The U.S. Coal Industry in the 1990's: Low Prices and Record Production

by Richard Bonskowski

Introduction

This article describes and examines structural and operational changes in the U.S. coal industry in the 1990's. During the decade, U.S. coal production continued an established growth pattern, buttressed by steadily increasing demand for coal for electric power generation. This growth occurred during a time of stiff competition, including closings or acquisitions of a great many mines and increases in the average size and productivity of those that remain. Meanwhile, competing suppliers have cut coal prices while delivering a higher quality product.

During the 1990's, operating mines have continued to cut back the recoverable coal reserves they control, while actual demand for coal and capacity at mines have increased. By the end of 1997, the cushion of coal reserves at producing mines, measured in equivalent years of production, was at its smallest level during the 21 years the Energy Information Administration (EIA) has collected those data.

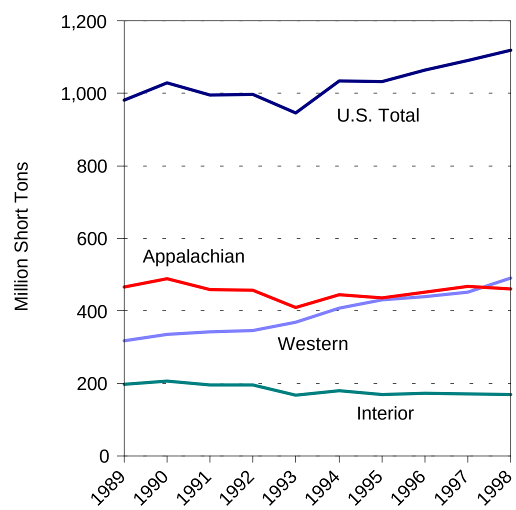
Using three-year increments for 1991 through 1997, the core tables and graphs in this article summarize coal industry trends of the 1990's. Data for 1986 are included to illustrate relative data levels prior to the 1990's and to enhance common base year data cited in an earlier EIA report.[1] Several tables and graphs include data for additional years, where available, to better illustrate trends.

Coal Industry Adaptations in the 1990's

The current growth trend in coal production began in 1961. The growth during the 1990's, though trending upward, included a strike-related downturn in production in 1993 and regional contrasts in production patterns (Figures 1 and 2). From 1986 to 1997, coal production increased by 22 percent, while the number of operating coal mines in the country declined by 59 percent, from 4,424 in 1986 to 1,828 in 1997 (Table 1). Coal prices, on the other hand, decreased by 45 percent in real dollar terms. Significant adaptations supporting these interrelated trends include:

- Increased average mine size
- “High-grading” of reserve properties, shutting down less competitive properties
- Concentration of productive capacity among fewer, large companies
- Significant gains in coal industry productivity
- Fiscal discipline imposed by vigorous competition.

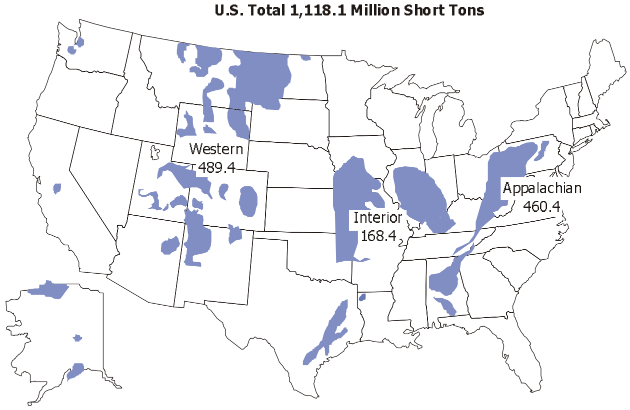
Figure 1. Coal Production by Region, 1989-1998



Sources: Energy Information Administration, *Quarterly Coal Report*, *October-December 1998*, DOE/EIA-0121(98/4Q) (Washington, DC, July 1999); *Coal Production*, DOE/EIA-0118, various issues; and *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998).

[1] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993).

Figure 2. Coal Production by Coal-Producing Region, 1998
(Million Short Tons)



Source: Energy Information Administration, "U.S. Production by State, July-December 1998," *Weekly Coal Production* summary (released May 7, 1999), Internet reference at http://www.eia.doe.gov/cneaf/weekly/weekly_html/wcpdecem.htm.

Increased Mine Size

In this discussion, "mine size" is equated with a mine's actual tonnage of coal produced. The Energy Information Administration (EIA), in its 1992 retrospective on the U.S. coal industry, noted a discernible trend toward larger coal mines in the 1970's, that was firmly established by the 1980's. EIA found that the percentage of coal production from mines of at least 1 million short tons per year rose to 63.5 percent in 1990 from 44.4 percent in 1980. The increase during the 1980's was supported principally by the expansion of existing surface mines in the western United States.[2] During that period, mines producing less than 50,000 tons per year[3] declined dramatically in number and combined total production, especially among the smallest, marginal mines producing less than 10,000 tons per year (Table 1).

During the 1990's, both trends have continued. In 1997, for example, million-ton-plus coal mines accounted for 75.5 percent of U.S. production. While the Nation's coal production grew at an average annual rate of 1.5 percent from 1991 through 1997, million-ton-plus mine production grew twice as fast, at an average annual rate of 3.1 percent. The average annual growth rate had been even more rapid from 1986 through 1991—2.3 percent overall and 5.8 percent for the million-ton class of mines.

Among the three coal-producing regions, increases in mine size, as in production share, were concentrated in the West and Appalachia (Table 2). In the prior decade, between 1980 and 1989, an EIA comparison of previously existing and newly opened mines showed that more than 200 million tons of growth in production from million-ton mines was supported primarily by increases in the size of existing underground mines in Appalachia.[4] By 1997, annual production at million-ton mines had increased by an additional 206 million tons, from 616 million to 822 million tons. Million-ton Western mines—mostly surface mines—made up 140 million tons of that increase and million-ton Appalachian mines—mostly underground—comprised 78 million tons of production increase. Production growth at million-ton mines in those two regions was offset in part by a decline of more than 12 million tons in annual production at million-ton mines in the Interior region.[5]

Figure 3 assigns U.S. coal mines to three size ranges in terms of production levels. From 1986 to 1997, as production from large mines grew to dominance, production from medium- and small-sized mines declined. Growth in production share at larger mines more than offset the decline in small- and medium-sized mines, driving the overall growth in national production. For million-ton-plus mines, this is reflected in a 26-percent increase in average size, from 3.14 to 3.95 million tons per year, between 1991 and 1997.[6]

The decline in production share of smaller mines corresponds with a decline in the percentage of smaller mines in operation. This is also a trend that began in prior decades (Table 1). Competition for market share in the 1990's, as coal prices continued to decline, has penalized smaller mines, which generally operate with less productive equipment and often rely on more labor intensive techniques than do the large mines. Unlike the larger operations, whose numbers stabilized as average mine size grew, the count of the smallest mines (less

[2] Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change,* DOE/EIA-0559 (Washington, DC, November 1992), pp. 20-21 and Table 7.

[3] Throughout this article, "tons" refers to short tons.

[4] B.D. Hong, F.L. Freme, and M.L. Mellish, Energy Information Administration, "A Profile of New Coal Mines in the 1980's," *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991), pp. 2-3.

[5] *Ibid*., pp.1-6; *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Table 6.

[6] In Table 1, average mine size = coal production ÷ number of mines, for each mine size.

Table 1. Number of U.S. Coal Mines, Distribution of Mine Size, and Coal Production by Mine Size Range, 1986, 1991, 1994, and 1997

Item	1986	1991	1994	1997
Number of Mines	4,424	3,022	2,354	1,828
Coal Production (million short tons per year)	890	996	1,034	1,090
Average Mine Size (thousand short tons per year)	201	330	439	596
Mine Size Distribution (thousand short tons per year)	**Number of Mines**			
1,000 or more	180	210	203	208
500 to 1,000	350	148	154	155
200 to 500	393	388	360	307
100 to 200	476	372	288	239
10 to 100	1956	1276	893	638
Less than 10	1069	628	456	281
	Percentage of Total Number of Mines			
1,000 or more	4.1	6.9	8.6	11.4
500 to 1,000	3.8	4.9	6.5	8.5
200 to 500	8.9	12.8	15.3	16.8
100 to 200	10.8	12.3	12.2	13.1
10 to 100	44.2	42.2	37.9	34.9
Less than 10	28.2	20.8	19.4	15.4
Coal Production by Mine Size Range (thousand short tons per year)	**Production (million short tons)**			
1,000 or more	497.0	658.7	727.1	822.4
500 to 1,000	118.1	105.0	108.1	106.2
200 to 500	121.8	121.7	114.6	97.8
100 to 200	66.2	53.3	42.1	34.6
10 to 100	82.8	54.8	39.6	27.8
Less than 10	4.4	2.5	1.9	1.2
	Percentage of Total Production Tonnage			
1,000 or more	55.8	66.1	70.4	75.5
500 to 1,000	13.3	10.5	10.5	9.7
200 to 500	13.7	12.2	11.1	9.0
100 to 200	7.4	5.3	4.1	3.2
10 to 100	9.3	5.5	3.8	2.5
Less than 10	0.5	0.3	0.2	0.1

Sources: Energy Information Administration, *Coal Production 1986,* DOE/EIA-0118(86) (Washington, DC, January 1988), Tables 1, 2, 3, and 7; *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October 1992), Tables 1, 2, and 4; *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995), and *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Table 6.

than 10,000 tons per year) plummeted by 74 percent from 1991 to 1997, while their average size remained essentially unchanged at about 4,000 tons per year.

Recoverable Reserves and High-Grading

EIA's recoverable reserves at producing mines are estimated by mine operators for each active property by mine operators, and constitute coal that is available to meet current and near-term demand at the end of the reporting year. As the number of operating mines was scaled back during the 1990's in the face of declining coal prices (Table 2), the reserves of coal that operators owned or leased also declined. Between 1991 and 1997, the mines controlling the greatest tonnage of reserves—the large mine category—cut back the greatest reserve tonnage. On a percentage basis, however, the 6.3-percent reduction in reserves at large mines was modest (Table 3). The major reductions, when viewed as a percentage of former reserve levels, affected medium-sized mines (46.0 percent) and small mine (61.6 percent).

Table 2. Regional Profiles of Coal Production, Mine Count and Size, Productivity, and Prices, 1986, 1991, 1994, and 1997

Region and Item	1986	1991	1994	1997
Total United States				
Coal Production (thousand short tons)	890,315	995,984	1,033,504	1,089,932
Number of Mines	4,424	3,022	2,354	1,828
Average Mine Size (thousand short tons)	201	330	439	596
Productivity (short tons of coal produced per miner per hour)	3.01	4.09	4.98	6.04
Average Mine Price (real dollars per short ton)[a]	$29.52	$22.08	$18.50	$16.14
Appalachia				
Coal Production (thousand short tons)	428,508	457,808	445,370	467,778
Underground	275,864	303,252	285,487	308,360
Surface	152,644	154,556	159,884	159,418
Number of Mines	3,990	2,676	2,068	1,602
Underground	1,942	1,385	1,058	807
Surface	2,048	1,291	1,010	795
Average Mine Size (thousand short tons)	107	171	215	292
Underground	142	219	270	382
Surface	75	120	158	201
Productivity (short tons of coal produced per miner per hour)	2.09	2.74	3.20	3.76
Underground	1.90	2.54	2.96	3.55
Surface	2.54	3.24	3.72	4.26
Average Mine Price (real dollars per short ton)[a]	$37.28	$29.48	$26.07	$23.62
Underground	W	$30.31	$26.69	$24.68
Surface	W	$27.83	$24.97	$21.57
Interior				
Coal Production (thousand short tons)	196,635	195,418	179,858	170,863
Underground	63,915	69,982	69,198	64,941
Surface	132,720	125,436	110,660	105,923
Number of Mines	313	248	198	149
Underground	69	67	53	43
Surface	244	181	145	106
Average Mine Size (thousand short tons)	628	788	908	1,147
Underground	926	1,045	1,306	1,510
Surface	544	693	763	999
Productivity (short tons of coal produced per miner per hour)	3.14	3.98	4.43	5.54
Underground	2.26	2.87	3.26	4.07
Surface	3.87	5.08	5.71	7.11
Average Mine Price (real dollars per short ton)[a]	$29.09	$22.46	$18.94	$15.94
Underground	W	$28.22	$23.17	$19.24
Surface	W	$19.24	$16.29	$13.92
West				
Coal Production (thousand short tons)	265,173	342,758	408,276	451,291
Underground	20,658	33,991	44,419	47,357
Surface	244,515	308,766	363,858	403,934
Number of Mines	121	98	88	77
Underground	43	37	32	24
Surface	78	61	56	53
Average Mine Size (thousand short tons)	2,192	3,498	4,640	5,861
Underground	480	919	1,388	1,973
Surface	3,135	5,062	6,497	7,621
Productivity (short tons of coal produced per miner per hour)	9.27	12.42	14.58	17.75
Underground	2.82	4.56	5.98	6.88
Surface	11.49	15.33	17.68	21.78
Average Mine Price (real dollars per short ton)[a]	$17.48	$12.03	$10.07	$8.47
Underground	$33.95	$23.04	$18.33	$15.92
Surface	$16.02	$10.82	$9.06	$7.60

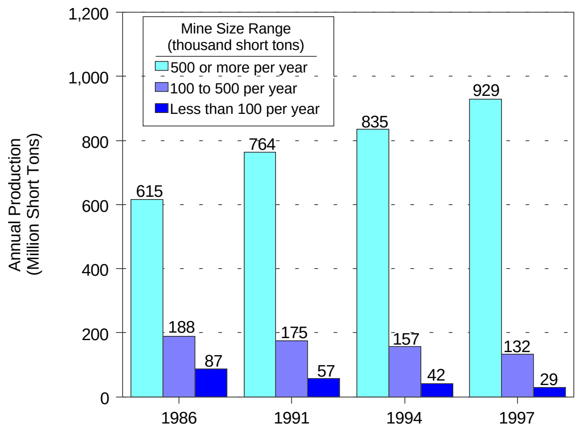
[a]In 1992 dollars calculated using GDP implicit price deflators.

W = Withheld.

Note: Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, *Coal Production 1986*, DOE/EIA-0118(86) (Washington, DC, January 1988), Tables 1, 23, and 48; *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October 1992), Tables 1, 21, and 25; *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995); *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1996); and *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998) Tables 1,51, 81, and 82.

Figure 3. U.S. Coal Production by Mine Size Range, 1986, 1991, 1994, and 1997



Source: Energy Information Administration (EIA), *Coal Production 1986,* DOE/EIA-0118(86) (Washington, DC, January 1988); EIA, *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October 1992), Tables 1 and 4; EIA, *Coal Industry Annual 1994,* DOE/EIA-0584(94) (Washington, DC, October 1985); and EIA, *Coal Industry Annual 1997,* DOE/EIA-0584(97) (Washington, DC, December 1998), Table 6.

As production increased, reserves of coal at producing mines declined concurrently, extending a downturn that started in 1986. In other words, reserves were being replaced at less than the rate of depletion. From 1991 through 1997, reserves at small mines (less than 100,000 tons per year) dropped by 61.6 percent, from 1,128 to 433 million short tons—a much more rapid decline than in the previous 5 years (1986-1991, Table 3). As small mines have closed, their reserves have become less and less salable to surviving mine operators. When marginally economic mines shut down due to low coal prices, the reserves theoretically become available for purchase or lease, but most owners of small reserve blocks have not secured new commitments. Small-mine production between 1991 and 1997 declined significantly, by 49.5 percent, but not as severely as reserves, because reserves at closed mines were not being claimed by other small mine operators. Small or isolated blocks of coal are not amenable to the larger-scale, higher-technology mining that can boost average productivity rates, except for a relative few that are situated adjacent to successful mines in the same coalbeds.

This culling of reserves to screen out the harder-to-mine or economically less suitable is a logical adaptation to low prices in a buyers' market, but the result is to temporarily or permanently disqualify those coal deposits from potential mining. The effect is not unlike a systematic "high-grading" of coal reserves. Though not the norm, high-grading in the classic sense may occur when a mine operator has little vested interest in the property and chooses to extract only the quickest- or easiest-to-mine parts of a coal deposit or only the highest-grade coal that will fetch a premium price, leaving the rest. Hard-to-mine, less valuable coal left in a once-mined area is considered spoiled, especially as caving and weathering take their toll. Such coal is rendered unminable for later economic recovery (unless markets or mining technologies improve dramatically).

The analogous high-grading of entire reserve blocks of coal in the 1990's—essentially removing marginal reserves from foreseeable mining—has occurred at many mines that were closed, especially at smaller mines. With prices low and competition keen, coal deposits once regarded as reserves at producing properties were found to be no longer marketable or not as desirable as competing reserves, or prices attainable would no longer support the costs of mining.

If reserve blocks contain coal of moderate to high sulfur content, for which markets are shrinking, the chances of permanent closure are high. For example, when one such mine, with active contracts, was recently acquired, the new owner chose to "consolidate the underlying mines" (i.e., shut down the higher-sulfur mine) and fill the contract obligations from another property from which it would "likely realize a higher margin due to reduced mining costs, reduced freight charges and higher quality."[7]

Operators of marginally profitable mines can tolerate only limited deterioration in mining conditions. Thinning or splitting coalbeds, fractures or offsets due to faulting, interruptions in coal deposits or coal quality due to sandstone- or clay-filled channels, or unstable roof rock are considered "geologic conditions," which in profitable coal reserves can usually be overcome. In marginal reserves, geologic conditions are often cited as the final reason for closing a mine (and removal of any remaining reserves from foreseeable mining). In one case in point, a large active underground mine was closed because of "geological problems." Soon thereafter, the company's three remaining active mines in the same area were put up for sale. Although the timing of the proposed sale may have been moved ahead to fend off

[7] Financial Times Energy, "AEI Shuts Chinook, Switches Hoosier Coal," *Coal Outlook* (December 21, 1998), pp. 1 and 8.

Table 3. Recoverable Reserves at Producing Mines and Number of Mines by Mine Size, 1986, 1991, 1994, and 1997
(Million Short Tons)

	1986		1991		1994		1997		Percent Change 1986-1991		Percent Change 1991-1997	
	Reserves	Number	Reserves	Number	Reserves	Number	Reserves	Number	Reserves	Number	Reserves	Number
Total--All Producing Mines[a]	**NA**	**3,175**	**NA**	**2,394**	**NA**	**1,898**	**NA**	**1,547**	**NA**	**-24.6**	**NA**	**-35.4**
Producing Mines Reporting Reserves	25,048	2,073	21,999	1,758	21,017	1,331	19,164	1,131	-12.2	-15.2	-12.9	-35.7
Percentage of Total at Reporting Mines[b]	92.6	64.0	95.2	73.4	94.4	70.1	95.5	73.1	NM	NM	NM	NM
Combined--Large Mine Category	**20,914**	**350**	**18,816**	**358**	**18,558**	**357**	**17,623**	**363**	**-10.0**	**2.3**	**-6.3**	**1.4**
≥1,000 per year	c	c	17,345	210	17,528	203	16,392	208	NM	NM	-5.5	-1.0
500 to 1,000 per year	c	c	1,471	148	1,030	154	1,231	155	NM	NM	-16.3	4.7
Combined--Medium-Sized Mine Category	**2,762**	**869**	**2,055**	**760**	**1,776**	**648**	**1,109**	**546**	**-25.6**	**-12.5**	**-46.0**	**-28.2**
200 to 500 per year	1,844	393	1,219	388	1,390	360	821	307	-33.9	-1.3	-32.6	-20.9
100 to 200 per year	918	476	836	372	386	288	288	239	-8.9	-21.8	-65.6	-35.8
Combined--Small Mine Category (10 to 100 per year)	**1,372**	**1,956**	**1,128**	**1,276**	**681**	**893**	**433**	**638**	**-17.8**	**-34.8**	**-61.6**	**-50.0**
50 to 100	723	683	251	472	417	NA	200	NA	-65.3	-30.9	-20.4	NA
10 to 50	649	1,273	876	804	264	NA	233	NA	35.1	-36.8	-73.4	NA

[a] Mines producing less than 10,000 short tons per year are "out of scope" for the EIA-7A survey and do not report reserves to EIA. Accordingly, both the reserves and the total number of producing mines in this table include only "in-scope" mines that produced 10,000 tons or more during the reporting year.

[b] Percentage reported under "Reserves" actually represents coal *production* at reporting mines expressed as a percentage of total in-scope production. Reserves at out-of-scope mines are not known, but reserves at producing mines are assumed to be roughly proportional to their coal production. "Reporting Mines" do not equal "Producing Mines" because some in-scope mines withheld reserves data.

[c] Reserves of 1,000,000 tons or greater were not published. All were reported as greater than 500,000 tons.

NA=Not available.

NM=Not meaningful.

Note: Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, *Coal Production 1986*, DOE/EIA-0118(86) (Washington, DC, January 1988), Tables 3 and 57, and Appendix E; *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October 1992), Tables 2 and 32, and Appendix D; *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995), Tables 2, 6, and 29, and Appendix D; and *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Tables 2, 6, and 30, and Appendix D.

pending operating liabilities, the coincidence of financial and "geological" difficulties is not uncommon.[8]

Loss or renegotiation of contracts can also cripple small- and medium-sized operations. In the 1990's, it has become commonplace for companies to sell off reserves, equipment, and mining rights after filing for Chapter 11 bankruptcy protection. More often than not, the financial problems of these marginal mines result from contract disputes and/or cancellations involving major customers.[9]

At medium-sized mines (100,000 to 500,000 tons per year), operators avoided a rate of closings as steep as at small mines. From 1991 through 1997, both mine numbers and coal production decreased less rapidly than at small mines (Table 1). Even though fewer in number, medium-sized mines made up a larger percentage of operating mines in 1997 because the total for all operating mines dropped even more, primarily due to small-mine abandonments. Production at medium-sized mines fell by 24.3 percent, from 174.9 to 132.4 million short tons, but recoverable reserves plunged

[8] "Jim Walter Sale Potential Will be Assessed by Firm," *Coal Week* (March 8, 1999), pp. 1-2.

[9] Financial Times Energy, "Coastal Buys Mines, Leases in Letcher County," *Coal Outlook* (December 21, 1998), p. 3.

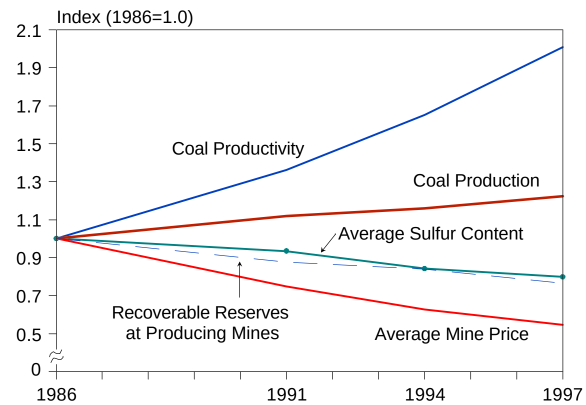
from 2,055 million short tons in 1991 to 1,109 million short tons in 1997, a loss of 46.0 percent and nearly twice the rate of production loss (Table 3). Compared to small mines, reserves at medium-sized mines are usually better suited for acquisition—by another medium-sized mine operator or by a large-mine operator—depending on the location, size, quality, and mining conditions of the reserves. On balance, however, these reserves have not often been needed by other medium-sized mining operations. Apparently, some have been absorbed by large operations but the rest have not been claimed, their ultimate minability uncertain.

As already noted, reserves at large mines have also declined, but by only 6.3 percent (from 18,816 to 17,623 million short tons) between 1991 and 1997. This took place while the number of large mines grew slightly, by 1.4 percent (Table 3). Effectively, the number of large mines and their reserves have stabilized during the 1990's. At the same time, however, their total production has continued to increase along with the relative proportion of active recoverable reserves they control. By the end of 1997, 11 percent of all mines controlled three-quarters of domestic production (Table 1).

In general, profiles of coal production and reserves between 1986 and 1997 reflect the dramatically rising productivity and the steadily declining coal prices of the period. The decline in coal prices may have started in the 1970's and 1980's, due to excess capacity and the influence of declining oil prices, but it has continued downward during the 1990's, in a self-reenforcing cycle (Figure 4). As investments, coal mines can take years to pay off, and once development capital is committed, coal mine owners may respond to continuing low prices by finding affordable ways to cut operating costs. One such way is to sell off reserves or allow leaseholds to expire, and shift capital into purchases of equipment and technologies that can improve productivity. Offers of coal at lower prices, in turn, stimulate further competition and the expectation among buyers of more low prices (at least until actual production reaches a level still closer to productive capacity). It is not surprising, then, to see the coal industry's investment in reserves decline as long as coal prices remain low and operators' very survival depends on increasing productivity (Figure 4).

When mine operators divest reserve holdings—unless severely overvalued—the better quality reserves are retained. Thus, the average quality of the coal produced, at least as indicated by lower average sulfur content, has kept improving (Figure 4). Lower sulfur levels can be seen as yet another mode of competition. In the context

Figure 4. U.S. Coal Production, Productivity, Prices, Reserves, and Sulfur Content, 1986 through 1997



Note: Average mine prices are indexed to constant dollars. Average sulfur content is based on coal delivered to electric utilities, reported on Form FERC-423.

Source: Energy Information Administration, *Coal Industry Annual 1995,* DOE/EIA-0584(95) (Washington, DC, October 1996), and *Coal Industry Annual 1997,* DOE/EIA-0584(97) (Washington, DC, December 1998), Tables 1, 25, 48, 80, and 106.

of pollution control measures mandated by the Clean Air Act Amendments of 1990 (CAAA90), low sulfur levels equate to added value to the customer and represent another way, besides price and productivity, to compete for customers. Declining sulfur levels in coal produced mean that reserves being retained at active mines have lower sulfur content, or that preparation facilities have been added or improved, or both. Preferential mining of lower-sulfur deposits is another aspect of a high-grade screening of reserve properties.

On the other hand, limited development of moderate-sulfur reserves—if they can be mined profitably with highly productive machinery and cleaned efficiently to meet customer specifications—is an approach that certain niche operators may use where another operator has failed. The market niches these mines serve, however, are limited, so contracts tend to be smaller and shorter in duration. As the CAAA90 Phase II requirements take effect in January 2000, the majority of electric power plants will be disinclined to burn even moderate sulfur coals.

Investment in reserves at producing mines, measured by the tonnage of reserves leased or held, has gone down in parallel with and in response to lower real-dollar coal prices (Table 4). At the same time, capital expenditures by the coal mining industry for development and

Table 4. U.S. Recoverable Coal Reserves at Producing Mines, 1990-1997
(Billion Short Tons)

	1990	1991	1992	1993	1994	1995	1996	1997
U.S. Total	22.8	22.0	21.6	21.5	21.0	20.1	19.4	19.2
Appalachia	6.0	5.8	5.4	5.6	4.9	4.5	4.5	4.6
Interior	3.7	3.7	3.6	3.3	3.1	2.8	2.8	2.6
West	13.1	12.5	12.6	12.6	13.1	12.7	12.1	11.9

Note: Totals may not equal sum of components due to independent rounding.
Sources: Recoverable Reserves, Energy Information Administration, Form EIA-7A.

Table 5. Capital Expenditures by the Coal Mining Industry, 1977-1992
(Million 1992 Dollars)

	1977	1982	1987	1992	Growth in Capital Expenditures, 1977 to 1992 (million dollars)	Growth in Capital Expenditures, 1977 to 1992 (percentage)
United States	**6,053.6**	**4,597.1**	**2,003.9**	**1,942.7**	**-4,110.9**	**-67.9**
Central Appalachia	1,754.4	1,421.5	745.6	701.5	-1,052.9	-60.0
Northern Appalachia	1,774.7	1,117.5	510.0	340.4	-1,434.3	-80.8
Illinois Basin	834.2	789.4	298.9	336.6	-497.6	-59.6
Powder and Green River Basins (WY, western MT)	680.8	189.9	165.5	159.5	-521.3	-76.6

Note: Capital Expenditures are funds expended for development and exploration of mineral properties, for new construction, and for purchased machinery chargeable to fixed asset accounts. Source data are available for every fifth year only; 1997 data not available at this time.
Source: U.S. Department of Commerce, Census of Mineral Industries, 1977-1992.

exploration, new construction, and purchased machinery have been trending downward since 1977 (Table 5). Outlays for these expenses could easily be reduced because previously explored working mines, their facilities, and equipment were widely available at negotiable costs.

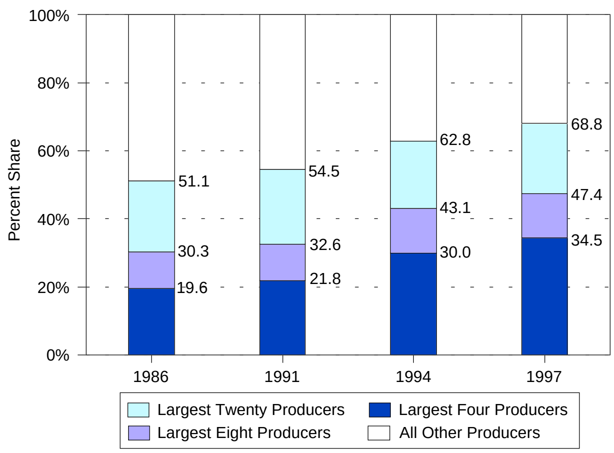
Uncompetitive reserves include: small blocks not well situated for highly productive mining or assignment to an active profitable mine, coals of lower quality (high or medium sulfur levels, high ash, and/or low heat content), and marginal reserves that are costly to mine because of adverse geologic settings. The characteristics of reserves being recovered at competitive mines are good quality, efficient minability, and/or advantageous location, which are increasingly necessary for profitable production and marketing.

Concentration of Productive Capacity

As noted above, in a time when coal prices are low and expected to remain so, the competition for reserves slackens and companies may put more of their capital into mining and loading equipment and preparation facilities. These are relatively smaller individual expenditures than reserves purchases, and they direct capital to improvements that can more quickly increase production and returns from already developed reserves. The growing concentration of production among the 20 largest coal producers between 1986 and 1997 implies good, marketable reserves and increased concentration of productive capacity at the largest producers (Figure 5). Concentration of productive capacity among the largest companies is also reflected in the regional origins of recent coal production. Sixty-seven percent of total U.S. productive capacity, or 885 million short tons, is concentrated in Western surface-minable and Appalachian underground-minable reserves (Table 6, Figure 6). During the 1990's, divestitures and acquisitions of coal companies have focused especially on companies with reserves, properties, and infrastructure in those two operational enclaves.

In 1986, coal reserves held by all producing companies were equivalent to 28 years of production. By the end of 1997, companies were content to control less than 18

Figure 5. U.S. Coal Production Concentration, 1986, 1991, 1994, and 1997



Sources: Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 6; *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995), Table 14; and *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Table 15.

years of production (Figure 7). This reversed the trend of the late 1970's and early 1980's, when coal prices were two to three times higher than today in real dollar terms, and locking up reserves could be viewed as securing of future returns.

At the same time that the relative size of reserves was declining, the gap between coal production and productive capacity narrowed. The reason, again, is low coal prices. Along with reserves, the closing of more than a thousand mines between 1991 and 1997 reduced underused productive capacity. The fact that coal production kept increasing faster than productive capacity caused an upward trend in capacity utilization (actual production as a percentage of capacity, Figure 6). Utilization of capacity in major underground mining regions in Appalachia and the Interior rose to 83 percent, largely as a result of the closing of less competitive mines and reserves. In the West, surface mine capacity utilization was maintained at an average of just over 78 percent during the 1990's. This reflects the relatively good availability of active reserves in the West coupled with highly productive mining techniques (Table 6).

Even while the average of utilization rates has remained steady in the West, the variance among those rates has widened. From time to time—first with changes in long-standing coal supply arrangements in Phase I, and then with the approach of Phase II of the Clean Air Act Amendments of 1990 (CAAA90)—productive capacity has been temporarily overtaxed at some mines. Uneven utilization rates, related to declines in production at some Western mines, occurred as customers turned to other Western coals with still lower sulfur content. On occasion, lower-sulfur coals have been temporarily unavailable to new customers

The most significant outcome of the 1990's for future productive capacity may be the decline in committed active reserves in the Eastern and Interior regions, relative to those in the West, and the net reductions in reserves as compared with annual production. For example, the *rates* at which active reserves have declined in Appalachia and in the West are similar, but when viewed in relation to continued production, average reserve levels in Appalachia have become low, while in the West reserves still constitute a robust buffer. Figure 8 illustrates the low and moderate ratios of reserves to annual production in Appalachia and the Interior. In Appalachia, the ratio dipped below the equivalent of 10 years' production in 1997, reflecting both diminishing availability of large, low- to moderate-sulfur reserve blocks suitable for efficient large-scale mining and closure of less competitive small and medium-sized mines whose reserves were formerly included.

The ratios of reserves to annual production in the Interior are higher than in Appalachia (about 15 years' production) not because of greater optimism, but because of falling demand (Figure 8). A greater percentage of the Interior mines were larger operations than in Appalachia, with longer average projected mine lives. Although a number of established mines have shut down during the 1990's, many of those that remain produce less coal than before from their sizable reserves and, therefore, project more years of production at current levels.

After years of reserve acquisition by producers, the ratio of reserves to production at Western mines is approaching a more conservative yet adequate level—nearly 28 years as of 1997. These reserves still provide a firm basis for new contracts and probably represent a more pragmatic level, considering recent low profit margins, than the 50-year ratio in 1986 (Figure 8).

Western mines have consolidated reserves through mergers and buyouts, with new leasing of Federal coal reserves in the 1990's essentially limited to a few instances of mines not located near available reserves previously leased by former competitors. Consolidation of reserves, concentration of companies, and even release of untimely leaseholds have marked the decade so far.

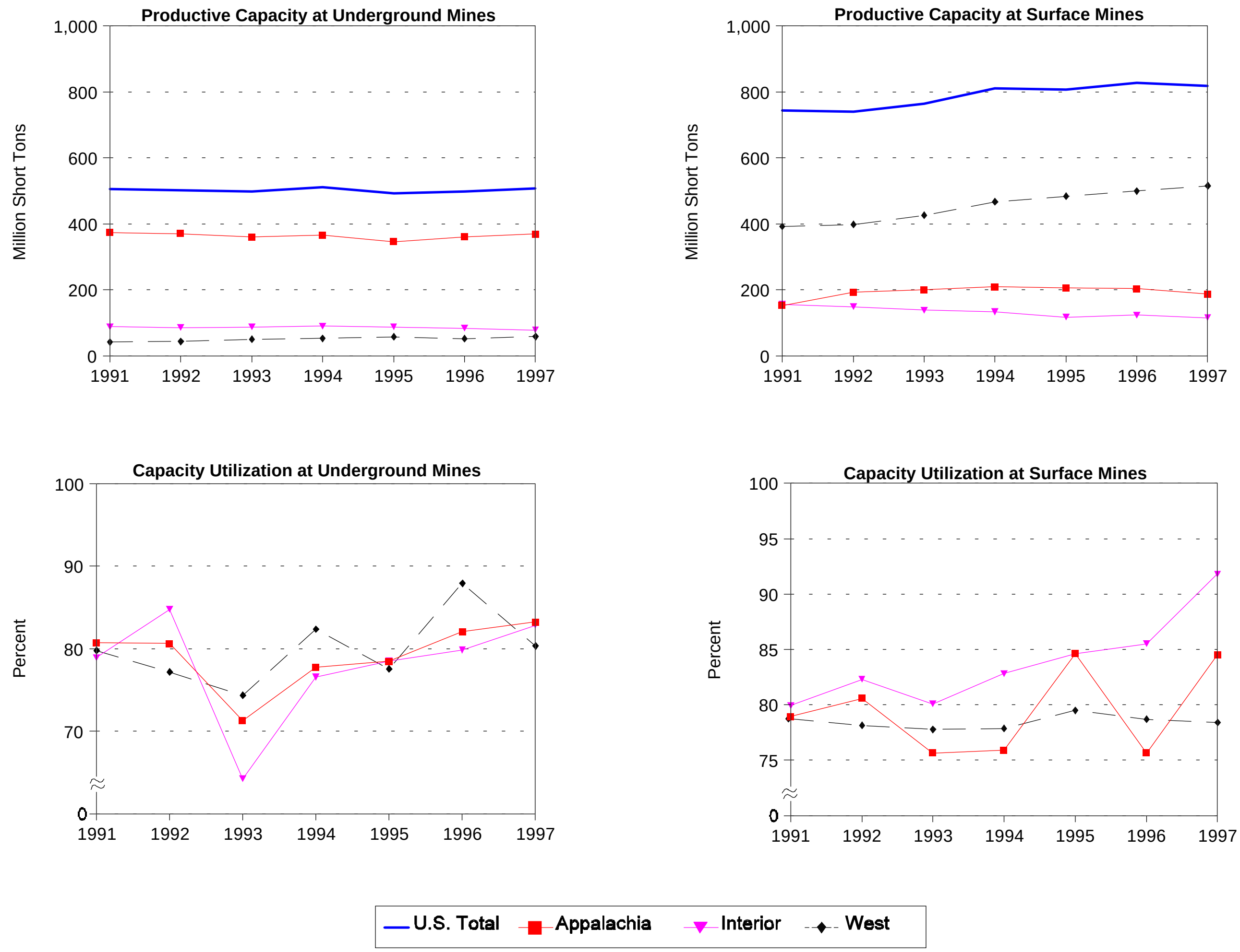
Table 6. Regional Profiles of Coal Reserves, Productive Capacity, and Capacity Utilization, 1991, 1994, and 1997

Region and Item	1991	1994	1997
Total United States			
Recoverable Reserves at Producing Mines (million short tons)	21,999	21,017	19,164
Production (million short tons)	996	1,034	1,090
Productive Capacity (million short tons)	1,248	1,321	1,326
Capacity Utilization (percent)	79.58	78.11	82.13
Appalachia			
Recoverable Reserves at Producing Mines (million short tons)	5,807	4,855	4,632
Underground	4,440	3,729	3,486
Surface	1,366	1,126	1,146
Production (million short tons)	458	445	468
Underground	303	285	308
Surface	155	160	159
Productive Capacity (million short tons)	568	576	558
Underground	375	366	370
Surface	194	209	188
Capacity Utilization (percent)	80.13	77.07	83.67
Underground	80.74	77.72	83.24
Surface	78.94	75.91	84.53
Interior			
Recoverable Reserves at Producing Mines (million short tons)	3,715	3,069	2,591
Underground	1,615	1,398	1,113
Surface	2,100	1,670	1,478
Production (million short tons)	195	180	171
Underground	70	69	65
Surface	125	111	106
Productive Capacity (million short tons)	245	224	194
Underground	89	90	78
Surface	157	134	115
Capacity Utilization (percent)	79.57	80.29	88.18
Underground	78.92	76.56	82.85
Surface	79.94	82.81	91.80
West			
Recoverable Reserves at Producing Mines (million short tons)	12,477	13,093	11,941
Underground	1,050	871	784
Surface	11,427	12,222	11,157
Production (million short tons)	343	408	451
Underground	34	44	47
Surface	309	364	404
Productive Capacity (million short tons)	435	521	574
Underground	43	54	59
Surface	392	467	515
Capacity Utilization (percent)	78.86	78.33	78.60
Underground	79.78	82.37	80.34
Surface	78.76	77.87	78.40

Note: Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October 1992), Tables 1, 31, and 33; *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995), Tables 1, 17, and 26; and *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Tables 1, 18, and 27.

Figure 6. Regional Differences in Productive Capacity and Capacity Utilization of U.S. Coal Mines, 1991 through 1997



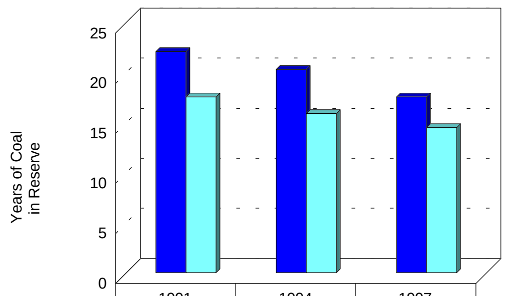
Sources: Energy Information Administration, *Coal Production 1991,* DOE/EIA-0118(91) (Washington, DC, October 1992), Table 33; *Coal Industry Annual 1994,* DOE/EIA-0584(94) (Washington, DC, October 1995), Table 17; and *Coal Industry Annual 1997,* DOE/EIA-0584(97) (Washington, DC, December 1998), Table 18.

Gains in Productivity

EIA measures coal mine productivity in short tons of coal produced per miner per hour. As average mine sizes have grown, productivity was clearly and proportionately improved at both underground and surface mines in all three coal-producing regions (Table 2 and Figure 9). Productivity gains have been similar among the mines of all regions, ranging from 68 percent for Appalachian surface mines to 144 percent for Western underground mines over 11 years. The level of productivity of the low-sulfur, Western surface mines, however, have been unattainable in the other regions (note scale differences among regions in Figure 9). Primarily owing to thick coal beds under thin, easily mined overburden, Western surface mining is three times as productive as the closest rival, Interior region surface mining.

The CAAA90, however, along with earlier clean air regulations, constitute the single most significant factor driving a continuing growth in demand for Western coal. With solid markets already assured and vast reserves of coal, Western surface mines, especially in the low-sulfur, thick coal deposits of the Powder River Basin (PRB), were well positioned to commit capital to large, efficient mining machinery and win over new customers. Between 1990 and 1995, in the years leading to Phase I of the CAAA90, PRB coal production increased by 81.4 million tons, most of which fed a 77.5-million-ton increase in shipments to electric utilities. Fifty-two percent of the 261 generating units at electric utilities

Figure 7. Ratios of U.S. Coal Reserves to Annual Production and Productive Capacity, 1991, 1994, and 1997



	1991	1994	1997
Ratio of Reserves to Annual Production	22.1	20.3	17.6
Ratio of Reserves to Productive Capacity	17.6	15.9	14.5

Sources: Energy Information Administration, *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October 1992), Table 33; *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995), Table 17; *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Table 18.

that were mandated to reduce sulfur dioxide emissions starting in Phase I chose to switch fuels, selecting low-sulfur coal as the least costly solution.[10]

In 1986, the productivity at Western surface mines—at 11.5 tons per miner per hour—was already 3.0 times higher than at Interior region surface mines. Then, between 1986 and 1997, the productivity of Western surface mines rose by a formidable 89.6 percent, outpacing the otherwise impressive 83.7-percent gain by Interior surface mines. By 1997, surface mine productivity in the West was 3.1 times higher than in the Interior (Table 2).

Despite unprecedented productivity gains, coal production from the Interior region continued to lose ground. Both the number of mines and the production of Interior region high-sulfur coal have been declining. This trend is expected to continue as the more stringent requirements of Phase II of the CAAA90 take effect on January 1, 2000 (Table 2).

Coal mine productivity in the Appalachian region also rose, nearly keeping pace with the Interior region. In Appalachia, underground mines led the productivity gains: 86.8 percent from 1986 to 1997, compared with 67.7 percent for surface mines. Underground productivity gains were largely driven by the increasing recovery rates and efficiency of longwall technology in use and by improvements in continuous mining. Surface mine productivity gains were related to larger scale operations in mountainous and hilly terrain and improvements in coal recovery and in mining equipment.

Although total U.S. coal output rose by 200 million short tons between 1986 and 1997, increased productivity brought about lower employment for miners. Direct employment in coal mining declined by nearly half during that period (Table 7). Some mine-related jobs not reported at 1990's coal mines may have been transferred to other categories, such as contracted geotechnical or reclamation services, independent highwall recovery services (thin-seam miners and augers), or surveying and geopositioning. In a broader context, according to advance statistics from the latest Economic Census, coal mining employment declined at several times the rates for other mineral mining and for the oil and gas industry, when compared on the same basis: between 1992 and 1997, coal industry employment fell by 28.9 percent, while employment in mining of all other nonmetallic minerals fell by only 5.9 percent and employment in oil and gas extraction declined by 11.6 percent.[11]

Discipline Imposed by Competition

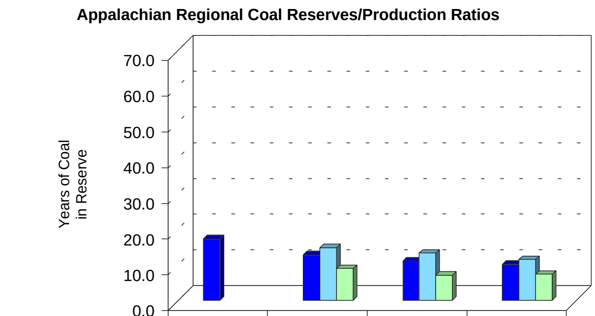
Coal prices had surged in the late 1970's and early 1980's due to external influences: high inflation and anticipation of rising long-term international oil prices and of long-term coal requirements for domestic electric power production and possible new applications. In reaction, coal suppliers scrambled to acquire reserves and opened new or formerly closed mines to supply the growing demand. In order to guarantee adequate future fuel supplies, electric utilities entered into long-term contracts, often with inflation adjustment provisions to reassure suppliers. Eventually, those contracts guaranteed prices that had become grossly above current market prices. By the mid-1990's, above-market coal contracts still comprised a large part of the contracts in force, but more than half will expire by 2005.[12] Some of the new 1970's-era reserves and mines had inherent

[10] Energy Information Administration, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, DOE/EIA-0528(97) (Washington, DC, March 1997), pp. 25, vii, and viii.

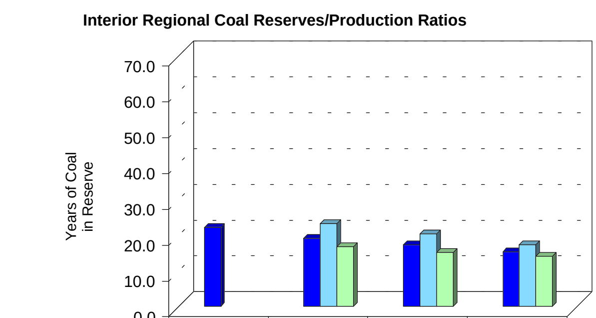
[11] U.S. Census Bureau, "1997 Economic Census: Advance Comparative Statistics for the United States," Internet web site, May 1999.

[12] Hill and Associates, Inc., *Generating Cost Study, 1996* (Annapolis, MD, 1996).

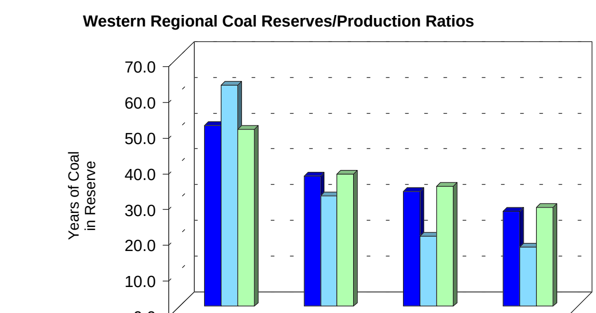
Figure 8. Ratios of U.S. Coal Reserves to Annual Production in Underground and Surface Mines by Region, 1986, 1991, 1994, and 1997



	1986	1991	1994	1997
Ratio of Reserves to Annual Production	17.1	12.7	10.9	9.9
Underground	W	14.6	13.1	11.3
Surface	W	8.8	7.0	7.2



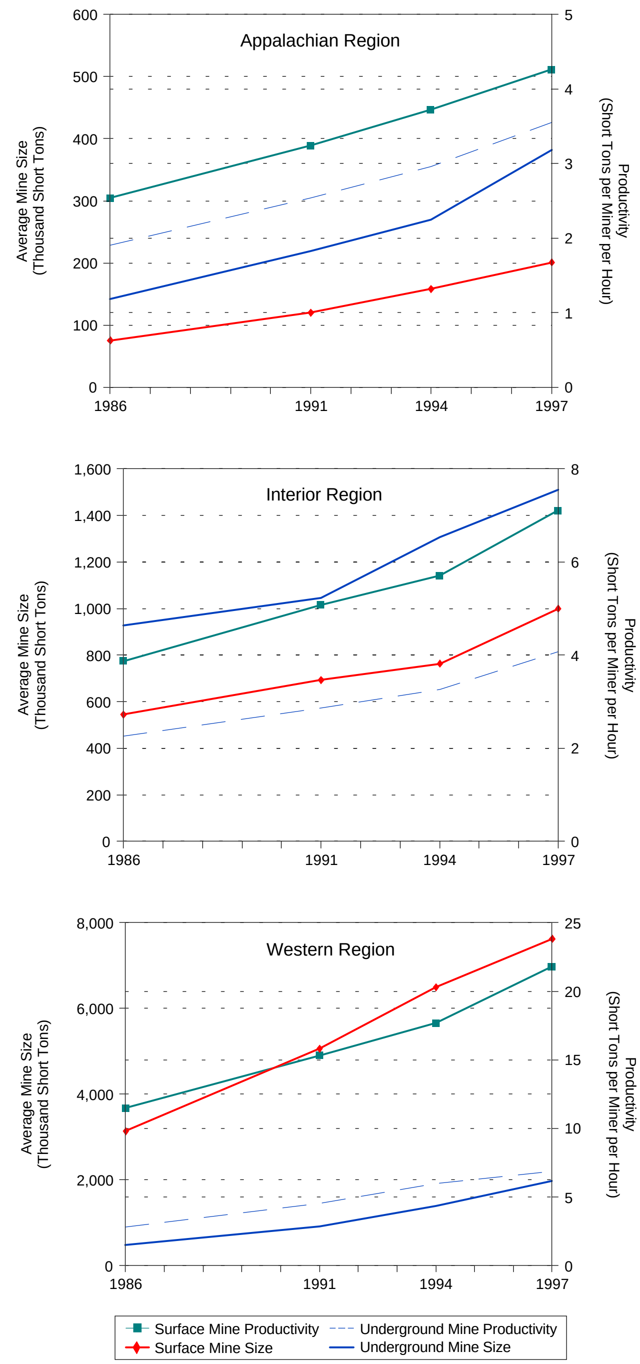
	1986	1991	1994	1997
Ratio of Reserves to Annual Production	22.0	19.0	17.1	15.2
Underground	W	23.1	20.2	17.1
Surface	W	16.7	15.1	14.0



	1986	1991	1994	1997
Ratio of Reserves to Annual Production	50.5	36.4	32.1	26.5
Underground	61.8	30.9	19.6	16.6
Surface	49.5	37.0	33.6	27.6

Sources: Energy Information Administration, *Coal Production 1986*, DOE/EIA-0118(86) (Washington, DC, January 1988), Table 58; *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October 1992), Table 33; *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995), Table 17; *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Table 18.

Figure 9. Correlations Between Average Coal Mine Size and Mine Productivity, 1986, 1991, 1994, and 1997



Sources: Energy Information Administration, *Coal Production 1986*, DOE/EIA-0118(86) (Washington, DC, January 1988) Tables 1 and 48; *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October, 1992), Tables 1 and 25; *Coal Industry Annual 1994*, DOE/EIA-0584(95) (Washington, DC, October, 1995), and *Coal Industry Annual 1997*, DOE/EIA-0118(97) (Washington, DC, December, 1998) (Tables 1 and 51).

Table 7. Employment at U.S. Coal Mines, Preparation Plants, and Tipples, by Mine Size Range, 1986-1997

Item	1986	1991	1994	1997	Percent Change 1986–1997
Number of Mines	4,424	3,022	2,354	1,828	-58.68
Coal Production (million short tons)	890	996	1,034	1,090	22.47
Average Mine Size (thousand short tons)	201	330	439	596	196.52
Number and Percentage Employed,[a] by Mine Size Range (thousand short tons)					
All Mines, Prep Plants, and Tipples	154,645	120,602	97,500	81,516	-47.29
Percentage of Total Employment	100.0	100.0	100.0	100.0	NM
1,000 or more per year	[b]77,730	52,730	43,589	39,448	-49.25
Percentage of Total Employment	50.3	43.7	44.7	48.4	NM
500 to 1,000 per year	([b])	13,849	11,614	9,727	([b])
Percentage of Total Employment	([b])	11.5	11.9	11.9	NM
200 to 500 per year	24,882	17,214	15,054	11,836	-52.43
Percentage of Total Employment	16.1	14.3	15.4	14.5	NM
100 to 200 per year	14,688	9,997	7,523	5,839	-60.25
Percentage of Total Employment	9.5	8.3	7.7	7.2	NM
10 to 100 per year	26,960	17,598	11,871	8,496	-68.49
Percentage of Total Employment	17.4	14.6	12.2	10.4	NM
Less than 10 per year	NA	NA	NA	NA	NA
Percentage of Total Employment	NA	NA	NA	NA	NM
Preparation Plants and Tipples[c]	10,385	9,214	7,849	6,170	-40.59
Percentage of Total Employment	6.7	7.6	8.1	7.6	NM

[a] Includes all employees engaged in production, coal preparation and processing, development, maintenance repair, shop, or yard work at mining operations. Excludes silt, culm, refuse bank, slurry dam, and dredge production except for Pennsylvania anthracite. No data available for mines producing less than 10,000 tons per year and preparation plants with less than 5,000 employee hours per year.

[b] Employment at 500-1,000 per year facilities combined with 1,000 or more as "Over 500."

[c] Not co-located with a mine.

NA = Not available. NM = Not meaningful.

Sources: Energy Information Administration, *Coal Production 1986,* DOE/EIA-0118(86) (Washington, DC, January 1988), Tables 1, 2, 15, 16, and 47; *Coal Production 1991,* DOE/EIA-0118(91) (Washington, DC, October 1992), Tables 1, 2, 13, 14, and 27; *Coal Industry Annual 1994,* DOE/EIA-0584(94) (Washington, DC, October 1995), Tables 1, 2, 6, and 42; and *Coal Industry Annual 1997,* DOE/EIA-0584(97) (Washington, DC, December 1998), Tables 1, 2, 6, and 43.

geologic or coal quality limitations, but these were not critical as long as coal prices were high. Sulfur dioxide emission regulations were an influence, but the standards in force prior to November 1989 did not affect most of the worst polluters because the standards applied primarily to new or substantially renovated power plants.

When oil prices did not rise as resolutely as expected and then entered periods of decline, other components of an anticipated, largely self-reliant U.S. energy economy failed to develop. By the mid-1980's, a new set of economic factors was in place which included fluctuating but lower oil and natural gas prices, deregulation of natural gas pricing, increasing competition among coal producers for the domestic market, and growing international competition in raw materials, manufactured products, and business and consumer services.

A close relationship between the price of coal and coal mine productivity has prevailed since the early 1980s.[13] As prices fall, marginal, inefficient mines close and productivity rises (Figure 4). Coal prices in the 1990's, as in the 1980's, have been controlled by excess productive capacity and governed by competition: competition

[13] Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change,* DOE/EIA-0559 (Washington, DC, November 1992), p. xi.

with other fuels, with other coal producers in a region, with coal producers in other regions of the United States, and with coal producers in other countries. Supply-side factors, such as inherent coal quality, geology and minability, and reserve location, influence the costs of mining and value of the coal, but excess supply gives the leverage to buyers seeking lower prices.

Natural gas during the 1990's has captured a significant portion of new electric generating capacity—a sector that went primarily to coal-fired units in the previous decade. Real-dollar prices of natural gas, though volatile, have been declining in recent years as supply systems, delivery systems, and market mechanisms have adjusted to natural gas deregulation and new operating routines.[14] Technological advances in combustion—the highly efficient natural gas turbine-based combined-cycle (NGCC) system—along with structural changes in electricity distribution systems have made natural gas the fuel of choice for 88 percent of new utility-owned generating units scheduled to go online between 1998 and 2007. In addition, nonutility generating capacity is currently only 9 to 10 percent as large as utility, but 60 percent of nonutility planned additions, between 1998 and 2001, will be gas-fired. Though environmentally preferable and quicker and less costly to install, most new NGCC units will supplement rather than supplant baseload generating capacity. The NGCC units will add only 6 percent to utility net generation capacity.[15]

Competition from natural gas has temporarily slowed the growth of new coal-fired generation capacity but consumption of coal still increased by 28 percent from 1986 through 1997, 90 percent of which, by 1997, was used to generate electricity.[16] Coal-fired units account for only 5 percent of planned new units between 1998 and 2007 but coal-fired net generation capacity is projected to grow because of anticipated increased utilization and, after 2007, additions to new capacity. EIA projections between 1997 and 2010, considering scheduled generating capacity additions and baseload mix, anticipate nearly a 14-percent increase in annual coal consumption at electricity generators.[17] These projections, and others like them, provide reasonable assurance of long-term coal markets and motivate large companies, especially with traditional ties to coal, to hold investment positions in coal for the long term.

Competition in coal prices was initiated primarily from within the coal industry—first from the large, highly productive Western mines, and then within each region from other mining operations competing more effectively with the Western coals. For the present, the remaining high-priced contracts negotiated in the late 1970's and early 1980's serve to subsidize operating costs, especially in the southern PRB in Wyoming. The result has been growing production share at Western mines and the loss of share in the Interior and Appalachian regions, and at less subsidized or less productive mines in all regions (Table 2), although it is anticipated by some that PRB coal prices will have to rise as the last of the old contracts expire over the next few years.[18] Mines in the Appalachian and Interior regions, on the other hand, now hold active reserves that will be depleted between 2004 and 2014 (Figure 8), and their production will still be in demand for many existing boilers. New mines will be needed, but current coal prices do not support the levels of investment needed to develop new mines in these regions.

The effects of international competition have been significant for certain premium coal and steam coal producers, but have had only minor impact on national production and prices. U.S. coal exports rose from 85.5 million short tons in 1986 to 109.0 million short tons in 1991 due to increased shipments to Europe. Since 1991, exports have decreased to 83.5 million short tons in 1997 and 78.0 million short tons in 1998. Even though U.S. coal exporters accepted ever lower prices between 1986 and 1998, falling from $44.56 to $34.30 per ton (in 1992 dollars),[19] increasing competition from Australia, Canada, and South Africa, declining coal consumption in Europe, the strong U.S. dollar, and the Asian economic crisis of the past 2 years have dampened U.S. exports. At their highest recent level, coal exports represented only 10.9 percent of U.S. production in 1991. They fell to 7.0 percent in 1998, at the same time that new record production levels were reached. Therefore, the overall

[14] Energy Information Administration, *Natural Gas 1996: Issues and Trends*, DOE/EIA-0560(96) (Washington, DC, December 1996), pp. 99-101.

[15] Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1998*, DOE/EIA-0095(98) (Washington, DC, December 1998), pp. 9 and 13 and Table 1.

[16] Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-1384(97) (Washington, DC, June 1998), p. 193.

[17] Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), pp. 82 and 161.

[18] J. Vaninetti and P. Best, "Coal Price Subsidies–the End of an Era?", *Coal Age* (March 1999), pp. 33-34.

[19] Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(98/4Q) (Washington, DC, (preliminary)), Tables 8 and 9.

significance to the coal industry of 30.9 million short tons fewer exports is slight.

The impacts were significant, however, for northern Appalachian companies and Colorado and Utah mines that normally export steam coal, and for certain central Appalachian mines that serve metallurgical and steam coal markets. For example, Pittston Coal lost $7 million in the first quarter of 1999, compared with a small operating profit one year earlier, and the company blamed this on poor markets for domestic steam coal and export metallurgical coal. With coal sales of only 3.5 million tons, versus 4.9 million tons one year earlier, some of the company's mines have been idled or closed, increasing associated shutdown costs and inactive employee costs, and reducing the per-ton profit margin to $1.39, versus $2.37 a year earlier.[20]

The Business Climate for Coal: Structural, Organizational, and Marketing Changes

As the new century begins, the coal industry is adapting to a changing business climate, with structural and operational features that reflect the broader economic environment. These include:

- New customer-supplier relationships, fostered by deregulation of the electric power industry and restructuring of railroads and energy markets
- Further price and product competition.

The coal industry is presently bigger, more competitive, and becoming more vertically integrated than at any time since World War II. With bigness has come less industry diversity: fewer mines, fewer companies, and fewer coalfields where local competitors sell coal to nearby utilities, industries, and institutions. For many, coal mining has become marginally profitable or unprofitable. The financial clout of the big companies has "raised the entry fee" for new would-be competitors. Slim profit margins require high sales volumes and optimal product recovery per dollar invested. Nor does the concentration of productive capacity among fewer, larger players guarantee their longevity; most divestitures over the past 8 years have been of mines over 500,000 tons per year. Flexible contracts, limited partnerships, and buyouts and mergers are bringing coal customers, shippers, and producers to the table to work out arrangements that share risks and profits. Even many medium-sized and small-mine operators, in order to finance and run profitable mines in the 1990's, are employing business and technical skills uncommon 20 years earlier.

Deregulation, Restructuring, and Market-Based Incentives

Deregulation, major restructuring, and market-based regulatory incentives among the energy and transportation industries during the past two decades have changed the shape of the coal industry today and for the foreseeable future. For example, the Staggers Rail Act of 1980 largely replaced Federal regulation of rail rates, routing, and service access with oversight, reduced rule making, and appeals and arbitration. Along with legislation on sulfur emissions, the "lower rail freight rates arising from deregulation" in the United States "remain key issues affecting the outlook for the market."[21]

As deregulated railroads consolidated in the late 1980's and the 1990's, they moved to increase profits by facilitating longer-distance coal runs between Western and Midwestern or Eastern utilities, using large unit trains with lighter-weight, high-capacity cars. In addition, railroads added tracks and track structures on congested sections of routes from the PRB, acquired more power locomotives to improve cycle times from Western coalfields, and offered lower ton-per-mile rates. Rail and waterway transporters coordinated efforts and improved rail-barge transloading facilities, incorporating coal-blending capabilities. This served the needs of new customers of Western coal whose boilers often required some ratio of bituminous coal to be blended with the new low-sulfur subbituminous coal for proper combustion. Further, barge operators deployed new "jumbo" barges to more efficiently deliver lower density coals to waterway customers and supported improvements of waterway locks to expedite larger tows.[22]

The CAAA90 subjected several hundred existing coal-fired electric generating units to stricter regulation, but gave all power producers greater discretion to create least costly overall strategies to achieve national pollution control targets. The most likely compliance

[20] Financial Times Energy, "Pittston Loses $8.3 Million in First Quarter," *Coal Outlook* (Arlington, VA, May 3, 1999), p. 6.

[21] International Energy Agency, *International Coal Trade: The Evolution of a Global Market* (Paris, 1997), p. 14.

[22] "NCA Developing New Markets for Coal Transportation, by Janet Gellici, *International Bulk Journal*, Surrey, England, March 1994, pp. 94-95.

option for the 435, mostly older, electric power units affected by Phase I of the CAAA90 was to switch to low-sulfur coal, and PRB coal was potentially a less expensive source for many of them. During the 2 to 3 years following CAAA90 enactment, legislatures and other authorities in Oklahoma, Illinois, Indiana, and Kentucky passed legislation or took other steps to protect in-State coal mining jobs through legal requirements or economic incentives designed to persuade in-State utilities to burn local high-sulfur coals and to install flue gas scrubbers. By early 1994 these challenges had been overcome as a result of lawsuits claiming violation of Federal laws protecting interstate commerce.[23]

Western coal already controlled a major part of U.S. coal production by 1990—more than 32 percent—but these rulings encouraged Western coal producers and, especially, Western railroads to invest in equipment and infrastructure improvements. That in turn reassured electricity generators concerned that new fuel switching might overburden the capacity of the systems to deliver, which had begun to happen in 1993 and 1994.[24]

The most innovative mechanism resulting from the CAAA90—the creation of an open market for trade in Government-sanctioned allowances to emit sulfur dioxide—is working well. This market approach may have far-reaching consequences, both in the way it is shaping decisions on the mix of power plants and levels of utilization and choice of fuels in the United States and in serving as the model for a proposed international open market in carbon dioxide credits and allowances.

The initiation of a deregulated, restructured U.S. electric power industry has made it feasible and likely that increasing numbers of coal producers and wholesalers, natural gas producers and distributors, and other types of energy producers will be party to mergers, partnerships, and/or contractual agreements among electric power producers, diversified energy marketing companies, and rail and barge lines. Kennecott Energy Company recently announced a "total company reorganization designed to improve and streamline work responsibilities and . . . build synergies throughout the company" and to improve mine productivity. Kennecott president Greg Boyce anticipated that "as the nature of the energy marketplace changes, coal companies will be required to participate in transactions that may include coal as well as electricity and natural gas."[25]

Coal companies will need to be ready to seek out and close similar agreements in order to survive. The restructured U.S. natural gas industry, because of its head start toward deregulation, has in place structural and marketing systems, including computerized trade and distribution, which are advantages in adapting to the restructuring electric power industry. An "immediate and direct spillover for the electric power industry that stems from the success of gas marketers has been the rapid entry of gas marketers into the electric power industry," resulting in dual-product marketers and an "accelerating pace of gas-electric mergers and acquisitions."[26]

Price and Product Competition

A 3-year lull in production increases between 1991 and 1993 drew attention to some changes that have since been behaving like trends. The 1991 downturn was attributed at the time to a slower rate of coal stock build-ups at electric utilities and declines in demand at coke plants and in the stocks held by coal producers and distributors.[27] The downturn was aggravated by consecutive losses in coal export levels from 1992 through 1994. These losses were overshadowed by a 7-month United Mine Workers strike in 1993 that selectively targeted certain large coal companies, primarily located east of the Mississippi, and by severe flooding in the upper Mississippi and Missouri River basins that disrupted coal deliveries and created backlogs of up to 5 months.[28] Although flooding and labor disruptions tend to be intermittent, both producers and customers have continued to keep lower stockpiles, and coal shipments for coke making and export have not recovered. Ironically, the 1993 strike may have hastened the decision of some Midwestern and Eastern utilities to switch to PRB coal, which is produced by non-union mines.[29] Coal customers who purchase from non-union

[23] *Financial Times Energy*, "Illinois Decides to Appeal Court Ruling," *Coal Outlook*, Arlington, VA, January 17, 1994, pp. 2-3.

[24] *Financial Times Energy*, "PRB Coal Supply Gets Scarce as Prices Rise," *Coal Outlook*, Arlington, VA, February 21, 1994, pp. 1 and 8.

[25] "Kennecott Set to Streamline and Consolidate Operations," *Coal Week* (New York: McGraw-Hill, May 31, 1999), p. 1.

[26] M. Jess, "Restructuring Energy Industries: Lessons from Natural Gas," Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(97/05) (Washington, DC, July 1997), p. xviii.

[27] Energy Information Administration, *Coal Production 1991*, DOE/EIA-0118(91) (Washington, DC, October 1992), p. 13.

[28] Energy Information Administration, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994), pp. xi-xiii.

[29] National Mining Association, Financial Conference, April 22-23, 1999, New York, NY, "Financial Experts Predict 'Good Outlook' for Mining in the 21st Century," *Mining Week* (Washington, DC, May 3, 1999), p. 4.

mines are less likely to retain large stockpiles in case of coal mine strikes.

Electric power plants now keep much smaller coal inventories on hand than as recently as 1986. In a modified version of “just-in-time” deliveries, power plants and some other coal consumers have come to rely heavily on the dependable transport of contract and spot coal purchases. This was possible because coal strikes have become less frequent and less disruptive and—along with equipment and trackage upgrades and ongoing restructuring and consolidation of railroads since the 1980 passage of the Staggers Rail Act—rail labor disruptions and service problems have diminished.

Smaller inventories have become common as more competitive policies were implemented in the electric power industry. Reduced stockpiles limit costs by tying up less capital in fuel stocks and trimming losses due to weathering of coal during excessive ground storage. In 1986, electric utilities routinely kept 86 days’ supply of coal on the ground. This ratio reached 75 days’ supply in 1991, and by 1998 the average stocks ratio had become 48 days.[30] That corresponds to end-of-year inventories of 162 million tons in 1986, 158 million tons in 1991, and 121 million tons in 1998—a total drop of 41 million tons of coal.[31]

As a result of this trend in utility stocks and of lower coal consumption in other sectors, by the end of 1998 all consumer stocks of coal had leveled off at 47 million tons below 1986 levels (Table 8). In the 12 years since 1986, consumer stocks of coal in the United States declined from 80 days’ supply, or the equivalent of 22 percent of annual consumption, to only 45 days’ supply, or 12 percent of annual consumption (Figure 10).

During the 1990's, as domestic foundry and steel output declined, coal consumption at coke plants has settled to historically low levels: 28.2 million short tons in 1998, or 12 million tons below the 1989 level of 40.5 million tons. U.S. coal exports remain lower than at the end of the 1980's. After reaching 109.0 million tons in 1991, exports have not again approached that level, settling at 78.0 million tons in 1998.

Table 8. U.S. Coal Consumption and End-of-Year Consumer Stocks, 1986-1998
(Million Short Tons)

Year	U.S. Consumption	End-of-Year Consumer Stocks
1986	804.3	175.2
1987	836.9	185.5
1988	883.6	158.4
1989	889.7	146.1
1990	895.5	168.2
1991	887.6	167.7
1992	907.7	163.7
1993	944.1	120.5
1994	951.5	136.1
1995	962.0	134.6
1996	1,005.6	123.0
1997	1,029.2	106.4
1998	1,042.7	128.1
Change in Quantities, 1986 to 1998	+238.4	-47.1

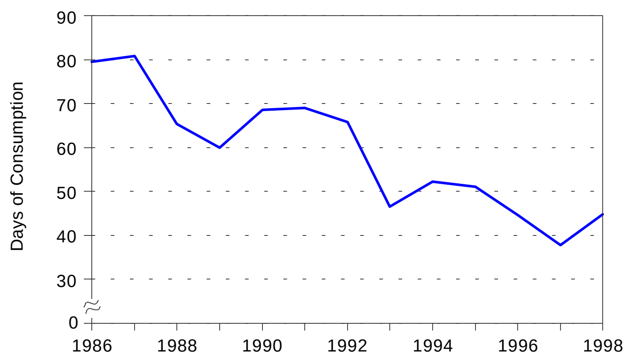
Source: Energy Information Administration, *Quarterly Coal Reports,* various issues.

Factors detracting from U.S. export growth in the 1990's included the phased lifting of international trade sanctions on South Africa between 1991 and 1994, policies of western European countries to deter coal consumption, the emergence of Australia as the major coal exporter to Pacific Rim countries, and growth in Indonesian coal exports. Economic conditions also affected U.S. coal markets. Japan, which normally drives a hard bargain as a major coal import market, stiffened its position as banking and currency problems affected cash flows and credit starting in the mid-1990's. In order to take advantage of keen international competition and universally declining coal prices, import customers in other Pacific Rim countries stopped accepting Japanese

[30] Based on year-end stocks and annual coal consumption at U.S. electric utilities.

[31] Energy Information Administration, *Electric Power Annual 1998, Volume I,* DOE/EIA-0348(98)/1, and earlier editions (Washington, DC, Internet version, May 1999), Tables A5 and A8. Coal stocks in 1997 reached abnormally low levels (98.9 million short tons, or 40 days’ supply) because of coal delivery shortfalls related to the Union Pacific-Southern Pacific railroad merger. In both 1996 and 1998, end-of-year coal stocks equated to a more normal 48 days’ supply. Also in 1998, as the effects of electric power industry deregulation started to be felt, eight coal-fired electric plants owned by utilities were sold to nonutilities (and thus were exempted from reporting further operational data), but the effects of their change of status on days of coal supply were relatively unimportant because days of supply is based on the *ratio* of stocks to consumption, not on total stocks or total consumption. In any case, the 1997 coal receipts (6.5 million tons at the eight plants) equated to only 0.7 percent of total coal receipts at electric utilities, so the absolute quantities were not significant.

Figure 10. End-of-Year U.S. Consumer Stocks as Days of Consumption, 1986-1998



Source: Energy Information Administration, *Quarterly Coal Reports*, various issues.

contract prices for their purchases and negotiated lowest available prices for their own contracts. In 1998 and 1999, and intermittently throughout the 1990's, high international dollar exchange rates associated with a strong U.S. dollar have undermined U.S. coal marketability.

In an extended era of low coal prices, all but the largest coal operations have found it more difficult to raise enough capital to open new mines. Traditionally, "project finance" lending for proposed coal mines was predicated on long-term contracts, usually with electric utilities. In recent years, State utility commissions have put pressure on electric power producers and coal companies to cut costs, and electricity generators have insisted on shorter contracts, with frequent re-openers triggered by changing power-market conditions.[32] These requirements can be met in many cases only by large, well capitalized corporations operating large mines.

New financing options in equity and high-yield capital markets, including private equity, "leveraged through subordinated debt and bank debt," are being offered to mining companies for expansion, mergers and acquisitions, refinancing, long-term capital, and "entree to new investor bases."[33] Although investors have retreated in recent years, because the mining industry, including coal, has not earned its cost of capital, the industry focus today is on expansion, as many experts predict globalization. Because of expected recoveries in Asian and Latin American economies, value investors may move dollars from current areas of momentum to undervalued segments of the market, such as mining. Overall, many in the industry expect investors to support further consolidation among mining companies.[34]

Because of dramatic changes in market forces in the U.S. energy sector over the past two decades, a coal futures market has been initiated in Central Appalachia. The New York Mercantile Exchange (NYMEX) is planning to launch a coal futures trading system in 2000 for coal contracts under standardized specifications, for shipment from designated reaches of the Big Sandy River in West Virginia. The factors that motivated this new market are increased price volatility and the need to manage risk, both for coal producers and electric power generators. Higher price volatility results from the increased efforts of electricity producers to cut costs as States approve deregulation. Power suppliers will no longer be able to pass cost increases on to customers. Increasingly, they have transacted coal purchases in spot markets, or with shorter, more flexible supply agreements or other ways to manage risk.[35] NYMEX is planning for a later extension of the trading system for PRB coal. Recently the London-based International Petroleum Exchange started investigating the creation of an international futures market because of "recent falls in coal prices and the move towards shorter term contracts, the need for risk management and a swaps market."[36]

Some medium-sized coal operations that remain in business have done so using innovative, progressive management methods and/or by serving "niche markets," such as smaller, local utilities, the Tennessee Valley Authority, State agencies, local industries, and customers needing coal with uncommon combustion characteristics. Some operators survive by specializing in certain mining environments (e.g., continuous mining, underground) in geologic conditions they are familiar with, permitting flexible use of equipment and personnel from one property to another—and usually avoiding unionized situations. Most emphasize effective and

[32] Energy Information Administration, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, DOE/EIA-0623 (Washington, DC, September 1998), pp. 10-12.

[33] National Mining Association, NMA Financial Conference, April 22-23, 1999, New York, NY, "Financial Experts Predict 'Good Outlook' for Mining in the 21st Century," *Mining Week* (Washington, DC, May 3, 1999), pp. 3-4.

[34] *Ibid.*, pp. 5-6.

[35] New York Mercantile Exchange, "New York Mercantile Exchange Coal Futures and Options Seminars," Internet announcement at: http://www.nymex.com/conf_coal.htm (June 1999).

[36] Japan Coal Energy Center, "Developing Market for Coal Futures," *JCOAL Coal Topics*, No. 17 (January 11, 1999), Internet reference at: http://www.jcoal.or.jp/e/topics_E17.html.

responsive marketing to keep a high percentage of their capacity committed to contracts.[37]

Intense competition has rewarded operators who are able to recognize and adapt to the technologies and mining methods that are right for their areas. The number of operating longwall panels in the United States declined from 96 faces in 1990 to 61 faces mining coal in 1998, of which 41 were in Appalachia. The slippage in the number of longwalls indicates not a decline in acceptance of the technique, but an increase in the size and productivity of the units and attention to best use of the technology. Productivity of longwall systems has increased because of greater length and face width of panels, increases in depth of cut, more horsepower, and stouter equipment.[38] In 1990, 96 longwall faces and associated continuous mining produced 115.0 million short tons of coal. By the end of 1997, 194.8 million tons were produced using only 61 longwall faces.[39]

Surface mining productivity in Appalachia has been bolstered by improvements in mine layout and mining technology, especially those related to improved economies of scale at larger operations. Many mines increased recovery rates by using computerized, sensor-guided thin-seam miners to recover coal in final cut highwalls that was either not economically or not as effectively recoverable with traditional augering systems. On balance, however, some of the gains in surface productivity were offset by less availability of suitable sites for new surface mines in established mining areas, accessible to good coal transportation options.

State interpretations of Federal regulations in the late 1990's allowed increases in the numbers and sizes of steep slope surface mining operations, including extensive mountain-top removal (MTR) complexes, primarily in West Virginia. Where feasible, steep slope mines and MTR can out-compete their more moderately scaled competitors because they tend to achieve higher recovery rates from greater numbers of multiple coalbeds than conventional contour mines. However, they produce large amounts of disturbed rock and unrecovered coal. In recent years, mine operators have been allowed to dispose of these "mine spoils" in "valley fills" where, with certain subsurface drainage preparations, they fill in proximate natural stream valleys and create relatively level reclaimed land.

In West Virginia, a controversial bill was passed in early 1998 that liberalized State rules on MTR and valley fills and intensified opposition to the practices. The prospects for continuing the improved productivity in Appalachian surface mining may hinge on the outcome of a suit filed in 1998 by citizens and environmentalists in West Virginia, claiming inadequate protection of surface stream waters in valley fills.[40] The suit resulted in a partial settlement requiring: (1) closer coordination among State and Federal agencies in the review of MTR permit applications, 38 of which were pending in West Virginia alone, and (2) an Environmental Impact Statement (EIS) to be developed by the Office of Surface Mining and Reclamation Enforcement on the environmental effects of surface coal mining and valley fills and on regulatory alternatives.[41, 42] The EIS is due in early 2001 and will consider future steep slope coal mining in parts of West Virginia, eastern Kentucky, Virginia, and Tennessee.

Meanwhile, a lawsuit in Federal court aimed at Arch Coal's proposed 3,100-acre Spruce Number 1 MTR mine in Logan County, West Virginia, which was scheduled for July 13, 1999, was delayed as attorneys for the plaintiffs and the coal company tried to work out an agreement on variances from "approximate original contour" rules. Such variances permit some MTR projects to replace mountain peaks with flat-topped land forms. Further, following advice of Justice Department attorneys that its legality would not be upheld in court, the U.S. Army Corps of Engineers withdrew the

[37] R. McMahon, "Acquisition in a New Era," Resource Data International, Inc., presented at Coal Properties Conference (Jupiter Beach, FL, March 20, 1997).

[38] S. Fiscor, "U.S. Longwall Census '99," *Coal Age* (February 1999), pp. 30-31.

[39] *Ibid*.; P.C. Merritt, "As Time Changes, So Do Longwalls, *Coal* (February 1991), p. 40; and Energy Information Administration, Form EIA-7A.

[40] "Mountaintop Removal Lawsuit Alleges Improper Rulemaking." Associated Press news release in *Charleston Daily Mail* (Charleston, WV), Internet site at http://www1.dailymail.com/biz06143.htm.

[41] Department of the Interior, Office of Surface Mining Reclamation and Enforcement, News Release, "OSM/WVDEP Release Final West Virginia Oversight Report and Action Plan to Address Mountaintop Mining Issues," (Washington, DC, May 4, 1999).

[42] Department of the Interior, Office of Surface Mining Reclamation and Enforcement, "OSM Action Plan: A Process for Providing Effective Coordination in the Evaluation of Surface Coal Mining Operations Resulting in Placement of Excess Spoil Fills in the Waters of the United States," (Washington, DC, April 13, 1999).

discharge permit allowing stream valley fills—the remaining point of disagreement at Spruce Number 1.[43]

In a related decision, the State of Kentucky recently agreed to compensate a mine operator for loss of coal reserves that would have been recoverable via contour mining within less than 250 feet (elevation) and less than one-half mile (distance) of the summit of the highest peak in the State. In this case, the State will remove more than 12,000 acres from permit-eligible surface mining.[44] Although the company can still recover most of the reserves at this site by underground mining, the eventual outcome of more than 2 years of protests and litigation will be critical to the future of the most productive form of surface mining in Central Appalachia during the 1990's.

Conclusions

From a myriad of companies and independent mine operators, sprawled over scores of coalfields, the U.S. coal industry evolved rapidly over the past 2 decades. During the 1990's, a pared-back coal industry emerged, dominated by large operations and large corporations, and starting to involve consolidated energy suppliers. Formerly led by bituminous coal producers throughout Appalachia, with substantial input from Interior region producers, in the 1990's productive capacity shifted increasingly to surface mine operators in preferred coalfields in the Western region. In some parts of central and northern Appalachia, meanwhile, successful premium and steam coal mines maintained enough productive capacity to sustain Appalachian totals even while the number of active mines declined (Tables 2 and 6). Western production, largely of low-sulfur subbituminous coal, surpassed Appalachian production in 1998, while Interior production continued to lose ground.

The shift to selected low-sulfur Western and Appalachian supply areas was spurred by Federal acid rain regulations. Major legal hurdles were overcome in the early 1990's through a series of decisions in Federal courts in favor of Wyoming, which challenged statutes in Oklahoma, Illinois, and Indiana designed to persuade local power producers to make long-term commitments to use in-State coal. As deregulated railroads consolidated in the late 1980's and the 1990's, they moved to increase profits by facilitating longer-distance coal runs to Midwestern and Eastern utilities, using large unit trains with high-capacity cars (100 tons or greater), and by offering improved trackage, rates, and cycle times from Western coalfields.

During the 1990's, coal producers began to feel the effects of electricity deregulation. Electric utilities and other power producers came under pressure to shed high-cost, long-term coal supply contracts and enter into more flexible, risk-sharing supply agreements. The downward trend in coal prices favored highly productive coal suppliers, initially those located in the near-surface, thick coal deposits of the PRB, but eventually energizing the more productive mine operators in all producing regions. Successful coal producers and their customers now benefit in one or more ways from economies of scale. In terms of physical scale, benefits derive from huge Western surface mines; big, efficient longwalls; large, automated loadouts and lower rail rates for major shippers; and efficient unit trains made up of larger, higher-capacity coal cars. On the fiscal side, the grand scale of financing or self-capitalization options at coal production operations backed by large corporations or investing partnerships permits risk-averse customers to seek optimal coal prices and quality without potentially costly long-term contract commitments.

[43] "Army Corps Pulls Arch Coal Permit," *Charleston Daily Mail* (Charleston, WV, June 25, 1999).
[44] "Potential Resolution Emerges for KY Mountaintop Coal Conflict," *Coal Week* (April 26, 1999), p. 1.