/25/35	120	Colfax
Urtado, Barney/--	--	Undeveloped	1	SF042800	4/8/24	41	Colfax

NORTH DAKOTA - Fort Union Region

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Conoco, Inc./Consolidation Coal Co.	Glenharold	Approved	3	M070203	11/1/65	477	Mercer & Oliver
				M11269	5/1/71	260	Oliver
				M21209*	11/1/79	1688	Mercer
						2305	
Montana-Dakota Utilities/Knife River Coal Mining Co.	Gascoyne	Approved	1	BLM019127	1/1/51	2872	Bowman
Montana-Dakota Utilities/Knife River Coal Mining Co.	South Beulah	Approved	2	M041765	8/1/61	1600	Mercer & Oliver
				M43083**	8/19/80	80	Mercer
						1680	
North American Coal Corp./--	Indian Head	Approved	2	BK020273	10/2/22	1357	Mercer
				M34980	4/1/79	441	
						1798	
Baukol-Noonan, Inc./--	Center	Pending	1	M043848	1/1/62	2325	Oliver
North American Coal Corp./ Coteau Properties, Inc.	Beulah-Hazen	Pending	2	M071813	11/1/67	2034	Mercer
				M042819**	10/1/61	764	
						2798	
North American Coal Corp./ Falkirk Mining Co.	Falkirk	Pending	1	M31053	8/1/80	160	McClean
American Colloid Co. --	American Colloid	Undeveloped	1	M061025	3/1/64	80	Williams

*This lease is in a pending mine plan; however it has been grouped with leases in approved mine plans for the purposes OTA's analysis because of its association with the two leases in the Glenharold Mine plan.

**These leases, although not included in a mine plan, are closely associated with a lease or leases in an approved (or pending) mine plan. They have therefore been grouped with leases in approved (or pending) mine plans for the purposes of OTA's analysis.

NORTH DAKOTA - Fort Union Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Bonsness, Leroy --	Leroy Bonsness	Undeveloped	1	BLM018322*	/1/51	80	Burke
Conoco, Inc./Consolidation Coal Co.	Renner's Cove	Undeveloped	1	M37829	3/1/67	322	Mercer
Conoco, Inc./Consolidation Coal Co.	Velva	Undeveloped	1	M 5896*	5/1/71	40	Ward
Geo Resources Exploration, Inc./--	Nelson Pit	Undeveloped	1	M065329	12/1/64	320	Williams
Montana-Dakota Utilities/Knife River Coal Mining Co.	New Leipzig	Undeveloped	2	M437 M438	3/1/69 3/1/69	640 2872 3512	Hettinger & Grant
North American Coal Corp. Coteau Properties, Inc.	--	Undeveloped	1	M163	3/1/67	400	Mercer

*These leases were mined out before passage of the Surface Mine Control and Reclamation Act of 1977. However, they are [illegible] fied as undeveloped since no mine plan was submitted with the Office of Surface Mining.

OKLAHOMA

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Crane Co. = F&I Steel Corp.	Bokoshe	Approved	2	BLMC035068	10/1/53	1830	Flore
				BLMC035069	10/1/53	1640	
						3470	
Garland Coal and Mining Co./--	Stigler	Approved	1	BLMC030953	9/1/58	961	Haskell
Great National Corp./--	McCurtain No. 2	Approved	1	NM24005	12/1/79	140	Haskell
Northwest Industr: es, Inc./ Lone Star Steel Co.	Milton	Approved	2	BLMC018820	3/21/49	915	Le Flore
				NM059992	6/1/59	1680	
						2595	
Northwest Industries, Inc./ Lone Star Steel Co.	Starlight	Approved	1	BLMC021851	8/1/51	1500	Haskell
Standard Equipment, Inc./Mining Systems Corp.	Rees-Milton	Pending*	1	BLMI0 7902*	9/25/69	680	Le Flore
Armco Steel Corp./Evans Coal Co.	--	Undeveloped	4	BLMC022012	8/1/53	794	Haskell
				BLMC028799	5/1/56	640	
				BLMC032224	3/1/54	400	
				BLMI017564	9/7/68	1347	
						3181	
Armco Steel Corp./Evans Coal Co.	--	Undeveloped	2	NM023555	2/1/61	2560	Haskell
				NM023556	2/1/61	1687	
						4247	
Armco Steel Corp./Evans Coal Co.	--	Undeveloped	1	BLMC028369	7/1/52	1000	Le Flore
Armco Steel Corp./Evans Coal Co.	--	Undeveloped	1	BLMI017612	3/8/70	1869	Le Flore
Armco Steel Corp./Evans Coal Co.	--	Undeveloped	1	BLMC029794	4/1/56	2479	Pittsburg
Armco Steel Corp. Evans Coal Co.	--	Undeveloped	2	BLMC030584	9/1/56	2551	Pittsburg
				BLMC031611	10/1/56	2530	
						5081	

*This mine plan was submitted before passage of the Surface Mining Control and Reclamation Act of 1977 and has not been updated.

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OKLAHOMA (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
ASARCO, Inc. --	--	Undeve: oped	5	BLMC031985	12/1/57	1844	Le Flore
				BLMC032614	2/1/58	1000	
				NM033722	2/1/62	2552	
				NM033723	3/1/62	2520	
				NM036953	5/1/63	1160	
						9076	
Cameron Coal Co.	--	Undeveloped	u	BLMI017683	2/9/68	2560	Le Flore
				NM029891	5/1/62	960	
				NM029892	5/1/62	944	
--Pacola Co.				BLMI018108	9/25/69	960	
						5424	
Cari International Mining Corp./--	--	Undeveloped	1	NM0141015	7-1/62	360	Le Flore
Garland Coal and Mining Co./--	--	Undeveloped	1	BLMC022999	6 1/62	1385	Le Flore
Garland Coal and Mining Co. --	--	Undeveloped	6	BLMI018074	10/1/69	326	Le Flore
				NM025632	9 1/61	2266	
				NM033866	3-1/62	2048	
				NM034521	3 1/62	2544	
				NM0556624	1'/1/70	4375	
				NM0557450	9 1/65	880	
						12439	
General Dynamics Corp./Freeman United Coal Mining Co.	--	Undeveloped	1	NM536361	6/ /64	561	Le Flore
Hardy Hall	--	Undeveloped	1	BLMC027239	8/4/53	880	Haskell
Hardy Hall/--	--	Undeveloped	1	BLMC031135	5/1/56	1180	Haskell
Midwest Min: ng Corp. --	--	Undeveloped	1	NM0161332	12/1/61	2557	Le Flore
Northwest Industries, Inc./ Lone Star Steel Co.	--	Undeveloped	1	NM050405	12/1/59	1116	Le Flore
Northwest Industries, Inc./ Lone Star Steel Co.	--	Undeveloped	2	BLMC018125	9/1/50	2560	Pittsburg
				NM050406	12/1/59	2400	
						4960	

OKLAHOMA continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Northwest Industries, Inc./ Lone Star Steel Co.	--	Undeveloped	1	NM059996	4/1/60	719	Pittsburg
Petroleum International, Inc./--	--	Undeveloped	1	NM3·74	5/1/68	2840	Coal
Petroleum International, Inc./--	--	Undeveloped		NM957	9/1/67	3342	Haskell

UTAH - Uinta Region

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
American Electric Power Co./Franklin Real Estate Co.	Braztah No. 3,5,6&7	Approved	11	U058184	6/17/21	694	Carbon
				SL071737	9/1/50	1960	
				U25484	6/17/21	634	
				U019524	6/1/57	645	
				U0148779	8/1/66	1240	
				U0146345	11/1/65	1160	
				SL046652	8/3/21	802	
				SL048442	11/21/30	2563	
				SL029093	6/17/21	1284	
				U25683	12/1/79	1173	
				U25485	9/1/50	543	
						12699	
Atlantic-Richfield Co./Beaver Creek Coal Co.	Gordon Creek No. 2	Approved	1	U8319	3/1/70	962	Carbon
Atlantic-Richfield Co./Beaver Creek Coal Co. --Intermountain Exploration, Inc.	Huntington Canyon No. 4 & 5	Approved	3	SL064903	1/24/46	160	Emery
				U33454	12/1/78	440	
				SL050641	12/6/38	160	
						760	
Bell, John L./--	Trail Mountain	Approved	1	U082996	7/1/62	80	Emery
California Portland Co. --	Soldier Canyon	Approved	1	SL051279	1/4/35	1548	Carbon
The Coastal Corp./Coastal States Energy Co.	Convulsion Canyon (SUFCO)	Approved	4	SL062583	9/11/41	2200	Sevier
				U062453	3/1/62	480	
				U0149084	3/1/66	240	
				U28297	1/1/79	2632	
						5552	
Getty Oil Co./Plateau Mining Co.	Star Point No. 1&2	Approved	4	U7949	9/4/23	1631	Carbon
				SL031286	9/1/70	240	
				U37045	4/1/80	698	
				U13097	5/1/74	1360	Emery
						3929	
Kaiser Steel Corp. --	Sunnyside No. 1,2&3	Approved	2	SL062966	11/12/43	1367	Carbon
				U32083	3/1/79	476	
						1843	

UTAH - Uinta Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Quaker State Oil Refining Co./ Kanawha & Hocking Coal & Coke Co.	Belina No. &2	Approved	3	U0 7354*	9/1/56	1028	Emery
--McKinnon, Armeda/--				U044076**	9/1/65	2368	
--McKinnon Marital Trust/--				U020305***	9/1/56	1439	Carbon
						(1346 adj.)	
Quaker State Oil Refining Co./Kanawha & Hocking Coal & Coke Co.	Skyl ne	Approved	5	U073120	2/1/64	557	Carbon
--McKinnon Marital Trust/--				U0142235	10/1/64	520	Carbon
				U0147570	5/1/66	2093	Emery
				U020305***	9/1/56	1439	
--McKinnon, Armeda/--				U044076**	9/1/65	2368	
						(6335 adj.)	
Sharon Steel Corp./U.S. Fuel Co.	Hiawatha	Approved	3	SL025431	2/8/23	2370	Emery
				SL069985	11/1/49	2356	
				U026583	2/1/61	1000	
						5726	
Utah Power & Light Co./--	Des-Bee-Dove	Approved	3	U02664	1/1/57		Emery
				SL050133	8/1/33		
				SL066116	6/1/55		
Utah Power & Light Co./--	Deer Creek-Wilberg	Approved	9	U1358	8/1/67	320	
				SL064607	10/4/46	614	
				SL064900	2/3/45	160	
--Cooperative Security Corp./--				U040151	1/3/62	1720	Emery
				U083066	1/3/61	1285	
				U044025	1/8/60	40	
--McKinnon Marital Trust/--				U084923	8/1/64	2252	
				U084924	8/1/64	1211	
				SL070645	4/1/52	2560	
						1362	
U.S. Steel Corp./--	Geneva	Approved	2	SL046612	4/2/29		Carbon
				SL066145	6/19/46		

*Lease U017354 is also in the pending O'Connor mine plan.

**Approximately 337 acres of lease U04476 is in the Belina Mine; the remainder is in the approved Skyline mine plan a the pending O'Connor mine plan.

***About 960 acres of lease U020305 is shared by Belina Mine and the pending O'Connor Mine; the remaining lease acres are in the Skyline Mine.

UTAH — Uinta Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
AMCA Resources, Inc./AMCA Coal Leasing, Inc.	Pinnacle	Pending	3	SL027304 SL063058 U010581	9/1/25 8/3/42 2/1/56	120 240 1682 2042	Carbon
Inc. idation Coal Co.	Emery Deep	Pending	1	U5287	7/ /70	720	Emery
Energy Reserves Group, Inc./--	Skumpah	Pending	1	U0141177	3/1/67	2504	Sevier
Mountain States Resource Corp./--	Ute No. 1&2	Pending	1	U5135	5/1/77	8824	Sevier
Pacific Gas & Electric Co. Eureka Energy Co.	Sage Point-Dugout Canyon	Pending	5	U07746 U089096 U092147 U0144820 U07064	6/3/57 7/1/62 12/1/62 9/1/66 1/1/57		Carbon
Quaker State Oil Refining Co./Kanawha & Hocking Coal & Coke Co. --McKinnon, Armeda/-- --McKinnon Marital Trust/--		Pending	u	U067498 U017354* U044076** U020305**	1/1/62 9/1/56 9/1/65 9/1/56	502 1028 2368 1439 (944 adj.)	Carbon
U.S. Steel Corp./--	B Canyon	Pending	1	SL068754	6/ /51	2571	Carbon
Wasatch Coal Co./--	C and W No. 1	Pending	1	SL063011	1 /28/4	280	Carbon
Atlantic Richfield Co./Beaver Creek Coal Co.	—	Undeveloped	1	U020641	5/ /61	1909	Emery
Carbon ry Bank/--		Undeveloped	3	SL063720 U024814 U08606	12/17/42 1/1/58 10/1/53	200 37 40 277	Carbon
Carroll County Coal Co./--	—	Undeveloped		U7653	9/1/70	412	Emery

*Lease U017354 is also in the approved Belina Mine (see preceding page).

**Leases U044076 and U020305 are shared with the approved Belina and Skyline mines (see preceding page)

UTAH - Uinta Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Conoco, Inc./Consolidation Coal Co. and Gulf Oil Corp./Kemmerer Coal Co.	--	Undeveloped	9	U073040	6/1/62	2542	Emery
				U073041	6/1/62	2558	
				U0101213	6/1/65	2162	Sevier
				U0101214	6/1/65	2314	
				U0101215	6/1/65	856	
				U0101217	6/1/65	640	
				U0101218	6/1/65	1880	
				U090231	11/1/62	2497	
				U073039	6/1/62	2577	Emery
						20603	
COP Coal Development, Inc./--	--	Undeveloped	1	U024318	5/1/58	80	Emery
COP Coal Development, Inc./--	--	Undeveloped	1	U024316	5/1/58	1400	Emery
The Coastal Corp./Coastal States Energy Co.	--	Undeveloped	1	U053995	3/1/62	169	Sevier
Energy Reserves Group, Inc --	--	Undeveloped	3	U0141171	3/1/67	1825	Sevier
				U0141176	3/1/67	1544	
				U0141178	3/1/67	1976	
						5345	
Gent's Flying Enterprises --	--	Undeveloped	1	SL050655	11/17/3[illegible]	80	Emery
s Flying Enterprises/--	Tip Top	Undeveloped	1	SL062648	1/3/41	80	Emery
Kaiser Steel Corp. --	--	Undeveloped	2	U02785	7/1/52	2360	Carbon
				U039706	7/1/60	2559	
						4919	
Kaiser Steel Corp. --	--	Undeveloped	6	SL066490	12/31/47	2440	Emery
				SL069291	4/1/50	600	
				U0126947	12/1/63	1992	
				U0126948	12/1/63	2523	
				U014217	2/1/55	456	
				U014218	2/1/55	320	
						8331	

UTAH - Uinta Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Kingston, Charles/--	--	Undeveloped		U022918	4/1/58	120	Emery
McKinnon Marital Trust/--	--	Undeveloped	1	SL050862	8/5/37	280	Emery
Nevada Power Co./Nevada Electric Investment Co.	--	Undeveloped	2	U020668	5/1/58	627	Emery
				U38727	5/1/58	740	
						1367	
Northwest Energy Corp./Northwest Carbon Co.	--	Undeveloped	1	U46484	5/1/58	400	Emery
Pacific Gas & Electric Co./Eureka Energy Co.	--	Undeveloped	1	U05067	6/1/52	320	Carbon
Quaker State Oil Refining Co./Kanawha & Hocking Coal & Coke Co.	Utah No. 2	Undeveloped	1	SL062605	3/17/39	1053	Carbon
Smith-Holladay and Associates, Ltd/--	--	Undeveloped	1	U2810	10/1/67	80	Emery
Utah Power & Light Co./--	--	Undeveloped	5	SL051221	8/1/33	80	Emery
				U014275	10/1/55	80	
				U024317	5/1/58	400	
				U024319	5/1/60	1040	
				U06039	5/1/53	1360	
						2960	
Wilberg, Eliza and Lloyd --	--	Undeveloped	1	SL036407	9/10/26	80	

UTAH — Southwestern Region

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Arizona Public Serice Co./Resources Co.; San Diego Gas & Electric Co./ New Albion Resources Co.; and Southern California Edison Co./ Mono Power Co.	Kaiparowits No. 1-5	Pending	21	U087805	11/1/65	2064	Kane
				U087806	11/1/65	1945	
				U087807	11/1/65	1920	
				U087828	11/1/65	2560	
				U087833	11/1/65	2518	
				U087834	11/1/65	2560	
				U087835	11/1/65	1920	
				U087836	11/1/65	640	
				U092138	11/1/65	1891	
				U092139	11/1/65	1935	
				U092140	11/1/65	2022	
				U092141	11/1/65	1972	
				U092142	11/1/65	1750	
				U096486	11/1/65	640	
				U096494	11/1/65	2560	
				U096495	11/1/65	2560	
				U096496	11/1/65	2560	
				U096497	11/1/65	2560	
				U096508	4/1/66	658	
				U096509	11/1/65	1479	
				U0101142	4/1/67	1562	
						40276	
The El Paso Co. El Paso Energy Resources Co.	Red & Blue	Pending	5	U0115791	7/1/67	2560	Kane
				U0115792	10/1/67	1280	
				U0115793	7/1/67	1280	
				U0115833	10/1/67	640	
				U0130986	10/1/67	2562	
				U0130988	7/1/67	1907	
				U0130989	10/1/67	2560	
				U0136512	10/1/67	1279	
				U0140836	10/1/67	2557	
				U0140837	10/1/67	2553	
				U01408535	10/1/67	1920	
				U0130985	11/1/68	2560	
				U24427	3/1/67	1280	
				U27835	11/1/65	640	
				U083005	8/1/64	640	
						26218	

UTAH - Southwestern Region (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
General Electric Co./Utah International, Inc.	Alton	Pending	28	U0105404	6/1/65	1529	Kane
				U0115938	6/1/65	1721	
				U0122579	5/1/68	1120	
				U0122582	11/1/68	582	
				U0122583	11/1/68	320	
				U0122584	11/1/68	320	
				U0122623	4/1/66	280	
				U0122647	11/1/68	600	
				U0122649	11/1/68	840	
				U0122650	11/1/68	1600	
				U0122651	11/1/68	1080	
				U0122652	11/1/68	80	
				U0122675	11/1/68	80	
				U0124768	11/1/68	200	
				U0126916	11/1/68	320	
				U0140770	1/1/65	519	
				U0147999	5/1/65	320	
				U0149582	9/1/66	560	
				U098774	6/1/65	2488	
				U098775	6/1/66	1599	
--Nevada Power Co./Nevada Electric Investment Co.				SL058575	10/11/36	156	
				SL064507	11/1/44	320	
				U0101153	5/1/63	1000	
				U060745	11/1/61	2993	
				U060746	11/1/61	2324	
				U065012	11/1/61	755	
				U083072	7/1/62	1040	
				U098705	5/1/63	2287	
						26533	
Conoco, Inc./Consolidation Coal Co.	--	Undeveloped	0	U0:03107	9/1/67	2560	Kane
				U0103109	9/1/67	2557	
				U0103129	9/1/67	2560	
				U0103130	9/1/67	2554	
				U0105418	9/1/67	2560	
				U0149373	1/1/69	2560	
				U098783	5/1/67	2541	
				U098784	5/1/67	2538	
				U098785	5/1/67	2543	
				U098787	5/1/67	2560	
						25533	

UTAH - Southwestern Region (cont nued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Denton, Charles and Fulton, Caesar/--	--	Undeveloped	1	SL071561	3/1/51	80	Garfield
The El Paso Co./El Paso Natural Gas Co.	--	Undeveloped	1	U083000	12/1/64	1440	Kane
Frandsen, George/--	--	Undeveloped	1	SL048223	4/5/30	120	Garfield
Frandsen, George/--	--	Undeveloped	1	SL050638	5/10/41	40	Garfield
Hiko Bell Oil & Mining Co./--	South Nipple Butte	Undeveloped	3	U0118366	11/1/65	1920	Kane
				U0120794	3/1/66	1920	
				U0146654	12/1/65	2560	
						6400	
King Cannel Coal Co./--		Undeveloped	1	SL050619	6/1/38	240	Kane
Peabody Holding Co./Peabody Coal Co.	--	Undeveloped	9	U0103108	3/1/67	2560	Kane
				U0103131	4/1/67	2560	
				U0103132	4/1/67	1272	
				U0103133	4/1/67	1273	
				U0115656	11/1/67	2560	
				U0115657	11/1/67	2560	
				U096476	3/1/67	2552	
				U096477	3/1/67	1277	
				U098786	3/1/67	2550	
						19164	
Peabody Holding Co./Peabody Coal Co.		Undeveloped	[illegible]	U0101140	4/1/67	1600	Kane
				U0101141	4/1/67	1760	
				U0113254	8/1/67	160	
						3520	
Rasmussen, A. --	--	Undeveloped	1	SL049042	8/14/37	40	Kane
West S.H. --	-	Undeveloped	1	U0103141	9/1/67	961	Kane

WYOMING - Powder River Basin

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Amax, Inc. Ama Co.	Eagle Butte	Approved	1	W0313773	9/1/65	3520	Campbell
Amax, Inc./Amax Coal Co.	Belle Ayr	Approved	2	W0317682 W72282	9/1/65 9/1/80	2360 41 2401	Campbell
Atlantic-Richfield Co./Thunder Basin Coal Co.	Black Thunder	Approved	2	W2313 W36094	12/1/66 12/1/66	5844 40 5884	Campbell
Atlantic-Richfield Co./--	Coal Creek	Approved	1	W3446	11/1/67	5806	Campbell
Black Hi: ls Power & Light Co./ Wyodak Resources Development Co.	Wyodak	Approved	3	W0111833 W0313666 W073289	4/1/61 10/1/65 5/1/59	80 1560 240 1880	Campbell
Exxon Corp./The Carter Mining Co.	Cabal: o	Approved	2	W3397 W49644	12/1/67 9/1/65	5280 80 5360	Campbell
Exxon Corp./The Carter Mining Co.	Rawhide	Approved	1	W5036	12/1/67	5697	Campbell
Kerr-McGee Corp./Kerr-McGee Co.	Jacobs Ranch	Approved	2	W23928 W24710	9/1/70 9/1/70	4192 160 4352	Campbell
Mobil Oil Corp./--	Rojo Caballos	Approved	2	W23929 W58112	2/1/71 2/1/71	3119 840 3959	Campbell
Pacific we & Light Co./--	Dave Johnston	Approved	6	C054769 W0244167 W0312918 W038597 W038602 W041355	5/31/33 6/1/63 6/1/65 8/1/58 6/1/56 7/2/56	120 1803 3779 1400 2000 560 9662	Converse
Shell Oil Corp./--	Buckskin	Approved	1	W0325878	11/1/67	599	Campbell
The Sun Co./Sunoco Energy Deve: opment Co.	Cordero	Approved	1	W8385	3/1/71	6560	Campbell

WYOMING - Powder River Basin cont

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Exxon Corp./The Carter Mining Co.	South Rawhide	Pending	1	W5035	12/1/67	4782	Campbell
Pacific Power & Light Co./ Resource Development Co.	Antelope	Pending	3	W0321780 W0322255 B031719	12/1/66 12/1/66 11/22/32	2908 1869 40 4817	Converse
Richard Bass Trust/--	Bass	Undeveloped	1	W961	12/1/67	20701	Sheridan
Belco Petroleum Corp./--	Belco	Undeveloped	1	W0322794	1/1/70	4551	Johnson
Black Hills Power & Light Co./Wyodak Resources Development Co.	Blue Diamond	Undeveloped	1	B037423	2/22/44	40	Campbell
Cities Service Corp./--	Dry Fork	Undeveloped	3	W0271199 W0271200 W0271201	12/1/67 12/1/67 12/1/67	640 760 2180 3580	Campbell
Gulf Oil Corp./--	Gulf 1&2 (Arvada)	Undeveloped	3	W0236507 W0236621 W0240559	3/1/65 6/1/63 9/1/63	195 2551 1620 4366	Sheridan
Gulf Oil Corp./--	Gulf 3	Undeveloped	1	W0256663	3/1/65	756	Campbell
Gulf Oil Corp./--	Wildcat	Undeveloped	1	W02205 6	3/1/65	1571	Campbell
Kerr-McGee Corp./Kerr-McGee Coal Corp.	East Gillette Federal	Undeveloped	3	W0311810 W0312311 W0313668	1/1/70 7/1/65 10/1/65	1263 880 2200 4343	Campbell
Pacific Power & Light Co. --	Phillips Creek (1)	Undeveloped	4	W0136194 W0136195 W0136196 W0324701	6/1/61 6/1/61 6/1/61 2/1/70	322 1477 1560 680 4039	Converse

WYOMING - Powder River Basin (continued)

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Pacific Power & Light Co./--	Phillips Creek (2)	Undeveloped	1	W0310712	12/1/66	40	Converse
Panhandle Eastern Pipeline Co. and Peabody Holding Co./North Antelope Coal Co.	N. Antelope	Undeveloped	1	W60231	12/1/66	320	Campbell
Peabody Holding Co./Peabody Coal Co	East Wyodak	Undeveloped	1	W0313667	10/1/65	2560	Campbell
Holding Co./Peabody Coal Co.	Rochelle	Undeveloped	2	W0321779	12/1/66	8781	Campbell
				W37829	12/1/66	40	
						8821	
Peter Kiewit Sons, Inc./Big Horn Coal Co.	Armstrong	Undeveloped	1	B025369	5/17/30	80	Sheridan
Shell Oil Corp./--	North Rochelle	Undeveloped	1	W71692	12/1/66	2000	Campbell
Texaco, Inc./--	Lake DeSmet	Undeveloped	5	W030052	11/1/59	2203	Johnson
				W046349	10/1/61	160	
				W051959	8/1/57	320	
				W030009	12/1/55	1913	
				W0321120	5/1/66	4821	
						9417	

WYOMING - Rock Springs

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Idaho Power Co. and Pacific Power & Light Co./Bridger Coal Co.	Jim Br	Approved	3	W031355[illegible] W2727 W2728	1/1/68 10/1/68 10/1/69	4276 2880 1280 8436	Sweetwater
Ideal Basic Industries, Inc. and Union Pacific Corp./Stansbury Coal Co.	Stansbury	Approved	1	W 2793	6/1/70	1645	Sweetwater
Peter Kiewit Sons, Inc. and Union Pacific Corp/Black Butte Coal Co.	Black Butte	Approved	1	W6266	4/1/76	14902	Sweetwater
Monsanto Co./Sweetwater Resources, Inc.	Rainbow No. [illegible]	Undeveloped	1	[illegible] 5 55	9/19/27	1752	Sweetwater
Pacific Power & Light Co./Resource Deve[illegible]opment Co.	Cherokee	Undeveloped	4	W0312917 W092141 W0313559 W092140	4/1/67 7/1/62 6/1/65 7/1/62	480 2480 640 671 4271	Carbon & Sweetwater
Peabody Holding Co./Peabody Coal Co.	Boar's Tusk	Undeveloped	2	W0220486 W3438	4/1/67 3/1/70	1840 640 2480	Sweetwater
The Sun Co./Sunoco Energy Development Co.	Long Canyon	Undeveloped		W0313201	7/1/68	14680	Sweetwater

WYOMING - Hanna Basin

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Ashland Oil & Hunt Interests/ Ark Land Co.	Seminoe No. 1	Approved		W16466	2/1/71	6315	Carbon
Ashland Oil & Hunt Interests/ Ark Land Co.	Seminoe No. 2	Approved	7	C033800	10/8/24	398	Carbon
				C078051	5/1/51	160	
				W0146199	1/1/64	640	
				W054727	11/1/61	1264	
				W054737	11/1/61	320	
				W31258	5/1/51	160	
				W49338	8/1/80	735	
						3677	
Ashland Oil & Hunt Interests and Union Pacific Corp./Medicine Bow Coal Co.	Medicine Bow	Approved	2	W42554	2/1/71	1280	Carbon
				W58095	10/1/80	1288	
						2568	
Ashland Oil & Hunt Interests/ Ark Land Co.	Carbon No. 1	Approved	3	C057086*	4/5/35	—*	Carbon
				W0150169	1/1/64	640	
				W054728	1/1/61	640	
						1280	
Iowa Public Service Co./Energy Development Co.	Vanguard No. 2	Approved	1	W 6465	9/1/69	8683	Carbon
Peter Kiewit Sons, Inc./Rosebud Coal Sales	Rosebud	Approved	2	C057086	4/5/35	1273	Carbon
				W48330	2/1/80	130	
						1408	
Ashland Oil & Hunt Interests/ Ark Land Co.	Hanna South	Undeveloped	1	W25406	1/1/71	640	Carbon

*This lease is being mined by Rosebud Coal Sales and by Carbon County Sales as operator for Ark Land Co. Rosebud is mining the surface reserves; Carbon County is mining the underground reserves. Total acreage for this lease is entered under Peter Kiewit Sons, Inc./Rosebud Coal Sales.

WYOMING - Kemmerer Field and Bighorn Basin

LESSEE: PARENT/SUBSIDIARY	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	DATE	ACRES	COUNTY
Kemmerer Field							
FMC Corp./--	Skull Point	Approved	2	W061421 W061422	3/1/63 3/1/63	1280 1921 3201	Lincoln
Gulf Oil Corp./Kemmerer Coal Co.	Elkol-Sorenson	Approved	1	W055246	3/1/58	2401	Lincoln
Peter Kiewit Sons, Inc. and Union Pacific Corp./Cumberland Coal Co.	South Haystack	Pending	1	W060241	3/1/63	1408	Uinta
Cravat Coal Co./Conotton Land Co.	Cottonwood	Undeveloped	1	E018804	3/28/38	160	Sublette
Cravat Coal Co./Conotton Land Co.	Deadman	Undeveloped	1	W023373	2/1/58	240	Lincoln
Granite Creek Coal & Uranium Co. --	Granite Creek	Undeveloped	1	E019039	3/11/41	280	Teton
Gulf Oil Corp./Kemmerer Coal Co.	North Block	Undeveloped	4	W075207* W0294513 W056471 W060274	1/2/59 7/1/64 4/1/62 2/1/63	714 519 960 745 2938	Lincoln
Gulf Oil Corp./Kemmerer Coal Co.	North-North Block	Undeveloped	1	W075206	1/2/59	1247	Lincoln
Bighorn Basin							
Montana Power Co./Northwestern Resources Co.	Kowlok	Undeveloped	1	C069111	12/1/45	120	Hot Springs
Phelps Dodge Corp./Western Nuclear, Inc.	Western Nuclear	Undeveloped	1	W022978	8/1/54	80	Hot Springs

*This lease is contiguous to both the approved Elkol-Sorenson lease and North Block. However, present plans are to mine the lease as part of North Block.

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LEASEHOLDING SUBSIDIARY	LISTED UNDER PERENT	JOINTLY OWNED BY:
Amax Coal Co.	Amax, Inc.	--
Amca Coal Leasing, Inc.	Amca Resources	--
Anchor Coal Co.	St. Joe Minerals Corp.	--
Ark Land Co.	Ashland Oil & Hunt Interests	--
Beaver Creek Coal Co.	Atlantic-Richfleld Co.	--
Belden Enterprises	Eastern Gas & Fuel Assoc. (50 percent)	NICOR, Inc. (50 percent)
Big Horn Coal Co.	Peter Kiewit Sons, Inc.	--
Bridger Coal Co.	Idaho Power Co. (33.3 percent)	Pacific Power & Light Co. (66.6 percent)
Black Butte Coal Co.	Peter Kiewit Sons, Inc. (50 percent)	Union Pacific Corp. (50 percent)
Cambridge Coal Co.	General Exploration, Inc.	--
The Carter Mining Co.	Exxon Corp.	--
CF&I Steel Co.	Crane Co.	--
Coastal States Energy Co.	The Coastal Corp.	—
Colorado Westmoreland Co.	Westmoreland Coal Co.	--
Colowyo Coal Co.	Hanna Mining Corp. (50 percent)	W.R. Grace & Co. (50 percent)
Conotton Land Co.	Cravat Coal Co.	--
Consolidation Coal Co.	Conoco, Inc.	--
Coteau Properties, Inc.	North American Coal Co.	--
Cumberland Coal Co.	Peter Kiewit Sons, Inc. (50 percent)	Union Pacific Corp. (50 percent)
Eastern Associated Properties Corp.	Eastern Gas & Fuel Assoc.	--
El Paso Energy Resources Co.	The El Paso Co.	—
El Paso Natural Gas Co.	The El Paso Co.	--
Empire Energy Corp.	Standard Oil of Indiana Co.	--
Energy Development Co.	Iowa Public Service Co.	--
Energy Fuels Co.	Getty oil co.	--
Eureka Energy Co.	Pacific Gas & Electric Co.	--
Evans coal coo	Armco Steel Corp.	--
Falkirk Mining Co.	North American Coal Corp.	--
Fannin Square Corp.	Texas Eastern Transmission Corp.	--
Franklin Real Estate Co.	American Electric Power Co.	--
Freeman United Coal Mining Co.	General Dynamics Corp.	--
GEX Colorado	General Exploration, Inc.	--
Kanawha & Hocking Coal & Coke Co.	Quaker State Oil Refining Co.	--
Kemmerer Coal Co.	Gulf Oil Corp.	--
Kerr Coal Co.	Getty oil Corp.	—
Kerr-McGee Coal Corp.	Kerr-McGee Corp.	--
Knife River Coal Mining Co.	Montana-Dakota Utilities	--
Lone Star Steel Co.	Northwest Industries, Inc.	--
Materials Service Co.	General Dynamics Corp.	--
Medicine Bow Coal Co.	Ashland Oil & Hunt Interests (50 percent)	Union Pacific Corp. (50 percent)
Midcontinent Limestone Co.	Midcontinent Resources, Inc.	—
Mining Systems Corps.	Standard Equipment, Inc.	--
Mono Power Co.	Southern California Edison Co.	--

Nevada Electric Investment co.	Nevada Power Co.	
New Albion Resources Co.	San Diego Gas & Electric Co.	- -
North Antelope Coal Co.	Panhandle Eastern Pipeline Co. (50 percent)	Peabody Holding Co. (50 percent)
Northern Minerals Corp.	Internorth Corp.	
Northwest Carbon Co.	Northwest Energy Corp.	- -
Northwestern Resources Co.	Montana Power Co.	
Peabody Coal Co.	Peabody Holding Co.	- -
Plateau Mining Co.	Getty Oil co.	—
Resource Development Co.	Pacific Power & Light Co.	- -
Resources Co.	Arizona Public Service Co.	- -
Rosebud Coal Sales	Peter Kiewit Sons, Inc.	- -
Sheridan Enterprises, Inc.	Occidental Petroleum Corp.	- -
Spring Creek Coal Co.	Pacific Power & Light Co.	- -
Stansbury Coal Co.	Ideal Basic Industries (50 percent)	Union Pacific Corp. (50 percent)
Sunland Mining Corp.	Consolidated Gas & Oil Corp.	- -
Sunoco Energy Development Co.	The Sun Co.	- -
Sweetwater Resources, Inc.	Monsanto Co.	- -
Thunder Basin Coal Co.	Atlantic-Richfield Co.	—
U.S. Fuel Co.	Sharon Steel Corp.	. -
Utah International, Inc.	General Electric Co.	- -
Western Coal Co.	Public Service Co. of New Mexico (50 percent)	Tuscon Electric Co. (50 percent)
Western Energy Co.	Montana Power Co.	- -
Western Nuclear, Inc.	Phelps Dodge Corp.	- -
Western Slope Carbon, Inc.	Northwest Energy Corp.	- -
Wyodak Resources Development Co.	Black Hills Power & Light Co.	- -
Wyoming Fuels Co.	Kansas Nebraska Natural Gas Co.	

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
AMAX, Inc.							
AMAX Coal Co.	WY	Eagle Butte	A	1	W0313773	3520	
	WY	Belle Ayr	A	2	W0317682	2360	
					W72282	41	
AMCA Resources							
AMCA Coal Leasing, Inc.	CO	--	U	1	C030472	120	
	CO	-	U	1	D051376	250	
	UT	P: onac. e	P	3	SL027304	120	
					SL063058	240	
					U010581	1682	
American Colloid Co.	ND	American Colloid	U	1	M061025	80	
American Electric Power Co.							
Franklin Real Estate Co.	CO	Cardinal	U	1	C012894	634	
	UT	Braztah No. 3,5,6&7	A	11	U058184	694	
					SL071737	1960	
					U25484	634	
					U25485	543	
					U019524	645	
					U0148779	1240	
					U0146345	1160	
					SL046652	802	
					SL048442	2563	
					SL029093	1284	
					U25683	1173	
Ametex Corp.	NM	--	U	1	SF048323	120	
	NM	--	U	1	NM732	160	
	CO	Snowmass	P	2	C08172	2413	
					C08173	2469	

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Arizona Public Service Co.							
Resources Co. (33.3 percent)	UT	Kaiparowits No. 1-5	C&	21	U087805	2064	San Diego Gas & Electric Co./New Albion Resources Co. and Southern California Edison Co./Mono Power Co. each hold 33.3 percent interest in these leases.
					U087806	1945	
					U087807	1920	
					U087828	2560	
					U087833	2518	
					U087834	2560	
					U087835	1920	
					U087836	640	
					U092138	1891	
					U092139	1935	
					U092140	2022	
					U092141	1972	
					U092142	1750	
					U096486	640	
					U096494	2560	
					U096495	2560	
					U096496	2560	
					U096497	2560	
					U096508	658	
					U096509	1479	
					U0101142	961	
Armco Steel Corp.							
Evans Coal Co.	OK	--	U	4	BLMC022012	794	
					BLMC028799	640	
					BLMC032224	400	
					BLMI017564	1347	
	OK	-	U	2	NM023555	2560	
					NM023556	1687	
	OK	—	U	1	BLMC028369	1000	
	OK	–	U	1	BLMI017612	1869	
	OK	-	U	1	BLMC029794	2479	

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PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	
Armco Steel Corp.							
Evans Coal Co. (continued)	OK	--	U	2	BLMC030584	2551	
					BLMC031611	2530	
ASARCO, Inc.							
	OK	-	U	5	BLMC031985	1844	
					BLMC032614	1000	
					NM033722	2552	
					NM033723	2520	
					NM036953	1160	
Ashland Oil & Hunt Interests							
Ark Land Co.	WY	Seminoe No. 1	A	1	W16466	6315	
	WY	Seminoe No. 2	A	7	C033800	398	
					C078051	160	
					W0146199	640	
					W054727	1264	
					W054737	320	
					W31258	160	
					W49338	735	
	WY	Carbon No. 1	A	3	C057086*	--	
					W0150169	640	
					W054728	640	
	WY	Hanna South	U	1	W25406	640	
Medicine Bow Coal Co. (50 percent)	WY	Medicine Bow	A	2	W42554	1280	Union Pacific Corp. holds 50 percent interest in Medicine Bow Coal Co.
					W58095	1288	
Atlantic-Richfield Co.							
	CO	Mt. Gunnison No. 1	P	3	C011792	1243	
					C1362	4836	
	CO	Bear	A & P		D044569**	1340	
	WY	Coal Creek	A	1	W344	5806	

*This lease is being mined by Rosebud Coal Sales and by Carbon County Sales as operator for Ark Land Co. Rosebud is mining the surface reserves; Carbon County is mining the underground reserves. Total acreage for this lease is entered under Peter Kiewit Sons, Inc./Rosebud Coal Sales.

**This lease is in both Mt. Gunnison's pending mine plan and Bear Mine's approved mine plan.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Atlantic-Richfield Co. (continued)							
Beaver Creek Coal Co.	UT	Gordon Creek No. 2	A		U8319	962	
	UT	Huntington Canyon No. 4 & 5	A	2	U33454 SL064903	440 160	There are three Federal leases in this mine. The third is held by Intermountain Exploration, Inc.
	UT	-	U		U02064	·909	
Thunder Basin Coal Co.	WY	Black Thunder	A	2	W2313 W36094	5844 40	
Bass, Richard (Trust)	WY	Bass	U	1	W961	20701	
Baukol-Noonan, Inc.	ND	Center	P	1	M043848	2325	
Belco Petroleum Corp.	WY	Belco	U	1	W0322794	455	
Bell, John L.	UT	Trail Mountain	A	1	U082996	80	
Black Hills Power & Light Co.							
Wyodak Resources Development Co.	WY	Wyodak	A	3	W0111833 W0313666 W073289	80 1560 240	
	WY	Blue Diamond	U	1	B037423	40	
Bonsness, Leroy	ND	Leroy Bonsness	U	1	BLMO 8322*	80	
Bugni, A., T. and R.	MT	Bugni	U	1	GF082523	80	
California Portland Cement Co.	UT	Soldier Canyon	A	1	SL05 279	·548	
Cameron Coal Co.	OK	--	U	3	BLMI017683 NM029891 NM029892	2560 960 944	There are four Federal leases in this lease block. The fourth is held by The Pacola Co.
Carbon Emery Bank	UT	--	U	3	SL063720 U024814 U08606	200 37 40	

*This lease was mined out before passage of the Surface Mine Control and Reclamation Act of 1977. However, it is classified as undeveloped since no mine plan was submitted with the Office of Surface Mining.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	
Cari International Mining Corp.	OK	-	U	1	NM0141015	360	
Carroll County Coal Co.	UT	-	U	1	U7653	412	
Chapman, Russell W. and Riebold, Paul	CO	-	U	1	C028875	1675	
Cimarron Coal Co.	NM	La Plata	U	1	NM0315559	2044	
Cities Service Corp.							
	WY	Dry Fork	U	3	W0271199 W0271200 W0271201	640 760 2180	
The Coastal Corp.							
Coastal States Energy Co.	UT	Convulsion Canyon (SUFCO)	A	3	SL062583 U062453 U0149084 U28297	2200 480 290 2632	
	UT	-	U	1	U053995	169	
Conoco, Inc.							
Consolidation Coal Co.	CO	--	U	2	C093714 C093715	571 760	
	CO	--	U	1	C1546	1097	
	CO	--	U	1	C245	226	
	CO	--	U	2	C093713 C093716	2518 2061	
50 percent)	CO	--	U	1	C0105299	560	Gulf Oil Corp./Kemmerer Coal Co. holds 50 percent interest in these three leases.
(50 percent	CO		U	1	C0105300	1680	
50 percent)	CO		U	1	C0123177	1707	

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Conoco, Inc.							
Consolidation Coal Co. (continued)							
	UT	Emery Deep	P	1	U5287	720	
	UT	--	U	[illegible]	U0103107	2560	
					U0103109	2557	
					U0103129	2560	
					U0103130	2554	
					U0105418	2560	
					U0149373	2560	
					U098783	2541	
					U098784	2538	
					U098785	2543	
					U098787	2560	
50 percent	UT		U	9	U073039	2577	Gulf Oil Corp./Kemmerer Coal Co. holds 50 percent interest in these nine leases.
					U073040	2542	
					U073041	2558	
					U0101213	2162	
					U0101214	2314	
					U0101215	856	
					U0101217	640	
					U0101218	1880	
					U090231	2497	
	MT	CX Ranch	U		M46292	674	
	ND	Glenharold	A	3	M070203	477	
					M11269	260	
					M121209*	1668	
	ND	Renner s Cove	U	1	M37829	322	
	ND	Velva	U	1	M15896**	40	

*This lease is in a pending mine plan; however, it has been grouped with leases in approved mine plans for the purpose of OTA's analysis because of its association with the two leases in the Glenharold mine plan.

**This lease was mined out before passage of the Surface Mining Control and Reclamation Act of 1977. However, it is classified as undeveloped since no mine plan was submitted with the Office of Surface Mining.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Consolidated Gas & Oil Corp.							
Sunland Mining Corp.	CO	Apex No. 2	A	2	C0127592	80	
					D046544	160	
Cooperative Security Corp.	UT	Deer Creek-Wilberg	A	3	U040151	1720	There are nine Federal leases in this mine. Three are held by McKinnon Marital Trust; an additional three are held by Utah Power and Light Co.
					U044025	40	
					U083066	1285	
COP Coal Development, Inc.							
	UT	--	U	1	U024318	80	
	UT	--	U	1	U024316	1400	
Crane Co.							
CF&I Steel Co.							
	CO	--	U	1	C067	962	
	OK	Bokoshe	A	2	BLMC035068	1830	
					BLMC035069	1640	
Cravat Coal Co.							
Conotton Land Co.							
	WY	Cottonwoood	U	1	E018804	160	
	WY	Deadman	U	1	W023373	240	
Davis, Robert Lee	NM	--	U	1	SF074673	40	
Denton, Charles and Fulton, Caesar	UT	Shakespeare	U	1	SL071561	80	
Eastern Gas & Fuel Associates							
Eastern Associated Properties Corp. (50 percent)	NM	Black Lake	U	1	NM10931	1910	Texas Eastern Transmission Corp./Fannin Square Corp. holds 50 percent interest in this lease.
Belden Enterprises (50 percent)	CO	Colby Red Canyon	P	1	D036906	41	NICOR, Inc. holds 50 percent interest in Belden Enterprises.
Divide Coal Mining Co.	MT	Divide	A	1	M052647	80	

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
The El Paso Co.							
El Paso Energy Resources Co.	UT	Red & Blue	P	15	U0115791	2560	
					U0115792	1280	
					U0115793	1280	
					U0115833	640	
					U0130986	2562	
					U0130988	1907	
					U0130989	2560	
					U0136512	1279	
					U0140836	2557	
					U0140837	2553	
					U01408535	1920	
					U0130985	2560	
					U24427	1280	
					U27835	640	
					U083005	640	
El Paso Natural Gas Co.	UT	--	U		U083000	1440	
Energy Reserves Group, Inc.	UT	Skumpah	P		U0141177	2504	
	UT	--	U	3	U0141171	1825	
					U0141176	1544	
					U0141178	1976	
Exxon Corp.							
The Carter Mining Co.	WY	Rawhide	a		W5036	5697	
	WY	Caballo	A	2	W3397	5280	
					W49644	80	
	WY	South Rawhide	P		W5035	4782	
Fulton, Caesar*	— — — SEE FOOTNOTE — — —						

*Caesar, Fulton holds 50 percent interest in one lease. See leaseholding under Denton, Charles.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
FMC Corp.	WY	Skull Point	A	2	W061421	1280	
					W061422	1921	
Frandsen, George	UT	--	U	1	SL048223	120	
	UT	--	U	1	SL050638	40	
Garland Coal & Mining Co.	CO	Thompson Creek	U	1	C012765	498	
	OK	Stigler	A	1	BLMC030953	961	
	OK	--	U	1	BLMC022999	1385	
	OK	--	U	6	BLMI018074	326	
					NM025632	2266	
					NM033866	2048	
					NM034521	2544	
					NM0556624	4375	
					NM0557450	880	
General Dynamics Corp.							
Materials Service Co.	CO	Seneca 2 W	A	2	C081251	2519	There are three Federal leases in this mine. The third is held by Peabody Holding Co./Peabody Coal Co.
					C081258	2323	
Freeman United Coal Mining Co.	OK	-	U		NM536361	561	
General Electric Co.							
Utah International, Inc.							
	CO	Trapper	A	[illegible]	C25948	85	
					C07518	2566	
					C07519	1372	
					C079641	1352	
	CO	Green Valley	U	1	D055156	174	
	CO	--	U	1	C0123476	2252	
	CO	--	U	1	C813	160	

LESSEE Leaseholding (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
General Electric Co.							
Utah International, Inc. continued							
	UT	Alton	P	20	U0105404	1529	There are twenty-eight Federal leases in this mine. The other eight are held by Nevada Power Co./Nevada Electric Investment Co.
					U0115938	1721	
					U0122579	1120	
					U0122582	582	
					U0122583	320	
					U0122584	320	
					U0122623	280	
					U0122647	600	
					U0122649	840	
					U0122650	1600	
					U0122651	1080	
					U0122652	80	
					U0122675	80	
					U0124768	200	
					U0126916	320	
					U0140770	519	
					U0147999	320	
					U0149582	560	
					U098774	2488	
					U098775	1599	
General Exploration, Inc.							
GEX Colorado	CO	Cameo	A	1	C01538	2560	
Cambridge Coal Co.	CO	Roadside	A	1	C078049	810	
Gent's Flying Enterprises	UT	--	U	1	SL050655	80	
	UT	Tip Top	U	1	SL062648	80	
Geo Resources Exploration, Inc.	ND	Nelson Pit	U	1	M065329	320	
Getty Oil Corp.							
Kerr Coal Co.	CO	Marr	A	1	C22777	770	
Energy Fuels Co.	CO	Energy Fuels No. 1 & 2	A	7	C20900	420	
					C22644	1790	
					C22676	402	
					D052547	1145	
					C0128433	475	
					C081330	2215	
					C16284	263	

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Getty Oil Corp.							
Plateau Mining Co. (continued)	UT	Star Point 1 & 2	A	4	U7949	1631	
					SL031286	240	
					U13097	1360	
					U37045	698	
Granite Creek Coal & Uranium Co.	WY	Granite Creek	U	1	[illegible] 9039	280	
Great National Corp.	OK	McCurtain No. 2	A	1	NM24005	140	
Gulf Oil Corp.	WY	Gulf 1 & 2 (Arvada)	U	3	W0236507	195	
					W0236621	2551	
					W0240559	1620	
	WY	Gulf 3	U	1	W025663	756	
	WY	Wildcat	U	1	W0220516	1571	
	CO	Edna Strip	A	<	D033327	280	
					D041478	80	
					D053710	89	
	CO	Trout Creek	A&P		C021601*	827	
	CO	Paonia Farmer's	U	1	D036955	280	
	NM	McKinley	A	4	NM057349	2513	
					NM057348	2485	
					NM0554844	540	
					NM065466	2560	
Kemmerer Coal Co.***							
	WY	Elkol-Sorenson	A	1	W055246	2401	
	WY	North Block	U	4	W075207**	714	
					W0294513	519	
					M056471	960	
					W060274	745	
	WY	North-North Block	U	1	W075206	1247	

*This lease is in both the approved Edna Strip mine plan and the pending Trout Creek mine Plan.
**This lease is contiguous to both the approved Elkol-Sorenson lease and North Block. However, present plans are to mine the lease as part of North Block.
***Gulf Oil Corp./Kemmerer Coal Co. holds 50 percent interest in an additional 12 leases in four other lease blocks. See leaseholdings under Conoco, Inc./Consolidation Coal Co.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Gulf Oil Corp.							
Kemmerer Coal Co. continued	CO	Tongue Mesa	U	6	C0120073	2240	
					C0120078	2000	
					C0120079	2560	
					C0120080	1600	
					D038385	360	
					C0120077	1242	
	CO	Tongue Mesa	U	1	C0120076	2320	
Hall, Hardy	OK	-	U	1	BLMC027239	880	
	OK	-	U	1	BLMC031135	1180	
Hiko Bell Oil & Mining Co.	UT	South Nipple Butte	U	3	U0118366	1920	
					U0120794	1920	
					U0146654	2560	
Hanna Mining Corp.							
Colowyo Coal Co. (50 percent)	CO	Colowyo Strip	A	·	D034365	2545	W.R. Grace & Co. holds 50 percent interest in Colowyo Coal Co.
Idaho Power Co.							
Bridger Coal Co. (33.3 percent)	WY	Jim Bridger	A	3	W0313558	4276	Pacific Power and Light Co. holds 66.6 percent interest in Bridger Coal Co.
					W2727	2880	
					W2728	1280	
Ideal Basic Industries, Inc.	NM	La Ventana	P	5	NM0510466	2002	
					NM0510467	2433	
					NM0510468	2505	
					NM0555316	160	
					NM0555317	2206	
Stansbury Coal Co. (50 percent)	WY	Stansbury	a		W12793	1645	Union Pacific Corp. holds 50 percent interest in Stansbury Coal Co.
Ingraham, Floyd E.	NM	--	U	1	SF077115	160	
Intermountain Exploration, Inc.	UT	Huntington Canyon No. 4 & 5	A	1	SL050641	160	There are three Federal leases in this mine. The other two are held by Atlantic-Richfield Co./Beaver Creek Coal Co.

PARENT CO. Leaseholding Subisidary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	TE
Internorth Corp.							
Northern Minerals Corp.	CO	Meeker Area	A	5	C1545	896	
					C28358	886	
					C28359	1000	
					C076713	320	
					D044240	160	
Iowa Public Service Co.							
Energy Development Co.	WY	Vanguard No. 2	A	1	W16465	8683	
James Brothers Coal Co.	CO	Cottonwood Creek	P	1	C024889	2522	There are three Federal leases at this mine. One is held by Pitkin Iron Corp. The other is held jointly by Pitkin Iron Corp. and Richard & Kermit James
James, Kermit & Richard (66.6 percent)	CO	Cottonwood Creek	P	1	C024998	2551	Pitkin Iron Corp. holds 33.3 percent interest in this lease.
James, Ferne M. (estate)	CO	--	U	1	C064416	40	
Johnson, G. & A.	MT	Johnson	U	1	B028531	80	
Kaiser Steel Corp.	UT	Sunnyside No. 1,2&3	A	2	SL062966	1367	
					U32083	476	
	UT	--	U	6	SL066490	2440	
					SL069291	600	
					U0126947	1992	
					U0126948	2523	
					U014217	456	
					U014218	320	
	UT		U	2	U02785	2360	
					U039706	2559	
Kansas Nebraska Natural Gas Co.							
Wyoming Fuels Co.	CO	Canadian Strip	A	·	C27931	90	
	CO	--	U	·	D057166	173	
Kerr-McGee Corp.							
Kerr-McGee Coal Corp.	WY	Jacobs Ranch	A	2	W23928	4192	
					W24710	160	
	WY	East Gillette Fed.	U	3	W0311810	1263	
					W0312311	880	
					W0313668	2200	

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
King Cannel Coal Co.	UT	-	U	1	SL050619	240	
Kingston, Charles	UT	-	U	1	U022918	120	
Lombardi, Prosper	CO	Johnnie's	P	1	C23396	80	
Martinez, Albert	CO	-	U	1	P058043	40	
McKinnon, Armeda	UT	Belina No. 1 & 2, Skyline, and O'Connor	A&P	1	U044076*	2368	There are a total of seven Federal leases in these three mines: three are held by Quaker State Oil Refining Co. and three are held by McKinnon Marital Trust
McKinnon Marital Trust	UT	Deer Creek-Wi berg	A	3	SL070645 U084923 U084924	2560 2252 1211	There are nine Federal leases in this mine. Three are held by Cooperative Security Corp.; an additional three are held by Utah Power and Light Co.
	UT	Belina No. 1&2 Skyline and O'Connor	A	3	U020305** U0142235 U0147570	1439 520 2093	There are a total of seven Federal leases in these three mines. Three are owned by Quaker State Oil Refining Co. and one by Armeda McKinnon
	UT	--	U		SL050862	280	
Mid Continent Resources, Inc.	CO	Coal Basin	A	9	C0125457 C0115606 C011646 C0125456 C030345 C074632 C12640 C09004 C09005	1142 80 957 80 117 680 1529 1529 1365	
Mid Continent Limestone Co.	CO	Coal Canyon	P	3	C037277 C059420 C040389	1471 308 241	

*This lease is in the approved Belina & Skyline mine plan and the pending O'Connor mine plan.
**Approximately 960 acres of lease U020305 are shared by Belina Mine and the pending O'Connor Mine; the remaining lease acres are in the Skyline Mine.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES
Midwest Mining Corp.	OK	--	U		NM0161332	2557
Mobil Oil Corp.	WY	Rojo Caballos	A	2	W23929	3119
					W58112	840
Monsanto Co.						
Sweetwater Resources, Inc.	WY	Rainbow No. 8	U	1	E015155	1752
Montana-Dakota Utilities						
Knife River Coal Mining Co.	MT	Savage	A		M023207	960
	ND	Gascoyne	A		BLM019127	2872
	ND	South Beulah	A	2	M041765	1600
					M43083*	80
	ND	New Leipzig	U	2	M437	640
					M438	2872
Montana Power Co.						
Western Energy Co.	MT	Rosebud	A		B020989	1446
					M073109	5792
					M35734	480
					N34735	447
					N42381	62
Northwestern Resources Co.	WY	Kowlok	U	1	C069111	120
Mountain States Resource Corp.	UT	Ute No. & 2	P		U5135	8824
National King Coal, Inc.	CO	King Coal	A		P058300	60

*This lease, although not in a mine plan, is closely associated with the approved South Beulah lease. It has therefore been grouped with this lease for the purposes of OTA's analysis.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Nevada Power Co.							
Nevada Electric Investment Co.	UT	Alton	P	8	SL058575 SL064507 U0101153 U060745 U060746 U065012 U083072 U098705	156 320 1000 2993 2324 755 1040 2287	There are twenty-eight Federal leases in this mine. The other twenty are held by General Electric Co./Utah International, Inc.
	UT	--	U	2	U020668 U38727	627 740	
NICOR, Inc.*							
Belden Enterprises (50 percent)	—	— — — — — —	—SEE FOOTNOTE—	—			
North American Coal Corp.	ND	Indian Head	A	2	BK020273 M34980	1357 441	
Coteau Properties, Inc.	ND	Beulah-Hazen	P	2	M071813 M042819**	2034 764	
	ND	--	U	1	M163	400	
Falkirk Mining Co.	ND	Falkirk	P	1	M31053	160	
Northwest Energy Corp.							
Northwest Carbon Co.	UT	--	U	1	U46484	400	
Western Slope Carbon	CO	Hawksnest East	A	4	C17130 C27103 D042921 D056724	241 290 819 189	
Northwest Industries, Inc.							
Lone Star Steel Co.	OK	Milton	[illegible]	2	BLMC018820 NM059992	915 1680	
	OK	Starlight	A		BLMC02 85	1500	
	OK	--	U	1	NM050405	1116	

*NICOR, Inc. holds 50 percent interest in one lease. See subsidiary leaseholdings under Eastern Gas & Fuels Associates.

**This lease, although not included in a mine plan, is closely associated with the pending Beulah-Hazen lease. It has therefore been grouped with this lease for the purposes of OTA's analysis.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Northwest Industries, Inc.							
Lone Star Steel Co. (continued)	OK	--	U	2	BLMC018125	2560	
					NM050406	2400	
	OK	--	U		NM059996	719	
Occidental Petroleum Corp.							
Sheridan Enterprises, Inc.	CO	Loma Complex	P	6	C0125436	2446	
					C0125437	2357	
					C0125438	2560	
					C0125439	2483	
					C0125515	2560	
					C0125516	2523	
	CO	Joe s	U	1	D052546	60	
Pacific Gas & Electric Co.							
Eureka Energy Co.	UT	Sage Point-Dugout Canyon	P	5	U07746	2480	
					U089096	480	
					U092147	680	
					U0144820	2212	
					U07064	2416	
	UT	"	U	1	U05067	320	
Pacific Power & Light Co.*	WY	Dave Johns·oo	A	6	C054769	120	
					W0244167	1803	
					W0312918	3779	
					W038597	1400	
					W038602	2000	
					W041355	560	
	WY	Phillips Creek (1)	U	4	W0136194	322	
					W0136195	1477	
					W0136196	1560	
					W0324701	680	
	WY	Phillips Creek (2)	U	1	W0310712	40	

*Pacific Power & Light Co. holds 66.6 percent interest in an additional three leases in another mine. See subsidiary leaseholdings under Idaho Power Co.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Pacific Power and Light Co. (continued							
Resource Development Co.							
	WY	Antelope	P	3	W0321780 W0322255 B031719	2908 1869 40	
	WY	Cherokee	U		W0312917 W092141 W0313559 W092140	480 2480 640 671	
Spring Creek Coal Co.	MT	Spring Creek	A	1	M069782	2347	
Decker Coal Co. (50 percent)	MT	East Decker	A	1	M073093	9410	Peter Kiewit Sons, Inc. holds 50 percent interest in Decker Coal Co.
	MT	West Decker	A	4	M06770 M057934A M061685 M057934	40 1841 2360 720	
The Pacola Co.	OK	-	U	1	BLMI018108	960	There are four Federal leases in this lease block. The other three are held by Cameron Coal Co.
Padilla, Florentino	NM	I	U	2	SF075321 SF077779	120 40	
Panhandle Eastern Pipeline Co.							
North Antelope Coal Co. (50 percent)	WY	N. Antelope	U		W6023	320	Peabody Holding Co. holds 50 percent interest in North Antelope Coal Co.
Peabody Holding Co.							
Peabody Coal Co.	CO	Seneca 2 W	a		C19885	25	There are three Federal leases in this mine. The other two are held by General Dynamics Corp./Materials Service Co.
	CO		U		C° 14093	320	
	C°	-	U		C086654	160	
	CO	Seneca II	U		C088 99	2280	

*Peabody Holding Co. holds 50 percent interest in one lease in another lease block. leaseholdings under Panhandle Eastern Pipel ne Co.

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PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	
Peabody Holding Co. (continued)							
Peabody Coal Co.							
	CO	Denver Basin	U	3	C0112685	640	
					C0112686	640	
					C0112687	644	
	CO	Denver Basin	U	1	C0126477	760	
	UT	--	U	9	U0103108	2560	
					U0103131	2560	
					U0103132	1272	
					U0103133	1273	
					U0115656	2560	
					U0115657	2560	
					U096476	2552	
					U096477	1277	
					U098786	2550	
	UT	-	U	3	U0101140	1600	
					U0101141	1760	
					U0113254	160	
	MT	Big Sky	A	1	M15965	4307	
	WY	Rochelle	U	2	W0321779	8781	
					W37829	40	
	WY	East Wyodak	U	1	W0313667	2560	
	WY	Boar's Tusk	U	2	W0220486	1840	
					W3438	640	
(50 percent)	NM	Star Lake	P	1	NM2457	6336	Thermal Energy Co. holds 50 percent interest in this lease.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Peter Kiewit Sons, Inc.*							
Big Horn Coal Co.	WY	Armstrong	U	1	B025369	80	
Rosebud Coal Sales	WY	Rosebud	A	2	C057086 W483330	1273 130	
	MT	CX Ranch (PKS)	U	1	M061686	524	
Black Butte Coal Co. (50 percent	WY	Black Butte	A	1	W6266	14902	Union Pacific Corp. holds 50 percent interest in Black Butte Coal Co.
Cumberland Coal Co. (50 percent)	WY	South Haystack	P	1	W06024	408	Union Pacific Corp. holds 50 percent interest in Cumberland Coal Co.
Petroleum International							
	OK	--	U	1	NM3174	2840	
	OK	--	U	1	NM957	3342	
Phelps Dodge Corp.							
Western Nuclear, Inc.	WY	Western Nuclear	U	1	W022978	80	
Pitkin Iron Corp.**	CO	Cottonwood Creek	P	1	C020740	40	There are a total of three Federal leases at this mine. One is held by James Brothers Coal Company. The other is held jointly by Pitkin Iron Corp., Kermit James and Richard James.
Public Service Co. of New Mexico							
Western Coal Co. (50 percent)	NM	Bisti	P	3	NM0186612 NM0186613 NM0186615	2188 1240 2027	Tuscon Electric Co. holds 50 percent interest in Western Coal Co.
	NM	San Juan	[illegible]	5	NM071448 NM045197 NM045217 NM045196 NM28093	40 2565 1800 2467 3856	

*Peter Kiewit Sons, Inc. holds 50% interest in an additional 5 leases in two other mines. See subsidiary leaseholdings under Pacific Power & Light Co.
**Pitkin Iron Corp. holds 33.3 percent interest in one other lease. See leaseholding under James, Kermit and Richard.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Quaker State Oil Refining Co.							
Kanawha & Hocking Coal & Coke Co.	UT	Skyline, Belina No. 1 & 2, and O'Connor	A A&P P	3	U073120 U017354* U067498	557 1028 502	There are a total of seven Federal leases at these three mines. Three are held by McKinnon Marital Trust and one by Armeda McKinnon.
	UT	--	U		SL062605	053	
Riebold, Paul**	— SEE FOOTNOTE —						
	UT	--	U	1	SL049042	40	
Ruby Construction Co.	CO	Sun	U	1	D051698	46	
San Diego Gas & Electric Co.							
New Albion Resources Co.***	— FOOTNOTE —						
Sharon Steel Corp.							
U.S. Fuels Co.	UT	Hiawatha	A	3	SL025431 SL069985 U026583	2370 2356 1000	
Shell Oil Corp.	WY	Buckskin	A	1	W0325878	599	
	WY	N. Rochelle	U	1	W71692	2000	
	MT	Pearl	U		M069945	541	
mm	NM	-	U	1	SF076644	80	
Smith-Holladay and Associates, Ltd.	UT	--	U	1	U2810	80	

*This lease is in both the approved Belina mine plan and the pending O'Connor mine plan.
**Paul Riebold holds 50 percent interest in one lease. See leaseholdings under Chapman, Russell.
***San Diego Gas & Electric Co. holds 33.3 percent interest in 21 leases listed under Arizona Public Service Co.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Southern California Edison Co.* Mono Power Co.		— — — — — —	—SEE FOOTNOTE—	— —		—	
St. Joe Minerals Corp. Anchor Coal Co.	CO	Windjammer	P	1	D052501		
Standard Equipment, Inc. Mining Systems Corp.	OK	Rees-Milton	P	1	BLMI017902	680	
Standard Oil of Indiana Co. Empire Energy Corp.	CO	Eagle No. 5 & 9	P	3	C0126480 C0127865 D056298	366 43 41	
The Sun Co. Sunoco Energy Development Co.	WY	Cordero	A	1	W8385	6550	
	WY	Long Canyon	U	1	W03 3201	14,680	
Texaco, Inc.	WY	Lake DeSmet	U	5	W030052 W046349 W051959 W030009 W0321120	2203 160 320 1913 4821	
Texas Eastern Transmission Corp./ Fannin Square Corp.**	—	— — — — — —	—SEE FOOTNOTE—	— —	— —		
Texas Industries, Inc.	NM	--	U	1	SF0668 7	20	
Thermal Energy Co.***	—	— — — — — —	—SEE FOOTNOTE—	— —	—		
Thompson Creek Coal & Coke Co.	CO	--	U	1	D037766	120	
Tucson Electric Co. Western Coal Co.**** (50 percent)		— —	—SEE FOOTNOTE—		— —	—	

*Southern California Edison Co. holds 33.3 percent interest in 21 leases listed under Arizona Public Service Co.
**Texas Eastern Transmission Corp./Fannin Square Corp. holds 50 percent interest in one lease. See leaseholdings under Eastern Gas & Fuel Associates/Eastern Associated Properties Corp.
***Thermal Energy Co. holds 50 percent interest in one lease. See leaseholdings under Peabody Holding Co./Peabody Coal Co.
****Tucson Electric Co. holds 50 percent interest in Western Coal Co. which holds eight leases. See leaseholdings under Pub ic Service Co. of New Mexico.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	RE	NOTES
Union Pacific Corp.*	—	— — — — — —	—SEE		— — —	—	
U.S. Steel Corp.	CO	Somerset	A	3	D052504	1922	
					C033302	625	
		Blue Ribbon	A&P		C033301	1548	
	C°	Coal Basin	U	8	C0125485	200	
					C030344	517	
					C12638	315	
					C12639	800	
					C1894	120	
					C7852	160	
					C7853	717	
					C030346	640	
	CO	—	U	1	=°51669	°92	
	CO	--	U	1	C068389	560	
	CO	—	U	1	D052558	1922	
	UT	Geneva	A	2	SL046612	280	
					SL066145	1552	
	UT	B Canyon	P	1	SL068754	257	
	MT	U.S. Steel	U	2	M3831	2537	
					M3832	2559	
Urtado, Barney	NM	--	U	1	SF042800	41	
Utah Power & Light Co.	UT	Des-Bee-Dove	A	3	U02664	920	
					SL050133	80	
					SL066116	400	
	UT	Deer Creek-Wilberg	A		U1358	320	There are twelve Federal leases at this mine. Three are held by Cooperative Security Corp. and three are held by McKinnon Marital Trust.
					SL064607	614	
					SL064900	160	

*Union Pacific Corp. holds 5° percent in 5 leases See subsid ary leasehold ngs r Ashland Oil & Hunt Interests, Ideal Basic Industries, Inc., and Peter Kiewit Sons, Inc.

PARENT CO. Leaseholding Subsidiary (if any)	STATE	LEASE BLOCK OR MINE NAME	MINE PLAN STATUS	NUMBER OF LEASES	SERIAL NUMBER	ACRES	NOTES
Utah Power & Light Co. (continued)	UT	--	U	5	SL05122	80	
					U014275	80	
					U024317	400	
					U024319	1040	
					U06039	1360	
Wasatch Coal Co.	UT	C&W No. 1	P	1	SL063°	280	
Weaver, Henry L. and Opal	CO	Ohio Creek No. 2	A	1	C069942	80	
Welch, Evelyn and Wiggins, Shirley	CO	Harvey Gap	U	1	D043937	120	
West, S. H.	UT	--	U	1	U01°3 <	961	
Western Fuel Associates	CO	Deserado	P	2	D047201	513	
					C023703	2557	
Westmoreland Coal Co.							
Colorado Westmoreland Co.	CO	Orchard Valley	A	2	C25079	310	
					C27432	854	
Wiggins, Shirley*	— SEE FOOTNOTE —						
Wilberg, Eliza and Lloyd	UT	--	U	1	SL036407	80	
W.R. Grace & Co.**	CO	--	U		C0125957	3863	

*Shirley Wiggins holds 50 percent interest in one lease. See leaseholding under Welch, Evelyn.

**W.R. Grace & Co. shares 50 percent interest in one lease in another mine. See subsidiary leaseholding under Hanna Mining Co.

APPENDIX C

Acronyms, Abbreviations, and Glossary

Acronymns and Abbreviations

AAR — Association of American Railroads
ABS —Automated Block Signals
ACLDS — Automated Coal Lease Data System
AMC — American Mining Congress
AQCR — air quality control region
AQS — air quality standards
AVF — alluvial valley floor
BACT –best available control technology
BIA — Bureau of Indian Affairs
BLM — Bureau of Land Management
BN — Burlington Northern Railroad
bt —billion tons
CBO —Congressional Budget Office
CEUM –Coal Electric Utility Model (Forecasts)
CFR — Code of Federal Regulations
CNW –Chicago and Northwestern Railroad
CSMRI —Colorado School of Mines Research Institute
CTC —Centralized Traffic Control
DEIS — draft environmental impact statement
DOE — Department of Energy
DOI — Department of the Interior
DRI — Data Resources, Inc.
DSL — Department of State Lands (Montana)
EA — environmental assessment
EDF — Environmental Defense Fund
EGR — electric growth rate
EIA — Energy information Administration
EIS — environmental impact statement
EMARS — Energy Minerals Activity Recommendation System
EPA — Environmental Protection Agency
E.R.C. — Environmental Reporter Cases
ERCOT — Energy Reliability Council of Texas
ETSI — Energy Transportation Systems Inc.
F.2d — Federal Reporter, Second Series
FCLAA — Federal Coal Leasing Amendments Act of 1976
FEIS — final environmental impact statement
FERC — Federal Energy Regulatory Commission
FLPMA — Federal Land Policy and Management Act of 1976
F.R. — Federal Register
F. Supp. — Federal Supplement
FWS — Fish and Wildlife Service
GAO — General Accounting Office
GMO —General Mining Order
GPO —Government Printing Office
ICC — Interstate Commerce Commission
KRCRA — known recoverable coal resource area
LMU —logical mining unit
MARCA – Mid-Continent Area Reliability Coordination Agreement
MER — maximum economic recovery
mt — million tons
mty — million tons per year
NAAQS — National Ambient Air Quality Standards
NCA — National Coal Association
NERC – National Electric Reliability Council
NEPA — National Environmental Policy Act of 1969
NETS — National Energy Transportation System
NSPS — new source performance standards
OSM — Office of Surface Mining
OTA — Office of Technology Assessment
PILT — payment in lieu of taxes
PKS — Peter Kiewit Sons, Inc.
PPL — Pacific Power & Light Co.
PRB — Powder River basin
PSD — prevention of significant deterioration
PRLA — preference right lease application
SERI — Solar Energy Research Institute
SID — Secretarial Issue Document
SIP — State implementation plan
SMCRA – Surface Mining Control and Reclamation Act of 1977
SPP — Southwest Power Pool
SunEDCO – Sun Energy Development Co,
TSP — total suspended particulate
UP — Union Pacific Railroad
U.S.C. — United States Code
USGS — U.S. Geological Survey
WSCC — Western Systems Coordination Council

Glossary

Acre Foot: A measure of water 1 ft deep by 1 acre in area, or 43,560 cubic feet.

Alluvial Valley Floor: Those stream valleys located west of the l00th Meridian which: 1) are underlain by unconsolidated gravel, sand, silt, and clay; 2) have a stream flowing through them; 3) have a generally flat valley floor topographic surface; and 4) have an agricultural importance. The relative importance of these valleys is a function of the water supplies available in the specific valley area. The agricultural activities generally include irrigated or subirrigated hay lands, developed pasture lands, critically important grazing areas, or lands that could be developed for any of these purposes.

Approximate Original Contour: The surface configuration achieved by backfilling and grading the mined area so that the reclaimed area, including any terracing or access roads, closely resembles the general surface configuration of the land prior to mining and blends into and complements the drainage pattern of the surrounding terrain, with all highwalls and spoil piles eliminated.

Aquifer: A subsurface zone that yields economically important amounts of water to wells; a water-bearing stratum or permeable rock, sand, or gravel.

Area Strip Mining: A mining technique characterized by the use of a power shovel, dragline, or bucket wheel excavator for removing overburden. This type of mining first proceeds by constructing a trench or box cut in the overburden to uncover the initial strip of coal that is to be mined. After the coal has been removed from the bottom of the box cut, the "spoil" or overburden material covering the next strip of coal is removed and placed in the void left by the mining of the preceding strip of coal. Mining proceeds with succeeding operations until the limits of the mining area are reached.

Automated Coal Lease Data Systems (ACLDS): A computerized information system maintained by the Bureau of Land Management of the Department of the Interior for Federal coal leases and lease applications. ACLDS contains a wide variety of technical and administrative information on every lease and preference right lease application.

Best Available Control Technology (BACT): A technology or technique that represents the most effective pollution control that has been demonstrated, used to establish emission or effluent control requirements for a polluting industry.

British Thermal Unit (Btu): The quantity of heat energy required to raise the temperature of 1 lb of water 1° F at, or near, its point of maximum density (39.1° F).

Continuous Miner: A machine with rotating cutting bits used in underground mining to cut relatively soft coal from the coal face. The coal is removed by breaking the coal from the face and then transferring it to loading machines.

Continuous Operation: Requirement that a Federal lease must produce at least an annual average of one percent of logical mining unit reserves after diligent development has been achieved.

Conventional Mining: An underground mining technique in which specialized machines are used in sequence to perform individual mining operations. The mining face is first undercut with a cutting machine resembling a chain saw. A drill is then used to bore holes into the face at an appropriate spacing; the holes are then filled with an explosive. After blasting, the coal is fragmented and allowed to drop on the floor of the mine in front of a new face. The coal is removed, the roof is bolted for support, and the mining sequence is repeated. Conventional mining accounts for 35 to 40 percent of underground mining in the united States.

"De novo" Leasing: The original issuance of a lease or prospecting permit by the Federal Government.

Development Potential: An assessment of the prospects for a lease or lease block being developed and mined within the next decade, taking into consideration the reserves, mining conditions, geographic location, status of adjacent properties, surface resource values, environmental impacts, potential markets, transportation availability and community infrastructure. Three development classifications were used by OTA in this report:

- Favorable-development potential—The lease or lease block has favorable development characteristics overall; the lease(s) meet the threshold criteria for a viable mining property; there are no major technical or permitting problems or uncertainties associated with the lease development.
- Uncertain development potential—The lease

or lease block has uncertain development potential because development is contingent on factors such as transportation availability or synfuels development or because of lack of information about the lessee's development intentions, Property characteristics can be good or marginal.

- Unfavorable development potential—The lease or lease block has unfavorable development potential, generally because it has one or more of the following property characteristics: small reserves, difficult mining or reclamation conditions, poor quality coal, or isolated location.

Diligent Development: As used in this report, diligent development generally refers to the requirement in the Mineral Leasing Act that all lessees must make a reasonable effort to bring the lease into production. The Department of the Interior has issued regulations that define diligent development for Federal coal leases as actual production of commercial quantities of coal from the lease or the logical mining unit of which the lease is a part by June 1, 1986, or within 10 years after the lease is issued, whichever is later. Under certain conditions, the period for meeting diligence can be extended to June 1, 1991, for leases issued before passage of the Federal Coal Leasing Amendments Act of 1976.

Face: The solid unbroken surface of the coal seam exposed at the advancing end of the working place.

Federal Coal Lease: A lease issued under the Mineral Leasing Act of 1920 which grants the exclusive right to mine Federal coal subject to conditions set in the act, the lease, and applicable State and Federal laws and regulations.

Federal Coal Reserves: Coal reserves owned by the United States,

Federal Lands: Lands or interests in land, including subsurface mineral rights, that are owned by the United States, regardless of how ownership was acquired.

Federal Mine: A mine that includes a Federal coal lease in its mine area.

Grading: The leveling or elevation of land to a relatively smooth horizontal or sloping surface.

Lease Assignment: The sale or transfer of a lease or a partial interest in a lease from the current lessee to another.

Lease Block: A single lease or a group of two or more contiguous leases owned or controlled by the same lessee(s) or operator.

Lease Segregation: The division of an existing lease into two or more parcels at the request of the lessee. A new lease is then issued for each new parcel and the surviving lease is modified to reflect the reduced acreage, Lease segregation requires the approval of the Department of the Interior. Segregation is frequently used as a form of partial assignment.

Longwall Mining: An underground mining system that consists of a set of roof supports or "jacks" that are located parallel to the mining face, a conveyor system that runs along the base of the face, and a cutting mechanism that moves back and forth along the face cutting the coal out of the face and dumping it on the face conveyor for transport out of the mine. In a longwall system, parallel entries (typically from 300 to 600 ft apart are driven into the coal seam using continuous miners. Then an interconnecting passage is made between the entries. The exposed seam is then mined in successive slices using the longwall system. As the slices or panels are removed, the roof support system is moved forward and the unsupported roof is allowed to collapse into the mined-out area left behind.

Maximum Economic Recovery (MER): Requirement that all portions of the coal deposits within a lease having an incremental cost of recovery (including reclamation, safety, and opportunity costs) less than or equal to the market value of the coal, must be mined.

Mine Development: As used in this report, the process of acquiring detailed geological, engineering, environmental, technical, and economic data for mine planning, construction, and initial commercial operation,

Mine Plan: As used in this report a mine plan refers to: 1) an operating plan for a mine with Federal leases submitted to the U.S. Geological Survey (USGS) under the requirements of the Mineral Leasing Act of 1920; or 2) a mining and reclamation plan for a mine with Federal leases submitted to the U.S. Office of Surface Mining (OSM) under the Surface Mining Control and Reclamation Act of 1977. A mine plan is a detailed description of the operator's proposed method, rate and sequence of mining, environmental protection measures, and reclamation strategies. The mine plan must be approved by USGS and OSM and appropriate State agencies before mining can begin.

Mine Size: As used in this report: A small mine produces 100,000 tons of coal per year or less; a medium-sized mine produces between

100,000 to 500,000 tons per year; a large mine produces over 500,000 tons per year.

New **Source Performance Standards:** Standards set for new facilities to ensure that ambient standards are met and to limit the amount of a given pollutant a stationary source may emit over a given time.

Non-Federal Coal Reserves: Include private, State, local government, and Indian coal reserves.

Open-Pit Mining: A system of surface mining characterized by a series of benches, the number of which increases as the mine is deepened. These benches are each 40 to 50 ft in height and allow excavation to hundreds or thousands of feet.

Overburden: Earth, rock, or other consolidated or unconsolidated material that overlies a commercially valuable mineral deposit, such as a coal seam, especially those deposit which are mined from the surface through open cuts.

Preference Right Lease: Noncompetitive coal lease issued to the holder of a prospecting permit who discovers coal in commercial quantities on the land under permit.

Public Lands: Lands and interests in land owned by the United States and administered by the Secretary of the Interior through the Bureau of Land Management without regard as to how the United States acquired ownership, except lands located on the Outer Continental Shelf and lands held for the benefit of Indians, Aleuts, and Eskimos. Public lands are generally divided into public domain lands, which have never left Federal ownership, and acquired lands, which are not in the public domain and which have been obtained by the United States through purchase, condemnation, gift, or exchange.

Reclamation: Restoring mined lands to productive use; including replacement of topsoil, restoration of surface topography, and revegetation,

Recoverable Reserves: The amount of coal that can be economically extracted from a coal deposit of known location, quantity, and quality using currently available technologies. (See ch. 4 of this report for additional discussion of coal resource classifications.)

Recovery Rate: The percent of minable coal actually recovered. Typically 90 percent for a Western surface mine and 40 to 50 percent for an underground mine.

Room-and-Pillar Mining: An underground mining method in which coal is removed in a systematic pattern leaving behind mined-out 'rooms' and unmined coal 'pillars' to support the overlying rock. The actual extraction of coal in the room-and-pillar mine is accomplished with either conventional mining or continuous miners.

Royalty: A payment, either on straight fee per ton or as a percentage of the value of coal produced, to the owner of the resource for permitting another to mine and sell coal.

Severance Tax: A special levy, assessed at flat or graduated rates, on the extraction of natural resources.

Spoil: The overburden or material removed in gaining access to the commercially recoverable coal deposit, also called waste.

Spoil Pile (or Bank): An area where spoil or overburden material is deposited before backfilling; that part of the mine where the coal and other materials that are not marketable are left,

Surface Subsidence: The settling or sinking of the surface as a consequence of collapse of underlying strata because of underground mining.

Terrace Pit Mining: This method of surface mining combines the area-strip and open-pit mining techniques and is designed for the thick coal beds of northwestern Wyoming and southeastern Montana. The terrace pit mine has a system of benches like the open pit mine. However, there are more benches (six or seven) than with open pit mining. Also, the terrace pit mine, unlike the open pit mine, does not remain in the same location but rather moves across the property in a manner similar to a strip mine. Overburden is removed from one side of the pit, hauled around the pit ends, and dumped on the other side where coal has already been mined.

Undeveloped Lease: A lease for which no mine plan has been submitted,

APPENDIX D
Some Key References

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APPENDIX E

Availability of OTA Working Papers

The following OTA staff and contractor papers were used in the preparation of this report and will be made available in early 1982 through the National Technical Information Service:*

J, Russell Boulding and Deborah L. Pederson, Development and Production Potential of Undeveloped Federal Coal Leases and Preference Right Lease Applications in the Powder River Basin and Other Wyoming Coal Basins, Final Report, November 1981.

Douglas W. Canete, Iris A. Goodman, and Deborah L. Pederson, *Development* and Production Potential of Existing Federal Coal Leases in the Fort Union Region of North Dakota and Montana, Final Report, December 1981.

James S. Cannon, Karen L. Larsen, and J. Stephen Schindler, The Development Prospects for Federal Coal Leases in New Mexico, *1980-1991,* Final Report, November 1981.

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Karen L. Larsen and Nancy Greenebaum, Review of Undeveloped Federal Coal Leases in Utah: Results of Utah Coal Leasing Task Force, Final Report, May 1980. (Includes: Frank Hachman, "Market Factors Associated With the Assessment of the Development Potential of Federal Coal Leases in Utah, Draft Report" [University of Utah, Bureau of Economic and Business Research), May 1980,)

Jack C, Schmidt, Sanna Porte, and Arnold J. Silverman, A Review of Current Production and Anticipated Future Production on Federal Mines and Selected Undeveloped Lease Blocks in Montana and Wyoming, Final Report (Geoservices West), December 1981.

Martin E. Zeller, Karen L. Larsen, Iris A. Goodman, The Development Prospects for Federal Coal Leases in Colorado, 1980-1991, Final Report, November 1981. (Includes: Joan E. Martin for Colorado Energy Research Institute, "Market Factors and Production Contingencies Determining the Present and Future Demand for Colorado Coal, " final draft report, December 1980.)

*Requests for these reports should be directed to National Technical Information Service, U S Department of Commerce, Springfield, VA 22161

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